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Abstract

Within the transition to climate-neutral energy systems, hydrogen has the potential to support decarbonization of multiple sectors. Just like in electricity markets, volatility in hydrogen supply and process-specific demand may lead to volatile prices in a hydrogen market. This volatility may affect the interplay of hydrogen and electricity markets, which remains insufficiently explored. This study investigates fundamental price formation mechanisms for hydrogen and electricity, emphasizing their mutual dependencies, volatility, and the impact of short-term system conditions such as weather and demand variability. Additionally, it explores how these dynamics respond to variations in system configurations. Using the European energy system model DIMENSION, enhanced to incorporate detailed hydrogen supply and demand options including storage, cross-border trade, and updated import cost data, this study derives shadow prices as the basis for the subsequent statistical analysis. Results show that hydrogen and electricity prices are governed by short-term interactions. While electricity price formation can be well explained by renewable generation and demand, hydrogen prices emerge to be more structurally driven. Storage dynamics and cross-border trade moderate hydrogen price formation next to electrolysis. Strong price coupling between the hydrogen and electricity market likely occurs under low residual load conditions dominated by electrolysis, whereas decoupling arises during high residual load situations dominated by storage discharge. The electricity-to-hydrogen price ratio averages 0.56, lower than previous estimates, primarily due to the consideration of inflexible hydrogen imports and infrastructure constraints. Furthermore, the analysis indicates that short-term price signals alone may be insufficient for investment recovery, highlighting the need for complementary market mechanisms to develop a liquid hydrogen market.

Keywords: Hydrogen, Electricity, Energy system modeling, Price formation, Climate neutrality
JEL classification: C61, D47, Q21, Q41, Q48

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1. Introduction

The global energy transition toward climate neutrality has positioned hydrogen (H_2) as a promising pillar in the decarbonization of multiple sectors. As an energy carrier, hydrogen demand could span across industries, potentially exhibiting relatively rigid demand patterns, and could extend into sectors like (central) heating and electricity, where demand might be more dynamic. The heating sector might experience temperature-dependent variations, leading to both seasonal and intraday fluctuations, while the electricity sector could exhibit significant volatility, driven by the use of hydrogen in power generation. Furthermore, the sourcing of hydrogen can be diverse, with imports from non-European regions, domestic production, or imports from neighboring countries, each contributing to diverse prices for hydrogen.

Much like for electricity (EL), heterogeneity and volatility in hydrogen supply and demand could lead to a dynamic price structure when hydrogen is traded in the market. The European Energy Exchange intends to development market mechanisms for hydrogen (EEX, 2025). Additionally, recent infrastructure plans propose hydrogen pipelines to connect different market regions (ENTSO-E and ENTSOG, 2024). In such a setting, the diverse supply and demand structures for hydrogen would shape market equilibrium, influencing hydrogen prices accordingly. Those effects can also be diverse because of the interdependencies with the electricity sector. Additionally, the presence of hydrogen storage, acting both as suppliers and consumers, would introduce further complexity into the pricing dynamics.

Despite the increasing focus on hydrogen within the energy transition, significant uncertainties remain around the level and volatility of future hydrogen prices. These uncertainties hinder investments in hydrogen infrastructure, particularly in storage and electrolyzers, due to unclear profitability (Odenweller and Ueckerdt, 2025). Major concerns are the unpredictability of price developments and competition with alternative technologies, such as electricity and pumped hydro storage, which offer comparable energy storage solutions. This uncertainty, coupled with a fundamental lack of understanding of how region-specific and daily hydrogen prices emerge, limits investor confidence and reduces planning security.

This study seeks to address these challenges by investigating the fundamentals of hydrogen price formation and their interdependencies with electricity prices. The analysis includes a comparison of price structures, followed by more granular assessments depending on different market situations. Co-integration and correlation analysis asses the interdependencies between hydrogen and electricity prices. Regression analysis determines key drivers on price formation. In addition, price ratios and the statistical properties of prices in both markets are investigated. The robustness of these findings is further evaluated through sensitivity analysis across different system configurations. To compute the relevant data for the analysis, the European energy system model DIMENSION is expanded to enable high-resolution, integrated dispatch calculations for both electricity and hydrogen systems, incorporating up-to-date cost data for hydrogen imports and updated infrastructure parameters.

Different literature streams already address the effects of cross-sector integration of hydrogen. Its importance as a sector-coupling technology necessitates integrated modeling approaches that consider both electricity and hydrogen systems. Several studies have explored such integrated models, often focusing on robust investment decisions under varying scenarios. For instance, Caglayan et al. (2020) developed a robust energy system design that considers hydrogen infrastructure, quantifying the necessary storage capacities. Their focus on robustness against different weather years highlights the significance of external factors in hydrogen system planning. Similarly, Kondziella et al. (2023) used 192 scenarios to assess uncertainty regarding hydrogen storage demand, while Frischmuth et al. (2024) also examined the role of uncertainty in storage needs. In addition, Gawlick and Hamacher (2023) investigated optimal energy systems that integrate both electricity and hydrogen, and Lüth et al. (2023) analyzed the trade-offs between electricity and hydrogen infrastructure, emphasizing the sensitivity of investment decisions to hydrogen prices. The role of hydrogen in cost minimization and infrastructure planning has also been addressed by Gils et al. (2021), who identified hydrogen transport infrastructure as essential for reducing supply costs. Additionally, Durakovic et al. (2023) studied the impact of hydrogen production on electricity prices across different European regions, while Bellocchi et al. (2023) focused on hydrogen's role in decarbonization pathways for Italy's energy system, showing that while CO_2 emissions could be reduced by 49%, the associated annual costs would increase by 8%. Neumann et al. (2023) compared system costs across different levels of hydrogen network expansion, and Frischmuth and Härtel (2022) examined how varying hydrogen procurement strategies influence investment decisions. Last, Keutz and Kopp (2025) investigate how different Take-or-pay rates influence the need for hydrogen storage. They find that a higher amount of inflexible long-term contracts for hydrogen increase the need for hydrogen storage.

The interactions between hydrogen and electricity have been the subject of increasing attention, especially in terms of how sector coupling technologies influence electricity prices. Mathematical models, often calculated over 8760 hours to simulate a full year, have provided insights into these dynamics. For example, Liski and Vehviläinen (2023) demonstrated how marginal changes in electricity demand can alter equilibrium prices, resulting in distributional effects between producers and consumers. Ruhnau (2022) explored how electrolysers' electricity consumption increases electricity prices during peak hours and stabilizes the market value of renewable technologies. Frischmuth and Härtel (2022) analyzed how hydrogen procurement strategies affect electricity prices and price duration curves.

Research examining the influence of electricity prices and energy assets on hydrogen prices remains relatively limited. Early studies, such as Hesel et al. (2022), explored the bidirectional relationship between electricity and hydrogen, demonstrating that renewable energy sources and electrolysers are complementary technologies that enhance each other's profitability. Schönfisch (2022) investigated the development of a global hydrogen market and concluded that cross-border trade in pure hydrogen becomes economically viable in scenarios with high shares of renewable energy-based low-carbon hydrogen production. This viability is driven by the uneven global distribution of low-cost renewable energy resources, creating significant hydrogen price differentials between countries with high demand but limited renewable potential and those with abundant, cost-effective resources. Koirala et al. (2021) introduced a framework integrating electricity, hydrogen, and methane markets, with a focus on the Netherlands, highlighting hourly price interactions but leaving daily dynamics for other countries such as Germany unexplored. Finally, Frischmuth et al. (2024) conducted a high-resolution dispatch analysis of hydrogen storage but did not address the daily variability in hydrogen prices. In summary, while existing research has provided valuable insights into integrated energy systems featuring hydrogen and electricity, the more granular interactions between these two markets on a daily basis with a focus on Germany, as well as the underlying market dynamics that govern their price relationships, remain insufficiently explored. Examining the price relationship between these two markets would provide valuable knowledge to policymakers, investors, and researchers, enabling them to evaluate different decarbonization options without necessarily running energy system models.

This paper seeks to address the existing research gap by answering two key questions: How do short-term effects, such as weather and demand variability, shape hydrogen and electricity price dynamics? How do short-term price interactions change under different energy system configurations? To answer these questions, the paper presents enhancements to the existing European energy system model DIMENSION by a daily resolution of Power-to-X (PtX) fuels[1]. In addition, enhancements cover the integration of hydrogen storage, cross-border trade capacities, and up-to-date data for oversea imports via long-term contracts (LTCs). To address the uncertainty around the future system developments, sensitivities reflect varying levels of hydrogen demand and degrees of interconnection between countries through Net transfer capacities (NTCs) for hydrogen.

[1]Power-to-X fuels, as defined in this study, refer to synthetic fuels such as diesel, gasoline, hydrogen, kerosene, natural gas, or oil. The model incorporates all production technologies for these fuels that are considered climate-neutral.

Doing so, this research paper makes the following contributions to the existing literature:

- Development of an enhanced energy system model for the integrated optimization of the European electricity and hydrogen market.
- Analysis of hydrogen and electricity price structures, volatility, and interdependencies.
- Examination of short-term effects and system configurations that influence hydrogen and electricity price dynamics.

The analysis focuses on Germany and assumes a liquid market for hydrogen in 2050 with daily resolution to isolate and quantify the effects of market-oriented provision of hydrogen next to electricity. Moreover, the analysis is limited to changes in shadow prices derived from the equilibrium constraints for electricity and hydrogen, interpreted as market prices, without considering other components of prices, mark-ups or policy instruments. Thus, an important part of this study is the reflection on the model's limitations and assumptions that influence price formation, as well as a discussion of their implications for the future energy system.

The results indicate that dynamics between hydrogen and electricity are governed by short-term interactions. Electricity prices respond closely to renewable generation and demand, while hydrogen prices are less responsive to these factors. Instead, hydrogen price formation is more structurally determined, particularly by storage dynamics and cross-border trade. The strength of the relationship between the two markets is found to depend heavily on market situations: strong coupling occurs in situations with low residual load, when electrolysis is price-setting, while decoupling emerges under high residual load, when hydrogen storage discharge dominates price formation. Furthermore, driven by the consideration of LTCs and cross-border trade limitations, the electricity-to-hydrogen price ratio averages 0.56, which is lower than in prior sudies (0.7–1.2), which abstract from these characteristics. Scenario analysis shows that expansion of NTCs for hydrogen slightly weakens price coupling, with an exception in situations with high residual load where correlation of hydrogen and electricity prices increases. Demand reduction exerts only minor effects. Overall, the relationship between hydrogen and electricity prices remains consistent across configurations but sensitive to short-term system dynamics. Finally, the results suggest that relying solely on short-term price formation may not ensure cost recovery for hydrogen storage and electrolysis. In particular, LTC prices for hydrogen reflect both capital and operational costs, whereas the modeled short-term price formation is based on shadow prices. To adress this price discrepancy, capacity remuneration, cost mark-ups, or risk premiums may be needed to ensure investment viability and the development of a liquid market for hydrogen.

The paper is structured as follows: Section 2 describes the modeling approach and the system configurations investigated within this research. Section 3 analyzes the price formation of hydrogen as well as the relationship between hydrogen and electricity prices. Different sensitivities are used to check the robustness of the results. Section 4 addresses the broader implications of the findings regarding the future energy system, as well as their limitations. Finally, Section 5 summarizes and suggests directions for future research.

2. Methodology, input data and scenario design

This study investigates the fundamentals of hydrogen price formation and its relationship with electricity prices based on shadow prices. To this end, the European energy system model DIMENSION (Richter, 2011; Helgeson and Peter, 2020; Helgeson, 2024; Emelianova and Namockel, 2024) is employed and extended to derive daily prices for hydrogen from the respective equilibrium constraint, analogous to electricity. The shadow prices reflect the cost of supplying one additional unit of the corresponding energy carrier at a given point in time. Throughout the paper, the shadow prices are interpreted as prices under the condition of complete markets, perfect information, and perfect competition. In this context, strong duality, given linearity and a convex objective function, is assumed between the electricity and hydrogen markets in the integrated energy system model. Daily values for a full year serve as the basis for the empirical analysis, with a particular focus on short-term influences, such as weather variability and demand fluctuations, that shape the dynamics of hydrogen and electricity prices. Price formation mechanisms and the interrelationship between the two markets are assessed through co-integration, and correlation and regression analyses, complemented by a comparison of statistical properties. To capture heterogeneous market conditions, the data are segmented into subsets using a k-Means clustering algorithm, enabling a more granular examination of price interactions across different market situations. Next to a reference scenario, different system configurations are introduced to evaluate the robustness of the findings.
The following sections outline the model extensions and assumptions related to PtX fuels, with a particular focus on hydrogen (Section 2.1), and describe the system configurations investigated in this study (Section 2.2).

2.1. Modeling the equilibrium for hydrogen

The equilibrium constraint represents the central element of the model extension, as it determines the marginal generation costs for each fuel modeled. The constraint is formulated not only for hydrogen but also for other PtX-fuels such as diesel, gas, gasoline, kerosene, and oil, denoted as $f \in F$. This constraint applies across all countries within the model's scope, $b, b_1 \in B$, and considers external regions $r \in R$ as potential suppliers. Various technologies $a \in A$, including electrolysis and hydrogen storage, are considered alongside different sectors $s \in S$, each with distinct characteristics. The equilibrium ensures that, for each day $d \in D$, supply equals demand across all fuels, as described in Eq. (1). Throughout the study, the notations presented in Tables 8 to 10 in the Appendix are consistently used, with optimization variables distinguished from exogenous parameters by uppercase letters for the former. The formulation reflects an investment decision framework with reduced temporal granularity[2]. In dispatch simulations, selected variables (denoted by '*') are fixed to represent a given capital stock and long-term import decisions.

$$
\begin{aligned}
&PIPE^*(b,f)/365 + \sum_{r \in R} SHIP^*(r,b,f)/365 + \sum_{b_1 \in B} TRADE(d,b_1,b,f) + \sum_{h \in H}\sum_{a \in A} \frac{24}{H} * PROD(d,h,a,b,f) \\
&\geq \sum_{s \in S} USE(d,b,s,f) + \sum_{a \in A} INSTOR(d,b,a,f) + \sum_{b_1 \in B} TRADE(d,b,b_1,f) \quad \forall d \in D \wedge b \in B \wedge f \in F.
\end{aligned} \tag{1}
$$

On the supply side, imports are available via pipeline ($PIPE^*$) or ship ($SHIP^*$) from regions outside the model scope. Additionally, trade is possible with neighboring countries within the model scope, given that infrastructure exists between two countries. Domestic PtX production, such as electrolysis, is captured by $PROD$ with hourly resolution. On the demand side, consumption of PtX-fuels across various sectors is represented by USE [3]. For hydrogen, storage injection is separately represented as $INSTOR$. Similarly, trade is modeled on the demand side as well. In the subsequent sections, the fundamental characteristics of these supply and demand options are described in greater detail.

2.1.1. PROD - Domestic production of hydrogen

Domestic hydrogen production is performed using alkaline water electrolysis, with efficiencies ranging from 72% to 77%. The operation of electrolysis is fully market-oriented, with production quantities determined by market conditions. Additionally, the variable $PROD$ covers also the hydrogen supply by different types of hydrogen storage (see Section 2.1.5 for more details).

[2] Reduced temporal granularity refers to a representative subset of days (D) and hours (H) rather than a full year with hourly resolution.

[3] The term USE covers the exogenously defined hydrogen demand in end-use sectors such as industry, transport or buildings and also includes the endogenous fuel consumption in the energy sector.

2.1.2. SHIP - Hydrogen import via ship from non-EU regions

Imports via ship are modeled as long-term contracts (LTCs). The contract volume is a fixed parameter in the dispatch simulation, determined by an investment model run. The total amount of fuel imported from a specific exporting region $r \in R$ across all European countries is constrained by the export potential of that region, denoted as $ptxPotShip$ in $MWh_{th}/year$, as formulated in Eq. (2). Additionally, only countries with access to the ocean are eligible to import PtX-fuels via ships. These imports are restricted by the capacity of the import terminals, $ptxTerminal$, as described in Eq. (3). The associated import costs, represented by the variable $COSTS^{SHIP}$ in Eq. (4), are considered in the overall objective function of the energy system model.

$$\sum_{b} SHIP^{*}(r,b,f) \leq ptxPotShip(r,f) \quad \forall r \in R \wedge f \in F \tag{2}$$

$$\sum_{r} SHIP^{*}(r,b,f)/365 \leq ptxTerminal(b,f) \quad \forall b \in B \wedge f \in F \tag{3}$$

$$COSTS^{Ship} = \sum_{b \in B} \sum_{r \in R} \sum_{f \in F} SHIP^{*}(r,b,f) * ptxCostsShip(r,f) \tag{4}$$

The data for PtX imports via ship are sourced from the EWI Global PtX Cost Tool 2.0, which provides the potential and costs for various PtX fuels from multiple exporting regions (Klaas et al., 2024). The cost data represent the levelized cost of hydrogen, including both variable and investment costs. This encompasses the costs of hydrogen production as well as the infrastructure required for importation, such as terminals and conversion facilities. The supply cost function for hydrogen imports is illustrated in Appendix A. The supply curve relies on several key assumptions. The analysis assumes that exporting countries maintain a baseload supply profile throughout the year. Accordingly, the utilization of import terminals is assumed to remain constant across the entire modeling period. From each exporting region, only the cost of the cheapest production and transportation method is considered. The utilized potential for hydrogen production is assumed to be 20% of the technical potential. Only regions with a minimum production potential of 50 TWh$_{th}$ per year are included in the analysis. North Africa and Ukraine are excluded from the supply cost function, as these import options are modeled as bilateral imports via pipelines. For hydrogen imports, the parameter $ptxTerminal$ is fixed at 10,000 MWh$_{th}$ per day for countries with access to the global hydrogen market, defined as those having a coastal border.

2.1.3. PIPE - Hydrogen import via pipeline from non-EU regions

Pipeline imports are modeled via four distinct import routes as LTCs. Two of these routes originate in North Africa, connecting Spain and Italy via pipelines to this region. The other three routes originate in

Ukraine, with Hungary, Romania, and Slovakia acting as the importing countries through pipeline connections. According to Eq. (5), the selected import volume is endogenous but must not exceed the available potential. As indicated by the equilibrium constraint, the imports are evenly distributed throughout the year, assuming sufficient pipeline capacity. The import costs are computed by multiplying the imported volume by the associated cost, as defined in Eq. (6). Like imports via ship, pipeline imports in dispatch simulations are held constant according to the determined amount in the invest decision.

$$PIPE^{*}(b,f) \leq ptxPotPipe(b,f) \quad \forall b \in B \wedge f \in F \tag{5}$$

$$COSTS^{Pipe} = \sum_{b \in B} \sum_{f \in F} PIPE^{*}(b,f) * ptxCostsPipe(b,f) \tag{6}$$

Data from TYNDP 2024 (ENTSO-E and ENTSOG, 2024) are utilized to determine the import potential for both Ukraine and North Africa. Spain and Italy have an import potential of 331 TWh_{th} per year each. Ukraine's potential is distributed as follows: 55 TWh_{th} annually for Hungary, 63 TWh_{th} for Romania, and 114 TWh_{th} for Slovakia. Cost data are derived from the Global PtX Cost Tool 2.0 (Klaas et al., 2024), with an import price of 501.57 €/MWh_{th} from Ukraine and 202.26 €/MWh_{th} from North Africa.

2.1.4. TRADE - Hydrogen trade with neighboring countries

Cross-border hydrogen trade follows a NTC approach, analogous to electricity markets. The total traded volume ($TRADE$) cannot exceed NTC limits ($tradeCap$), as defined in Eq. (7).

$$TRADE(d,b_1,b,f) \leq tradeCap(b_1,b,f) \quad \forall d \in D \wedge b, b_1 \in B \wedge f \in F \tag{7}$$

Based on the TYNDP 2024 data (ENTSO-E and ENTSOG, 2024), an initial grid setup is established in the Reference Scenario, while a sensitivity explores a higher degree of interconnection (see Section 2.2). The interconnections involving Great Britain, Norway, and Switzerland are defined by custom assumptions. All NTC values are detailed in Appendix B.

2.1.5. Hydrogen storage

In comparison to all other PtX-fuels, storage is explicitly modeled only for hydrogen. The model incorporates four distinct types of hydrogen storage: reallocation of existing pore and cavern gas storage, as well as the construction of new pore and cavern storage facilities. Hydrogen storage technologies are formally defined as $a \in A^{H_2Stor}$, a subset of A.

The modeling of hydrogen storage follows principles similar to those used for electricity storage, but with additional detail to capture the diverse sources of hydrogen allocation. In addition to satisfying national hydrogen demand, hydrogen from domestic production, and imports via ships, pipelines, or trade can also be directed to storage. This allocation is reflected by the following Eqs. (8) to (11).

$$INSTOR^{Prod}(d,h,a,b,f) \leq PROD(d,h,a,b,f) \quad \forall h \in H \wedge d \in D \wedge a \in A \wedge b \in B \wedge f \in F \tag{8}$$

$$INSTOR^{Pipe}(d,b,f) \leq PIPE(b,f)/365 \quad \forall d \in D \wedge b \in B \wedge f \in F \tag{9}$$

$$INSTOR^{Ship}(d,r,b,f) \leq SHIP(r,b,f)/365 \quad \forall d \in D \wedge r \in R \wedge b \in B \wedge f \in F \tag{10}$$

$$INSTOR^{Trade}(d,b_1,b,f) \leq TRADE(d,b_1,b,f) \quad \forall d \in D \wedge b,b_1 \in B \wedge f \in F \tag{11}$$

The daily stored quantity of hydrogen (in MWh_{th}) is computed using Eq. (12) as the sum of contributions from all four sources.

$$\begin{aligned} \sum_{a \in A} INSTOR(d,b,a,f) = \sum_{h \in H} \sum_{a \in A} \frac{24}{H} * INSTOR^{Prod}(d,h,a,b,f) + INSTOR^{Pipe}(d,b,f) \\ + \sum_{r \in R} INSTOR^{Ship}(d,r,b,f) + \sum_{b_1 \in B} INSTOR^{Trade}(d,b_1,b,f) \quad \forall d \in D \wedge b,b_1 \in B \wedge a \in A^{H2Stor} \wedge f \in F \end{aligned} \tag{12}$$

The maximum storage withdrawal per day is constrained by the withdrawal speed in MWh_{th}/day. The speed depends on the installed storage capacity (in MWh_{th}), multiplied with an volume factor (in h), as expressed in Eq. (13). For all different hydrogen storage technologies, the ratio of capacity to volume is assumed to be 1:340 based on EWI (2024). Also, based on insights from EWI (2024), the ratio for the injection speed is set to 1:9. This reflects the observed characteristics of hydrogen storage systems, which exhibit more constant injection during surplus periods and faster withdrawal during peak load hours in the power sector.

$$\sum_{h \in H} \frac{24}{H} * PROD(d,h,b,a,f) \leq INSTCAP^{*}(a,b) * vol(a) \quad \forall d \in D \wedge b \in B \wedge a \in A^{H_2Stor} \wedge f \in F \tag{13}$$

$$INSTOR(d,b,a,f) \leq INSTCAP^{*}(a,b) * vol(a) * inject(a) \quad \forall d \in D \wedge b \in B \wedge a \in A^{H_2Stor} \wedge f \in F \tag{14}$$

At the beginning of the model period, Eq. (15) sets the initial storage level. The initial level equals half the capacity plus storage injection, adjusted for the storage efficiency (η), minus hydrogen supply to the grid.

The efficiency is assumed to be 93%, which is the average value for hydrogen storage given in Tsiklios et al. (2023).

$$\begin{aligned} LEVEL(d,a,b,f) = {} & INSTCAP^{*}(a,b) * vol(a) * 0.5 + INSTOR(d,b,a,f) * \eta(a) \\ & - \sum_{h \in H} \frac{24}{H} PROD(d,h,a,b,f) \quad \forall d = d1 \wedge a \in A^{H_2Stor} \wedge b \in B \wedge f \in F \end{aligned} \tag{15}$$

Throughout the model period, the storage level must remain below the maximum storage volume, as shown in Eq. (16).

$$LEVEL(d,a,b,f) \leq INSTCAP^{*}(a,b) * vol(a) \quad \forall d \in D \wedge a \in A^{H_2Stor} \wedge b \in B \wedge f \in F \tag{16}$$

The model ensures day-to-day continuity in storage levels through Eq. (17).

$$\begin{aligned} LEVEL(d+1,a,b,f) = {} & LEVEL(d,a,b,f) + \eta(a) * INSTOR(d+1,b,a,f) \\ & + \sum_{h \in H} \frac{24}{H} * PROD(d,h,a,b,f) \quad \forall d \in D \wedge a \in A^{H_2Stor} \wedge b \in B \wedge f \in F \end{aligned} \tag{17}$$

Finally, the annual storage balance is enforced to ensure no net gain or loss of hydrogen storage over the year, as described in Eq. (18).

$$\sum_{d \in D} [\eta(a) * INSTOR(d,b,a,f) - \sum_{h \in H} \frac{24}{H} * PROD(d,h,a,b,f)] = 0 \quad \forall a \in A^{H_2Stor} \wedge b \in B \wedge f \in F \tag{18}$$

2.1.6. USE - Sectoral hydrogen demand

Hydrogen demand varies across sectors such as energy, transport, buildings, and industry. In the transport, buildings, and industry sectors, hydrogen demand follows an exogenous profile: for transport and industry, the demand is flat, whereas for buildings, it is both seasonal and volatile due to heating and cooling needs. In the energy sector, hydrogen can be used in two main ways, with consumption patterns typically influenced by market conditions: for electricity generation and district heating through combined heat and power (CHP) systems. In the case of CHP, the heat supply must align with a fixed demand profile. Additionally, the production of other synthetic fuels is modeled using closed-system processes. In these processes, electricity is used to produce hydrogen, which is directly further transformed using CO_2.

2.2. Scenario design and related assumptions

With the presented model improvements, this study applies a two-step modeling approach to investigate short-term hydrogen and electricity price dynamics in a climate-neutral energy system in 2050. In the first step, a long-term investment optimization is used to generate feasible and policy-aligned energy system configurations. Alongside exogenous scenario specifications — such as minimum renewable capacities and trade infrastructure capacities — endogenous decisions, including LTCs for hydrogen, are optimized. Alternative system configurations are derived by varying key assumptions, namely the extent of cross-border hydrogen trade infrastructure, hydrogen demand, and their combination. In the second step, high-resolution dispatch simulations are carried out under the fixed system configurations from step one. This enables a detailed examination of short-term price formation, volatility, and market interactions. Shadow prices for electricity and hydrogen, derived from equilibrium constraints, serve as the basis for the subsequent analysis. Figure 1 illustrates the stepwise modeling approach. Discrepancies between Step I and Step II in terms of system outcomes and related shadow prices are discussed in Section 4.

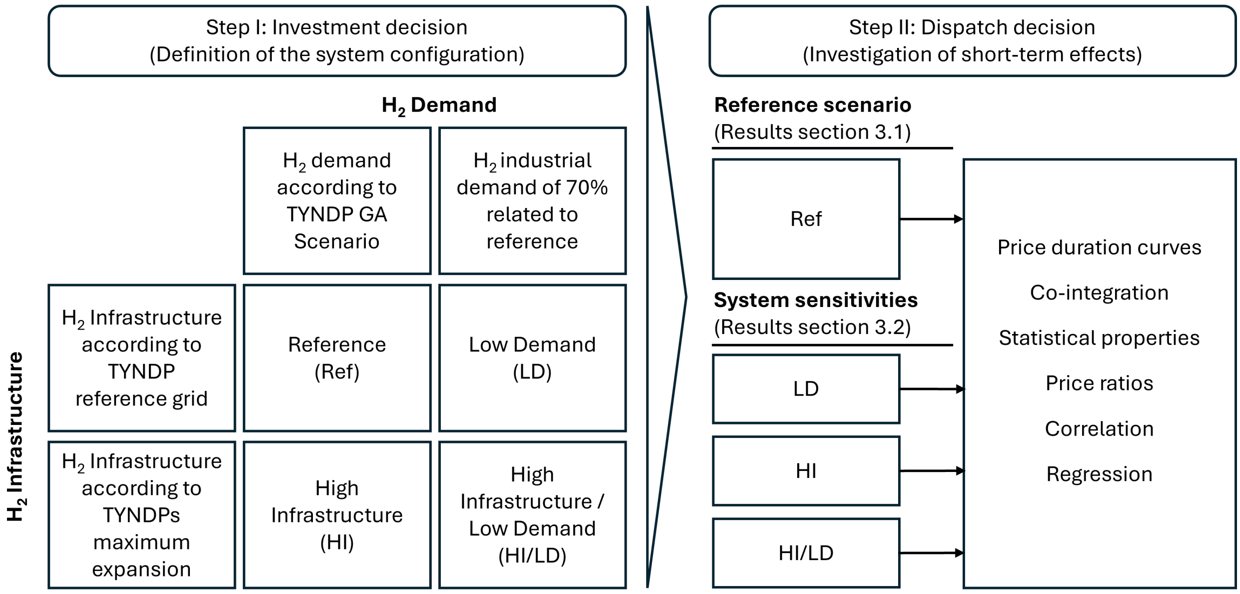

Figure 1: Overall model approach covering a reference scenario and three system sensitivities

The left side of the figure illustrates the different defined system configurations with variations in terms of infrastructure and demand. The names for the different sensitivities are displayed in the cells. The right side of the figure outlines the analysis conducted in the result sections, for both the base case and the system sensitivities, based on independent dispatch decision.

All scenarios incorporate capacity trajectories and minimum renewable energy targets in line with TYNDP 2024 (ENTSO-E and ENTSOG, 2024). Fuel prices are based on the "Stated Policies" scenario from IEA (2024), while hydrogen import prices via ship follow a supply cost curve provided in Appendix A. The

CO_2 price is endogenously derived via a cap-and-trade mechanism, assuming net-zero emissions by 2050. Electricity NTC values are sourced from the Global Ambition scenario of TYNDP 2024 (Appendix B). The sector- and fuel-specific energy demand for the reference scenario is likewise based on this scenario. Weather conditions are represented using a synthetic year with average full-load hours, following the "Trend Scenario" from the German EEG forecast (Netztransparenz, 2024).

Assumptions on hydrogen NTC values and industrial hydrogen demand vary across the four scenarios, leading to different invest decisions and thus different system configurations. In the reference scenario (*Ref*), NTC capacities for hydrogen reflect the reference grid of the TYNDP 2024. In the sensitivities *HI* and *HI/LD*, a more connected energy system is modeled by increasing the NTC values for hydrogen. The NTC values for the reference scenario and all sensitivities are detailed in Appendix B. In the sensitivities *LD* and *HI/LD*, the hydrogen demand in the industry sector is lowered by 30%, based on own assumption.

3. Results

The results are structured into two main parts to address the research objectives. First, the price formation for hydrogen and the relationship with electricity prices is investigated in the reference scenario, providing a baseline understanding of the underlying interdependence and dynamics (Section 3.1). Then, the robustness of these findings is tested by considering different system configurations (Section 3.2).

3.1. The relationship between electricity and hydrogen prices

The analysis of short-term effects on the structure of hydrogen and electricity prices, as well as their interrelationship, is conducted in several steps to ensure a comprehensive understanding of these dynamics. Following a description of the underlying system configuration (Section 3.1.1), the price duration curves and statistical properties for both energy carriers are first analyzed separately to identify their fundamental structures (Section 3.1.2). Then, the result of data segmentation into subsets reflecting distinct market situations is presented (Section 3.1.3). For each subset, the existence of co-integration is assessed (Section 3.1.4). Subsequently, the statistical properties of hydrogen and electricity prices are examined, by additionally considering electricity-to-hydrogen price ratios (Section 3.1.5). Finally, regression and correlation analyses are conducted within each subset to identify key drivers of price formation and to evaluate coupling and decoupling dynamics between the two markets (Section 3.1.6).

3.1.1. *System configuration*

The system configuration, based on the investment decision in Step I, forms the basis for the dispatch modeling and the further analysis. All installed capacities for Germany, determined in this step, are detailed in Appendix C. In the reference scenario, 55 TWh of hydrogen storage capacity and 76.5 GW of electrolysis capacity is built in Germany. Additionally, LTCs for hydrogen imports via ship and pipeline are endogenously selected in the investment run, resulting in 190.8 TWh of oversea hydrogen imports for Germany.

Based on these installed capacities and selected LTC imports, the dispatch decision (Step II) provides the detailed energy balances and corresponding shadow prices. The resulting sector-specific electricity and hydrogen demand is provided in Appendix D. Appendix E illustrates the daily hydrogen balance, while Appendix F presents the daily storage levels across Europe.

3.1.2. *Price formation and price duration curves*

To get an initial understanding of price formation and price structures, hydrogen and electricity prices are first analyzed separately. Figure 2 presents daily prices in both unsorted and sorted order, where the descending sorted order represents the price duration curve. In addition, Table 1 summarizes the corresponding statistical properties.

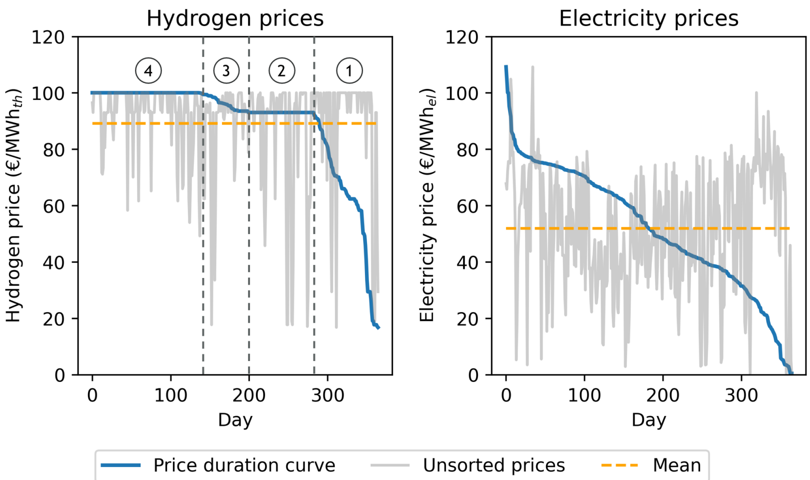

Figure 2: Price data and duration curves for hydrogen and electricity

The price data are shown for Germany. Hourly electricity prices are weighted by the corresponding demand to calculate daily prices. Both electricity and hydrogen prices represent the shadow prices of their respective equilibrium constraints.

Statistic	**H_2**	**EL**
Mean[1]	89.19	51.95
Median[1]	93.89	51.91
Std. dev.[1]	18.27	21.90
CV[2]	0.20	0.41
Minimum[1]	16.83	0.50
Maximum[1]	100.09	109.27

Table 1: Statistical summary of hydrogen and electricity prices

[1] in €/MWh; [2] no unit; CV is the coefficient of variation, which normalizes the standard deviation to the mean.

Price formation in both the hydrogen and electricity market is associated with a wide range of prices, each with distinct statistical characteristics.

One key factor driving the emergence of differntiated prices both for hydrogen and electricity lies in the hourly variability of electricity prices. In line with Böttger and Härtel (2022) and Antweiler and Muesgens (2025), diverse generation technologies — such as biogas, nuclear, gas, and biomass — and various flexibility options on both the supply and demand sides result in a broad spectrum of electricity price levels. Given that the hydrogen system interacts with the electricity system on a daily basis (analogous to the current methane system), hourly electricity prices are aggregated to volume-weighted daily values. In this process, factors such as the frequency of high and low prices throughout the day, along with the level of demand, significantly influence the resulting electricity price structure. As a result, a continuous price duration curve without distinct plateaus emerges for electricity. Prices experience high volatility with a coefficient of variation (CV) of 0.41 around a mean value of 51.95 €/MWh$_{el}$. The low mean is driven by 1122 hours of close-to-zero prices, and only a few hours with peak prices of around 145 €/MWh$_{el}$. Additionally, transmission constraints contribute to volatility, as evidenced by variations in mean electricity prices across countries[4].
In contrast, the hydrogen price duration curve, with a mean value of 89.19 €/MWh$_{th}$, lies substantially above that of electricity, primarily due to electrolysis and storage inefficiencies. The quantities and high prices for hydrogen imports from non-European countries are not part of the hydrogen price duration curve, as they are modeled as LTCs with quantities selected in the investment decision stage[5]. The structure of the price duration curve is defined by several distinct segments, shaped by the availability and operation of hydrogen storage next to the behavior of electrolysis. Hydrogen price convergence across countries indicates that the system does not face significant transmission grid limitations of cross-zonal trade[6]. Nevertheless, cross-border trade congestion can occur on single days.
The first segment in the hydrogen price duration curve exhibits a range of prices between 16.83 and 91.91 €/MWh$_{th}$, reflecting periods when storage charging capacity in Germany or exporting options are insufficient to align prices. In these situations, electrolyzers are price-setting, with hydrogen prices determined by electricity prices adjusted by the efficiency of the electrolyzer. Importantly, price-setting is not necessarily driven by local electricity prices. For example, if electricity prices diverge across countries due to transmission

[4] Average electricity prices across European countries range from 9.88 €/MWh$_{\mathrm{el}}$ in Denmark to 69.03 €/MWh$_{\mathrm{el}}$ in Slovakia. Price differentials between single countries, such as 4.15 €/MWh$_{\mathrm{el}}$ between Germany and France and 7.11 €/MWh$_{\mathrm{el}}$ between Germany and Poland, indicate the presence of specific transmission congestion.

[5] The dispatch model minimizes variable costs, excluding sunk and investment costs. In contrast, LTC quantities and prices are endogenously selected in the investment stage based on LCOH, which includes both capital and operational costs. This results in price discrepancies between the two optimization steps. Since short-term prices may not fully reflect investment costs, risk premiums and mark-ups may be necessary from investors' perspective (see Section 4 for further discussion on cost recovery).

[6] Mean values for hydrogen in other countries next to Germany are in the same magnitude, with a median value of 91.10 €/MWh$_{th}$. Denmark is the country with the lowest mean price of 53.79 €/MWh$_{th}$. Ireland, Great Britain, Spain and Portugal instead face prices above 100 €/MWh$_{th}$, mainly driven by limited trade capacities with other countries (see Appendix B).

congestion, but hydrogen trade remains unconstrained, electrolyzers in different regions may still determine local hydrogen prices based on diverging electricity price levels. The second segment is marked by a price plateau at 93.08 €/MWh$_{th}$, during which storage charges at partial capacity. Here, the availability of storage and trade enables temporal and regional balancing, making storage the price-setting technology. In the third segment, hydrogen storage in Germany is neither charging nor discharging and demand is met through domestic electrolysis or imports from neighboring countries. As in the first segment, electrolyzers determine the hydrogen price. Despite the market-oriented operation of electrolyzers with moderate annual average full load hours (3,215 h/a), domestic hydrogen production is even maintained in situations of elevated electricity prices. This results in relatively high hydrogen prices within the price duration curve. The final segment reveals a second price plateau, corresponding to periods of storage discharge. The difference between the two pronounced plateaus reflects the storage efficiency of 93%.

Overall, price formation in the hydrogen market is linked to those in the electricity market by electrolysis, with hydrogen storage occurring as the price-setting technology in certain situations. Cross-border trade results in prices linkages between both markets across countries. Additionally, hydrogen prices exhibit lower volatility than electricity prices, as reflected in both the standard deviation and CV, indicating limited technological heterogeneity and the pronounced stabilizing effect of storage and trade.

Electricity price formation, in turn, is further influenced by its bidirectional dependence on the hydrogen market. Hydrogen shadow prices affect the costs of hydrogen-based electricity generation and heat production via CHP, which, in turn, influence electricity market outcomes. This mutual dependency creates a dynamic pricing environment where the situation in both markets directly impacts price-setting in the other.

To explore these interdependencies in greater detail, the following sections systematically examine the relationship between hydrogen and electricity prices by considering different market situations.

3.1.3. Data separation

The dataset of daily price pairs is segmented into four distinct subsets, each representing a specific combination of electricity and hydrogen market conditions. This classification enables a more granular analysis of price dependencies and variations in statistical properties. A k-Means clustering algorithm is applied using two key dimensions. The first dimension captures electricity market conditions, represented by electrical residual load (RL). The second dimension characterizes the hydrogen market using hydrogen residual load as a proxy. Hydrogen residual load is derived by subtracting the constant hydrogen import via ship from the exogenous demand profile across the transport, buildings, and industry sectors. The clustering algorithm systematically assigns price pairs to one of four distinct market conditions, categorized by combinations of high or low electrical residual load and high or low hydrogen residual load:

- High electrical residual load / High hydrogen residual load (*El. high RL / H_2 high RL*)
- High electrical residual load / Low hydrogen residual load (*El. high RL / H_2 low RL*)
- Low electrical residual load / High hydrogen residual load (*El. low RL / H_2 high RL*)
- Low electrical residual load / Low hydrogen residual load (*El. low RL / H_2 low RL*)

Figure 3 visualizes this separation of price data. The appendix G provides additional visualization of the hydrogen supply and demand mix in each subset together with the corresponding electrical residual load.

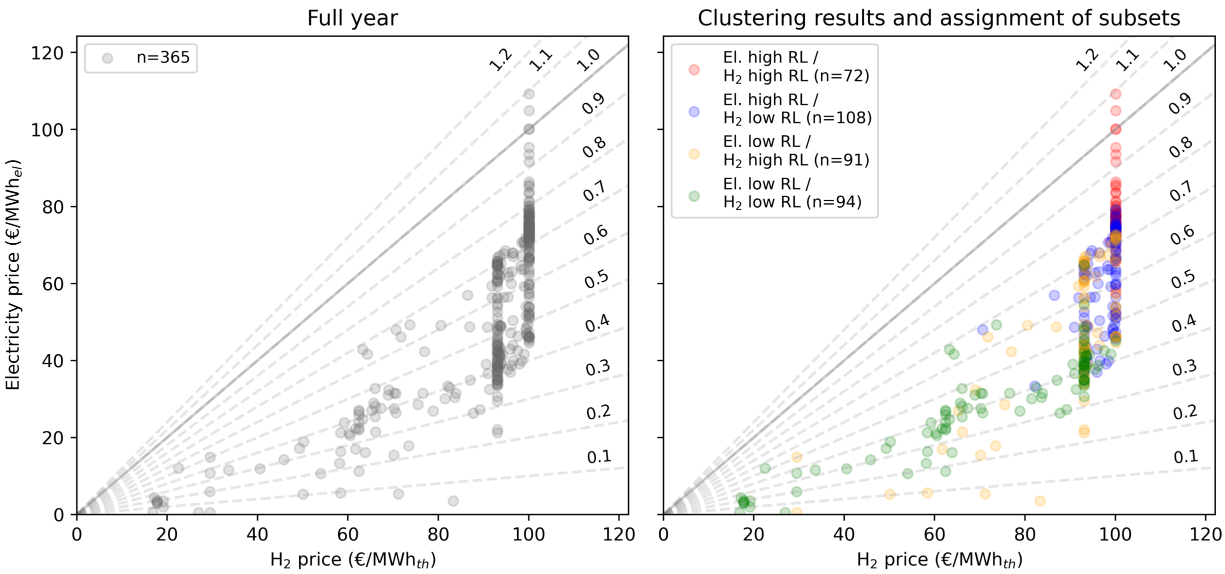

Figure 3: Daily pairs of electricity and hydrogen prices split in four subsets

Gray dots represent the entire year (365 data points). Colored dots indicate data points belonging to one of the four market condition clusters. Hourly electricity prices are weighted by demand to calculate daily averages. Both electricity and hydrogen prices represent the shadow prices of their respective equilibrium constraints.

3.1.4. Analysis of co-integration

The segmentation of price data into distinct market conditions raises the question of whether hydrogen and electricity prices exhibit co-integration within specific subsets. Co-integration would suggest that the two price series share a long-term equilibrium relationship despite short-term fluctuations. To assess this, an Augmented Dickey-Fuller (ADF) test is conducted on both the hydrogen and electricity price time series (see Appendix H for the details). The results reject the presence of a unit root for both series, indicating that hydrogen and electricity prices are stationary. Since stationarity is a necessary condition for co-integration, this confirms that hydrogen and electricity prices do not share a long-term equilibrium relationship. Instead, their relationship is primarily governed by short-term interactions, influenced by fluctuations in residual loads, storage dynamics, and market conditions. This result supports the use of correlation analysis and regression models to examine price dependencies, rather than co-integration models, which are typically suited for non-stationary series.

To explore these short-term dependencies in greater detail, the next section presents the statistical properties for the full dataset and for each subsets, followed by a regression analysis with the same distinction.

3.1.5. Analysis of statistical properties

This section analyzes and compares the statistical properties of hydrogen and electricity prices over the full year and across the four subsets. To establish an initial understanding of the differences between subsets and the price characteristics within each, Table 2 presents a summary of key statistical indicators, including mean, median, standard deviation, coefficient of variation, and the minimum and maximum values.

Table 2: Statistical summary of hydrogen and electricity prices

Statistic	**Full year**		**El. high RL H_2 high RL**		**El. high RL H_2 low RL**		**El. low RL H_2 high RL**		**El. low RL H_2 low RL**	
	H_2	**EL**	**H_2**	**EL**	**H_2**	**EL**	**H_2**	**EL**	**H_2**	**EL**
Mean[1]	89.19	51.95	100.07	77.32	97.13	59.64	89.71	46.68	71.23	28.77
Median[1]	93.89	51.91	100.09	75.51	99.46	62.44	93.08	46.16	75.14	31.20
Std. dev.[1]	18.27	21.90	0.14	9.22	4.30	12.22	13.62	18.05	24.69	13.58
CV[2]	0.20	0.42	0.00	0.12	0.04	0.20	0.15	0.39	0.35	0.47
Minimum[1]	16.83	0.50	98.88	52.49	70.62	33.35	29.47	0.50	16.83	0.50
Maximum[1]	100.09	109.27	100.09	109.27	100.09	79.30	100.09	72.73	100.09	64.75

[1] in €/MWh; [2] no unit; CV is the coefficient of variation, which normalizes the standard deviation to the mean.

The subset analysis reveals distinct price formation behaviors under different residual load conditions. Electrical residual load, which varies widely between negative and positive values (standard deviation: 0.39), exerts a stronger influence on price variation across subsets than hydrogen residual load, which remains strictly positive with limited variability (standard deviation: 0.06). Nonetheless, differences between high and low hydrogen residual load subsets are also pronounced. This is due to the characteristic that high residual load conditions typically correlate with situations with additional hydrogen demand in the power and heating sectors, while low residual load coincides with increased hydrogen production during periods of surplus renewable electricity feed-in. These dynamics reinforce intra-annual price differentiation.

Across subsets, high hydrogen residual load results in elevated and stable hydrogen prices, reflecting limited flexibility and the reliance on storage discharge or imports. In contrast, low hydrogen residual load is associated with greater price dispersion and volatility, as electrolysis becomes the dominant price-setting technology. Similarly, high electrical residual load is associated with higher and more stable prices for both energy carriers, whereas low electrical residual load coincides with lower and more volatile prices, particularly pronounced for hydrogen.

Price levels and volatility are predominantly governed by the ability of the system to respond dynamically to short-term supply and demand fluctuations. Storage operation emerges as a key determinant of hydrogen price formation, with its charging and discharging behavior moderating or amplifying price movements depending on residual load conditions within the different subsets.

Looking at specific market situations in detail reveals that market conditions with high electrical residual load and high hydrogen residual load exhibit the highest mean prices for both energy carriers. Hydrogen prices in this subset are highly stable (CV = 0.00), reflecting minor sensitivity to residual load fluctuations and storage discharging behavior as the dominant price-setting mechanism. While electricity prices in this subset are also on a high level, their higher, but moderate CV of 0.12 indicates greater short-term variability, influenced by demand fluctuations and renewable generation variations.

When electrical residual load is high, but hydrogen residual load is low, price variability for both carriers is also low, though prices and the underlying price formation characteristics in this subset are more heterogeneous. Storage discharging, associated with hydrogen price alignment, can be observed in 13% of the days within the subset. This subset also covers days when storage is charging (15%) or when storage is in a neutral position (72%) in Germany. Notably, despite storage is neither charging nor discharging domestically, storage behavior in neighboring countries can affect domestic price formation, provided sufficient trade capacity is available. Thus, in this cluster, all price-setting mechanisms — electrolyzers, storage charging, and storage discharging — are present, but most of the price prices reflect price-setting by electrolyzers at the upper end of the residual load duration curve. These dynamics support the finding that elevated electrical residual load drives hydrogen demand, particularly in the power sector, despite hydrogen residual load is low.

In contrast, low electrical residual load combined with high hydrogen residual load leads to decreasing price of both hydrogen and electricity. In this subset, hydrogen storage is predominantly charging or inactive, with full charging observed on approximately 26 out of 91 days. These 26 days face demand-side flexibility constraints, driven by increased renewable feed-in and corresponding domestic hydrogen production, which lowers prices. However, elevated hydrogen residual load in this subset limits further price reductions. Finally, when both residual loads are low, price levels for both hydrogen and electricity are the lowest across subsets. Hydrogen storage is actively charging, often at full capacity, contributing to downward price movements. Electrolysis determines price-formation of hydrogen prices, with price levels linked to those for electricity. Additionally, due to constrained storage charging capacity, this subset exhibits the highest price volatility for hydrogen (CV = 0.35) and comparably high volatility for electricity, indicating price movements driven by fluctuating residual load.

Electricity-to-hydrogen price ratios

Beyond the statistical properties of hydrogen and electricity prices, the distribution of daily electricity-to-hydrogen price ratios across the year and within the different subsets are examined in greater detail. The ratios serve as a valuable indicator for policymakers, investors and researchers when evaluating the energy system and different decarbonization options, or calculating the profitability of assets such as electrolyzers, without necessarily running energy system models. Table 3 illustrates the properties of the distribution of price ratios.

Table 3: Statistic on the distribution of daily electricity-to-hydrogen price ratios

Statistic	**Full year**	**El. high RL H_2 high RL**	**El. high RL H_2 low RL**	**El. low RL H_2 high RL**	**El. low RL H_2 low RL**
Maximum	1.09	1.09	0.79	0.73	0.70
3^{rd} quartile	0.72	0.79	0.71	0.65	0.43
Median	0.56	0.75	0.66	0.49	0.39
1^{st} quartile	0.41	0.73	0.52	0.41	0.35
Minimum	0.02	0.52	0.39	0.02	0.02

The statistics in price ratios reflect the distribution of daily values from the perspective of the hydrogen market in daily resolution. 50% of the data are located between the first and third quartiles. Due to the aggregation from hourly electricity prices, values may differ when analyzed from the electricity market perspective using higher temporal resolution.

Over the full year, the median electricity-to-hydrogen price ratio is 0.56, reflecting inherent electrolysis conversion losses and the structural cost differential between electricity and hydrogen, especially under conditions where hydrogen storage is price-setting or cross-border trade is constrained. Daily price ratios range from 0.02 to 1.09, with a moderate interquartile range[7] (IQR) of 0.31, indicating that there are only a few situations across the year, where hydrogen and electricity prices either diverge or are closely aligned.

[7]The interquartile range reflects the difference between the third and the first quartile of the data set.

A comparison of the subset-specific results reveals that electricity market conditions significantly influence the electricity-to-hydrogen price ratio. In particular, high electrical residual load conditions tend to correspond with higher price ratios. Price ratios are highest in situations with high residual load in both markets, and lowest when hydrogen production benefits from surplus renewable feed-in while demand remains moderate.

In situations with both high electrical residual load and high hydrogen residual load (*El. high RL / H_2 high RL*), the electricity-to-hydrogen price ratio is high (0.75) with low variability, as the IQR is only 0.06. This pattern reinforces the observation that both prices tend to be high and stable when residual load increases for both electricity and hydrogen.

When hydrogen residual load is low but electrical residual load remains high (*El. high RL / H_2 low RL*) improved supply-side flexibility allows electrolyzers to more frequently set hydrogen prices, while persistently high electricity prices lead to an elevated ratio. Variability of the price ratio within this subset is comparatively low, again indicating relatively stable price relationships.

Conversely, under low electrical residual load with high hydrogen residual load, the price ratio is smaller, exhibiting the largest variability (IQR = 0.24) due to heterogeneous storage behaviors and volatile prices.

Finally, the lowest ratio of 0.39 occurs when both residual loads are low. This low ratio is partly explained by pronounced cross-border transmission congestion in electricity markets relative to hydrogen markets. As detailed in Section 3.1.2, electricity prices vary across countries, whereas hydrogen prices remain more aligned. Electrolyzers operating in regions with higher electricity prices and unconstrained hydrogen trade tend to elevate local hydrogen prices above German levels. The inverse applies when neighboring countries exhibit lower electricity prices and unrestricted hydrogen flows. Nevertheless, the observed price ratios suggest the former situation dominates in this subset.

3.1.6. Analysis of coupling and decoupling dynamics

To analyze the relationship between hydrogen and electricity prices in greater detail, correlation and regression analyses are applied to the full dataset and four distinct market subsets. This enables a more granular understanding of price dependencies under varying system conditions.

Table 4 presents the correlation coefficients alongside the results of two regression models. These models explain electricity and hydrogen price formation as functions of renewable generation, inelastic electricity demand, and hydrogen residual load. The regression results reveal structural characteristics in price formation across the year, and distinct coupling and decoupling dynamics when analyzing the different subsets.

Table 4: Regression and correlation results

	Full year		El. high RL H_2 high RL		El. high RL H_2 low RL		El. low RL H_2 high RL		El. low RL H_2 low RL	
Direct interaction between electricity and hydrogen price										
Coefficient of correlation	0.77		0.08		0.45		0.70		0.90	
Explanation of electricity prices										
Regression model 1: $Price_{el} = \alpha + \beta * RES + \gamma * Load_{el} + \delta * Residualload_{H_2} + \epsilon$										
intercept (α)	0.25		23.83		18.13		-52.00		7.35	
renewable generation coefficient (β)	-21.12	**	-14.95	**	-22.11	**	-25.96	**	-26.93	**
electrical load coefficient (γ)	31.23	**	15.34	**	31.96	**	38.78	**	35.79	**
hydrogen residual load coefficient (δ)	0.04	**	0.04	*	0.02		0.09	*	0.04	*
R^2	0.85		0.65		0.57		0.71		0.78	
Explanation of hydrogen prices										
Regression model 2: $Price_{H_2} = \alpha + \beta * RES + \gamma * Load_{el} + \delta * Residualload_{H_2} + \epsilon$										
intercept (α)	69.86	**	99.89	**	74.79	**	70.94	*	84.85	*
renewable generation coefficient (β)	-13.29	**	-0.05		-5.59	**	-16.11	**	-46.55	**
electrical load coefficient (γ)	25.54	**	0.13		6.81	**	26.30	**	71.05	**
hydrogen residual load coefficient (δ)	0.00		0.00		0.02	*	0.01		-0.01	
R^2	0.49		0.05		0.32		0.46		0.75	

Significance levels: ** p-value<0.01; * p-value<0.1.
The hydrogen residual load is calculated by subtracting the constant hydrogen import via ship from the exogenous demand profile in the end-use sectors. Electrical load equals the sum of the exogenous demand profiles in the end-use sectors.

Full-year relationships

The full-year regression and correlation results indicate a moderate degree of coupling between hydrogen and electricity markets. The correlation coefficient of 0.77 suggests that, on average, price movements in one market are partly reflected in the other. However, the underlying price drivers differ.

Electricity prices (Regression model 1) are primarily driven by supply and demand dynamics in the power sector. The strong negative impact of renewable generation ($\beta = -21.12$) reflects the well-documented merit-order effect, where higher renewable availability reduces electricity prices. Conversely, the coefficient for electrical load ($\gamma = 31.23$) highlights demand-driven price fluctuations. The hydrogen residual load also contributes significantly, although the effect is small in magnitude ($\delta = 0.04$). The high explanatory power ($R^2 = 0.85$) indicates that all three factors explain nearly all variation in electricity prices.

Hydrogen prices (Regression model 2) are less reflected by system dynamics, as indicated by the significance of the intercept. Additionally, the coefficient for hydrogen residual load is not statistically significant in the full-year model or in most of the subsets, again reflecting limited responsiveness. Renewable generation ($\beta = -13.29$) and electrical load ($\gamma = 25.54$) are significant, indicating that electricity market conditions influence hydrogen price formation through their effect on electrolysis costs. Nevertheless, the lower explanatory power ($R^2 = 0.49$) suggests that hydrogen price dynamics are only partially captured by these variables, reflecting additional, uncovered structural effects.

Coupling and decoupling dynamics

The subset analysis reveals that the strength of price coupling between hydrogen and electricity varies substantially depending on residual load conditions. Electricity prices are highly responsive to short-term fluctuations in supply and demand, while hydrogen prices exhibit more structural characteristics driven by the interplay between storage, electrolysis, and imports/exports. Strong price coupling of hydrogen and electricity prices occurs only in flexible, electrolysis-dominated regimes with low residual loads. In contrast, high residual load conditions lead to decoupling of prices, as structural constraints outweigh linkage of prices. Looking at the subsets in more detail reveals that in the subset with low residual load for both hydrogen and electricity (*El. low RL / H_2 low RL*), coupling is strongest. The coefficient of correlation reaches 0.90, the highest among all subsets. The high value confirms that price formation in this subset is largely governed by shared cost drivers, particularly renewable availability and electrical load. Regression model 1 even indicates that next to these two drivers, electricity prices are explained by hydrogen residual load, with a slightly significant coefficient. In general, strong coupling in this subset can be attributed to hydrogen production via electrolysis, which directly links its cost to electricity prices.

In subsets with asymmetric residual load conditions — either high hydrogen or high electricity residual load (*El. low RL / H_2 high RL* and *El. high RL / H_2 low RL*) - the strength of coupling declines to moderate levels. Correlation coefficients are 0.70 and 0.45, respectively, and the explanatory power of regression model 2 declines (R^2 = 0.46 and 0.32). These lower values reflect the role of hydrogen storage and cross-border trade, which partially decouple hydrogen price formation from short-term electricity price movements. Notably, coupling remains stronger in the subset with low electrical residual load, underscoring the dominate role of electrical residual load in influencing price coupling. As coupling declines, the intercept in the hydrogen price regression becomes significant — especially in the *El. high RL / H_2 low RL* subset — indicating a shift from market-based to fixed determinants of price formation.

When both residual loads are high (*El. high RL / H_2 high RL*), the relationship between hydrogen and electricity prices weakens significantly, leading to decoupling of price dynamics. The correlation coefficient drops to 0.08, and model 2 explains only 5% of the variation in hydrogen prices. While electricity prices remain sensitive to system dynamics (R^2 = 0.65), hydrogen prices are increasingly governed by storage discharge. The lack of statistically significant coefficients beyond the intercept in the hydrogen model confirms the structural decoupling of price dynamics between the two markets in this subset.

3.2. *Impact of the system configurations on the relationship between electricity and hydrogen prices*

This section investigates how different energy system configurations affect price formation and the relationship between electricity and hydrogen prices. Three sensitivities are analyzed to test the robustness of the results: a scenario with expanded cross-border hydrogen trade infrastructure (*HI*), one with reduced industrial hydrogen demand (*LD*), and a combined scenario incorporating both assumptions (*HI/LD*). Section 3.2.1 outlines the key structural changes in energy system configuration resulting from the altered assumptions. Section 3.2.2 examines the corresponding shifts in statistical properties, including changes in electricity-to-hydrogen price ratios. Section 3.2.3 then evaluates how the system sensitivities affect the price formation characteristics, as well as the coupling and decoupling dynamics between hydrogen and electricity prices.

3.2.1. *Changes in system configurations and derived price data*

The expansion of hydrogen trade capacities reduces constraints in cross-border hydrogen flows. Similarly, lower hydrogen demand relaxes supply requirements. These changes result in deviating energy system configurations, determined endogenously in the investment stage, which subsequently affects the dispatch decision outcomes (see Appendix C to F). The most pronounced effects are observed in the volume of hydrogen imports and installed storage capacities. While the *HI* scenario leads to a reduction in hydrogen storage capacity in Germany and across Europe, the *LD* scenario increases storage capacity domestically, with European capacity remaining close to the reference scenario. The combination of both changes (*HI/LD*) results in the lowest import volumes and storage capacities across the four scenarios.

Each sensitivity provides a new set of hydrogen and electricity price data. These form the basis of the respective price duration curves (Appendix I). While the four structural segments observed in the reference scenario remain present, their size and level shift slightly.

Price pairs in each sensitivity are again assigned to four clusters based on residual load characteristics, using the same k-Means algorithm as before. Figure 4 shows the resulting classification.

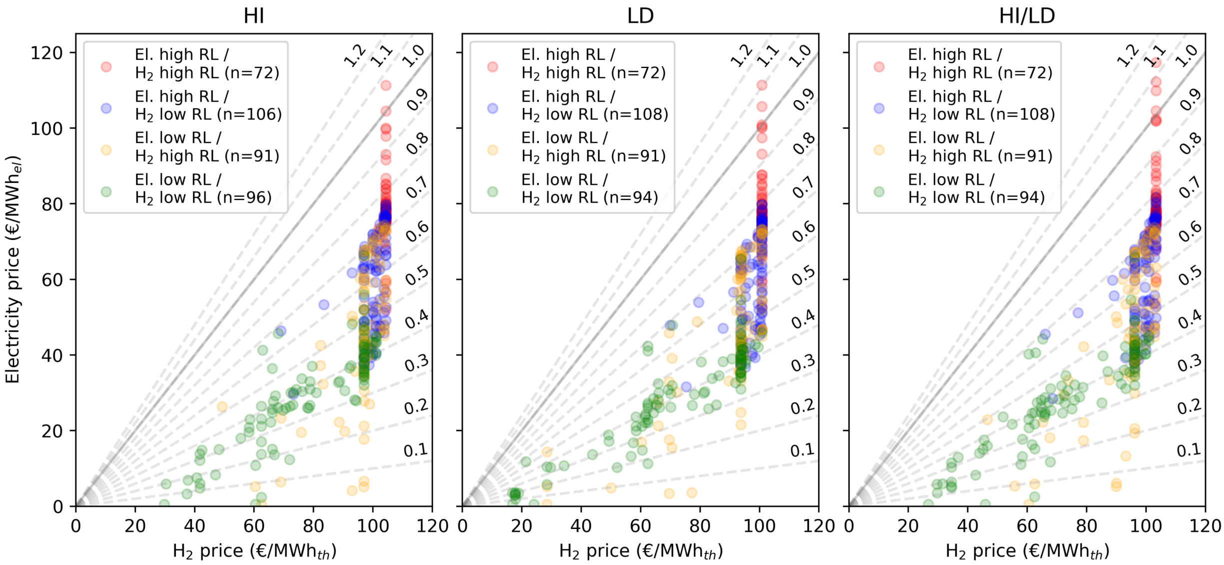

Figure 4: Electricity and hydrogen price pairs split in four subsets for the three system sensitivities

Each column represents one system sensitivity. Daily prices are assigned to one of the four clusters, representing different residual loads conditions. The daily electricity prices are weighted by hourly demand. Both electricity and hydrogen prices represent the shadow prices of their respective equilibrium constraints.

While the cluster assignments provide an initial intuition, the following sections analyze statistical properties and coupling mechanisms in greater depth to evaluate the robustness of the former findings.

3.2.2. Analysis of changes in statistical properties and price ratios

The changes of statistical properties of hydrogen and electricity prices across the full year and the four subsets under different system configurations are summarized in Table 5. These properties include the mean, median, standard deviation, coefficient of variation, and the range (minimum and maximum values) for each system scenario.

Overall, the statistical properties remain robust. While changes in corss-border hydrogen trade infrastructure and demand influence price levels and volatility to some extent, the overall price patterns and segment structures remain the same. The largest deviations from the reference scenario occur in the *HI* scenario, reflecting increased flexibility in terms of cross-border trade. By contrast, the *LD* scenario induces only minor changes, as lower hydrogen demand is largely offset by reduced hydrogen imports. The combined scenario (*HI/LD*) mirrors the effects of the *HI* case but with slightly diminished intensity, suggesting that variations in cross-border trade infrastructure have a greater impact on price characteristics than demand-side adjustments.

Table 5: Statistical summary of hydrogen and electricity prices for the system sensitivities

Statistic	System	Full year		El. high RL H$_2$ high RL		El. high RL H$_2$ low RL		El. low RL H$_2$ high RL		El. low RL H$_2$ low RL	
		H$_2$	EL	H$_2$	EL	H$_2$	EL	H$_2$	EL	H$_2$	EL
Mean[1]	Ref	89.19	51.95	100.07	77.32	97.13	59.64	89.71	46.68	71.23	28.77
	HI	4.87	0.54	4.10	1.06	3.03	0.33	6.32	0.52	6.64	1.05
	LD	0.02	0.35	0.68	0.93	0.34	0.26	-0.05	0.48	-0.77	-0.09
	HI/LD	2.63	0.85	3.12	2.42	1.68	0.67	4.23	0.75	1.81	-0.02
Median[1]	Ref	93.89	51.91	100.09	75.51	99.46	62.44	93.08	46.16	75.14	31.20
	HI	6.00	0.07	4.24	1.64	1.52	0.35	3.95	0.62	3.60	-0.27
	LD	1.33	0.42	0.67	0.70	0.06	0.16	0.63	0.47	-4.47	-1.06
	HI/LD	4.48	0.85	3.28	1.54	0.48	0.53	3.05	0.97	-2.96	-2.18
Std. dev.[1]	Ref	18.27	21.90	0.14	9.22	4.30	12.22	13.62	18.05	24.69	13.58
	HI	-2.80	0.20	0.33	0.06	0.87	0.61	-3.92	0.46	-4.52	-0.14
	LD	0.83	0.36	0.02	0.35	0.65	0.23	1.68	0.16	0.42	0.15
	HI/LD	-1.16	0.88	0.38	1.80	1.49	0.60	-2.62	0.29	-3.03	-0.15
CV[2]	Ref	0.20	0.42	0.00	0.12	0.04	0.20	0.15	0.39	0.35	0.47
	HI	-0.04	0.00	0.00	0.00	0.01	0.01	-0.05	0.00	-0.09	-0.02
	LD	0.01	0.01	0.00	0.00	0.01	0.01	0.02	0.00	0.01	0.01
	HI/LD	-0.01	0.01	0.00	0.02	0.02	0.01	-0.03	0.00	-0.05	0.00
Minimum[1]	Ref	16.83	0.50	98.88	52.49	70.62	33.35	29.47	0.50	16.83	0.50
	HI	12.93	0.00	3.09	-0.55	-1.63	-3.71	19.80	0.00	12.93	0.00
	LD	0.00	0.00	0.52	0.54	-0.71	-1.78	-1.01	0.00	0.00	0.00
	HI/LD	9.89	0.00	2.05	1.09	-4.53	-4.85	17.10	0.00	9.89	0.00
Maximum[1]	Ref	100.09	109.27	100.09	109.27	100.09	79.30	100.09	72.73	100.09	64.75
	HI	4.24	2.03	4.24	2.03	4.24	0.55	4.24	1.72	0.96	1.59
	LD	0.68	2.09	0.67	2.09	0.68	0.54	0.68	0.56	0.67	0.57
	HI/LD	3.28	8.11	3.28	8.11	3.28	2.42	3.28	1.06	0.84	1.14

Colorscheme to visualize deviations in percent from the reference scenario

-100%	-80%	-60%	-40%	-20%	0%	+20%	+40%	+60%	+80%	>+100%

[1] in €/MWh. [2] no unit. The values for the reference scenario are absolute numbers. The numbers for the three sensitivities are the deviations from the reference. The color scheme visualizes the deviation in percent with a dark red corresponding to deviations up to -100% and a dark green with deviations above 100% and higher.

In more detail, expanded corss-border hydrogen trade infrastructure increases mean hydrogen prices across the year and all subsets. This is primarily due to the alignment of domestic prices with previously higher-price neighboring countries, now connected through expanded trade capacity. The CV declines slightly for the full year, but diverges across subsets: volatility decreases under low electrical residual load and increases under high electrical residual load conditions. The number of days when storage discharge sets hydrogen prices declines substantially (from 78 to 45), while price-setting by electrolysis becomes more frequent, increasing price diversity. In subsets with low electrical residual load, more trade capacity mitigates storage and trade constraints, promoting price convergence. The expansion of cross-border hydrogen trade infrastructure also results in higher electricity prices throughout the year and across subsets, which correlates with the characteristics observed in the hydrogen market.

Reducing industrial hydrogen demand by 83.8 TWh_{th} does not significantly affect mean hydrogen prices, but slightly increases volatility. As hydrogen imports decline by 90.0 TWh_{th}, the share of baseload supply decreases, leading to a rising relative influence of more volatile hydrogen residual load. This amplifies price volatility, since European storage capacity remains largely unchanged.

The combined scenario reflects a mixture of the two individual sensitivities. Overall, the effect of the *HI* outweighs the effect of the *LD* scenario, but effects are weaker compared to the *HI* sensitivity alone regarding the full year characteristics. An exception is observed in the subset *El. low RL / H_2 low RL*, where median hydrogen prices slightly decline. In subsets with high electrical residual load, volatility increases more noticeably than in the *HI* scenario, although differences remain minor.

Electricity-to-hydrogen price ratio

As in the reference scenario, the electricity-to-hydrogen price ratios serve as a key indicator of the economic linkage between both markets, with its robustness of particular interest. Figure 5 illustrates how the distribution of daily price ratios emerges under different system configurations, driven by variations in cross-border hydrogen trade infrastructure and demand.

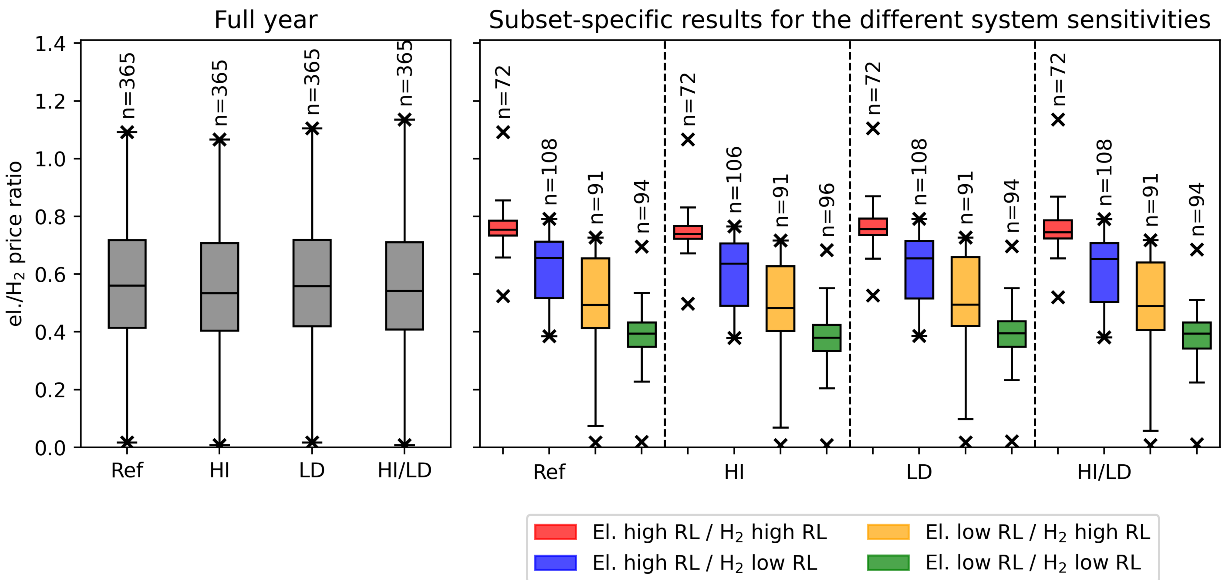

Figure 5: Distribution of the daily electricity-to-hydrogen price ratio for different system sensitivities and subsets

The gray bars reflect the entire year with 365 data points. The colored bars refer to one of the four subsets. The minimum and maximum values are represented by crosses. The median is depicted by the black line, while the colored box between the lower and upper quantiles represents 50% of all values. The maximum whiskers are equal or lower to 1.5 times the Inter-Quartile Range (range of the colored box). The statistics in price ratios reflect the distribution of daily values from the perspective of the hydrogen market. Due to the aggregation from hourly electricity prices, maximum values may differ when analyzed from the electricity market perspective using higher temporal resolution.

Overall, the distribution of electricity-to-hydrogen price ratios remains stable across the different system sensitivities. This finding reinforces the conclusion that the fundamental price relationship between hydrogen and electricity remains unaffected.

In the *HI* scenario, the electricity-to-hydrogen price ratio decreases slightly both on an annual average and within all subsets. This decline is primarily due to a stronger increase in hydrogen prices relative to electricity prices. As discussed in Section 3.2.2, hydrogen price alignment with previously higher-price neighboring regions drives this increase. As a consequence, enhanced cross-border trade reduces the cost advantage that domestic electrolysis had during periods of low electricity prices.

The *LD* and *HI/LD* scenarios both have a minimal impact on the electricity-to-hydrogen price ratio. The mean hydrogen and electricity prices remain roughly stable throughout the year, showing only minor deviations. Within the subsets, mean hydrogen and electricity prices move in the same direction relative to the reference scenario, resulting in a largely unchanged price ratio (see Table 5).

3.2.3. Analysis of changes in coupling and decoupling dynamics

Finally, to assess the robustness of the interdependencies between hydrogen and electricity prices, a correlation and regression analysis is conducted again across the various system sensitivities. Table 6 presents the correlation coefficients alongside the results of two regression models.

Table 6: Regression results and correlation for the system sensitivities *HI*, *LD*, and *HI/LD*

		Full year	**El. high RL H_2 high RL**	**El. high RL H_2 low RL**	**El. low RL H_2 high RL**	**El. low RL H_2 low RL**
Direct interaction between electricity and hydrogen price						
coeficcient of correlation	Ref	0.77	0.08	0.45	0.70	0.90
	HI	0.75	0.20	0.44	0.61	0.86
	LD	0.78	0.08	0.46	0.73	0.90
	HI/LD	0.77	0.25	0.48	0.67	0.88
Explanation of electricity prices						
Regression model 1: $Price_{el} = \alpha + \beta * RES + \gamma * Load_{el} + \delta * Residualload_{H_2} + \epsilon$						
intercept (α)	Ref	0.25	23.83	18.13	-52.00	7.35
	HI	-24.15 *	-1.11	3.31	-95.16 *	-34.18
	LD	-2.69	22.33	16.30	-54.41	4.36
	HI/LD	-17.66 *	6.18	7.48	-81.19 *	-32.26
renewable generation coefficient (β)	Ref	-21.12 **	-14.95 **	-22.11 **	-25.96 **	-26.93 **
	HI	-21.21 **	-14.64 **	-23.05 **	-26.72 **	-26.22 **
	LD	-21.36 **	-15.64 **	-22.51 **	-26.08 **	-26.90 **
	HI/LD	-21.85 **	-17.84 **	-23.31 **	-26.17 **	-25.93 **
electrical load coefficient (γ)	Ref	31.23 **	15.34 **	31.96 **	38.78 **	35.79 **
	HI	29.86 **	13.99 **	33.70 **	37.68 **	32.79 **
	LD	31.92 **	16.49 **	33.33 **	39.13 **	36.13 **
	HI/LD	32.55 **	20.70 **	35.35 **	37.61 **	34.29 **
hydrogen residual load coefficient (δ)	Ref	0.04 **	0.04 *	0.02	0.09 *	0.04 *
	HI	0.05 **	0.05 *	0.03	0.10 *	0.06 *
	LD	0.04 **	0.04 *	0.02	0.09 *	0.04 *
	HI/LD	0.05 **	0.04 *	0.02	0.10 **	0.06 *
R^2	Ref	0.85	0.65	0.57	0.71	0.78
	HI	0.84	0.62	0.55	0.70	0.76
	LD	0.85	0.67	0.58	0.70	0.77
	HI/LD	0.85	0.67	0.59	0.69	0.73
Explanation of hydrogen prices						
Regression model 2: $Price_{H_2} = \alpha + \beta * RES + \gamma * Load_{el} + \delta * Residualload_{H_2} + \epsilon$						
intercept (α)	Ref	69.86 **	99.89 **	74.79 **	70.94 *	84.85 *
	HI	47.35 **	103.33 **	77.56 **	73.61 *	-31.75
	LD	68.81 **	100.54 **	72.07 **	69.83 *	79.53 *
	HI/LD	44.84 **	101.92 **	74.41 **	62.45 *	-26.16
renewable generation coefficient (β)	Ref	-13.29 **	-0.05	-5.59 **	-16.11 **	-46.55 **
	HI	-10.54 **	-0.34 **	-6.34 **	-10.13 **	-34.54 **
	LD	-14.01 **	-0.06	-6.22 **	-18.29 **	-47.10 **
	HI/LD	-11.90 **	-0.41 **	-7.03 **	-12.24 **	-37.54 **
electrical load coefficient (γ)	Ref	25.54 **	0.13	6.81 **	26.30 **	71.05 **
	HI	20.02 **	1.23 **	9.97 **	19.02 **	46.06 **
	LD	27.02 **	0.15	9.65 **	29.99 **	71.36 **
	HI/LD	23.17 **	1.45 **	11.87 **	22.04 **	52.32 **
hydrogen residual load coefficient (δ)	Ref	0.00	0.00	0.02 *	0.01	-0.01
	HI	0.02 *	0.00	0.01	0.01	0.09 *
	LD	0.00	0.00	0.02	0.01	0.00
	HI/LD	0.02 *	0.00	0.01	0.02	0.10 *
R^2	Ref	0.49	0.05	0.32	0.46	0.75
	HI	0.48	0.30	0.28	0.38	0.59
	LD	0.50	0.05	0.32	0.47	0.75
	HI/LD	0.50	0.34	0.29	0.43	0.60

Significance levels: ** p-value$<$0.01; * p-value$<$0.1.
The hydrogen residual load is calculated by subtracting the constant hydrogen import via ship from the exogenous demand profile in the transport, buildings, and industry sector. Electrical load equals the sum of the exogenous demand profiles in the end-use sectors.

Changes in cross-border hydrogen trade infrastructure notably affect the strength of price coupling and the explanatory power of key variables. In the *HI* and *HI/LD* scenarios, price coupling weakens in most

subsets compared to the reference case, as indicated by lower correlation coefficients under conditions of low or asymmetric residual load. This suggests that increased corss-border trade availability reduces the short-term responsiveness of hydrogen prices to electricity market dynamics in these situations. By contrast, in the subset with high residual load in both markets (*El. high RL / H_2 high RL*), price decoupling weakens significantly. The coefficient of correlation increases from 0.08 in the reference scenario to 0.20 (*HI*) and 0.25 (*HI/LD*), and the explanatory power of the regression model improves (R^2 increases from 0.05 to 0.30 and 0.34, respectively). This shift reflects a greater role of electrolysis in setting hydrogen prices, even during periods of elevated electricity prices, as storage discharge becomes less frequent. Nevertheless, correlation in this subset remains lower than in others, indicating persistent decoupling. Electricity price formation is largely unaffected by changes in cross-border hydrogen trade infrastructure, both over the full year and within subsets. In contrast, hydrogen price formation shows some increased sensitivity to hydrogen residual load for the full-year, though this effect remains insignificant in most subsets. In the *El. high RL / H_2 high RL* subset, explanatory power increases substantially, with renewable generation and electrical load becoming significant drivers, highlighting a partial transition to more market-aligned hydrogen price dynamics in situations with high residual load.
A reduction in hydrogen demand in the *LD* scenario has no substantial impact on price formation for either hydrogen or electricity. However, the correlation between the hydrogen and electricity prices increases slightly in most subsets, indicating that lower hydrogen demand marginally strengthens price coupling. The explanatory power of the regression models remains broadly consistent with the reference case.

Overall, the results indicate that structural changes in cross-border hydrogen trade infrastructure and demand can influence both the strength of price coupling and the explanatory power of key price drivers, while effects are structural consistent across scenarios. NTC expansion generally weakens coupling, but improves price dependencies in situations with high residual load in both the hydrogen and electricity market. Demand reduction has limited effects on price formation, but modestly enhances price alignment between markets. Across all scenarios, electricity prices continue to be shaped primarily by short-term electricity market fundamentals, while hydrogen prices remain influenced by more structural characteristics driven by the interplay between storage, electrolysis, and imports and exports.

4. Discussion

This study analyzes shadow prices for electricity and hydrogen, providing fundamental insights into price formation mechanisms. However, to address the findings' real-world implications, it is crucial to discuss how these shadow prices and identified characteristics might translate into actual market prices and how they could align with the future energy system. In this context, the limitations of the modeling approach are explored. Additionally, the discussion examines how hydrogen import prices, storage dynamics, and cross-border trade may influence market outcomes. Finally, an outlook on challenges and opportunities in developing a functional hydrogen market is given.

Price formation depends not only on fundamental market dynamics but also on underlying model assumptions and limitations.
A key characteristic of the modeling framework is the separation of the investment and dispatch stages, which must be considered when interpreting shadow prices. In Step I, long-term investment decisions—including hydrogen import volumes via LTCs — are optimized based on full cost recovery. These LTC prices reflect LCOH, which include both capital and operational expenditures, as well as infrastructure components such as import terminals, reconversion facilities, and shipping. In contrast, Step II simulates short-term dispatch under fixed capacities and imports, optimizing only variable costs. Shadow prices in Step II are consistent with those for electricity, but exclude sunk and capital costs. The prices for hydrogen imports from non-European countries do not shape the hydrogen price duration curve. As a result, the daily shadow prices derived in Step II often fall below the marginal prices for imported hydrogen in Step I. This points to an oversizing of imports. However, Step I is not intended to provide a complete cost-optimal system, but rather to construct feasible and policy-aligned system configurations. These configurations serve as the basis for the high-resolution dispatch analysis in Step II, which is central to this paper. No iterative feedback loop exists between the two stages. Nevertheless, the fundamental differences between investment and dispatch market outcomes have important implications for price interpretation. While investment decisions ensure full cost recovery for infrastructure such as electrolyzers, storage, and renewables, the dispatch model does not guarantee financial viability for individual assets. Relying solely on shadow prices for valuation may therefore underestimate the revenue requirements for these assets. To bridge this gap, additional price components — such as capacity payments, mark-ups, or risk premiums — may be necessary to ensure cost recovery and incentivize investment. Furthermore, risk premiums arising from market uncertainties could

widen the gap between modeled shadow prices and actual market prices. As such, the price levels derived in this study should be viewed as lower bounds.

Daily hydrogen price fluctuations in the model revolve around the mean value. Hydrogen storage shifts supply over time without altering overall market conditions. Expanding hydrogen storage capacity would directly reduce price volatility by mitigating both high and low residual load situations. During low residual load periods, increased storage charging would absorb excess hydrogen, leading to higher prices in those situations. Conversely, during periods with high residual load, larger storage reserves would provide additional supply, exerting downward pressure on prices. In an extreme case of unlimited storage capacity, daily hydrogen prices would correspond to one of two price levels. One price level would reflect storage discharging and the other would emerge in charging situations. The gap between the two price levels would reflect the storage efficiency. Weather variability and renewable electricity generation profiles also appear to play a crucial role in shaping price fluctuations. More stable electricity generation, achieved through a higher share of wind power relative to PV or by integrating battery storage, could further contribute to reduced hydrogen price volatility. In such cases, storage operation would likely exhibit fewer seasonal fluctuations, leading to more balanced storage usage throughout the year, as demonstrated in INES (2025).

The results indicate that the average hydrogen-to-electricity price ratio is approximately 0.56 on an annual basis, with substantial daily variations. This finding contrasts with previous studies, such as EWI (2021), Prognos et al. (2020), Fraunhofer ISI et al. (2021), and Böttger and Härtel (2022), who estimate the ratio to range between 0.7 and 1.2, with an average of 0.9. The discrepancy may be driven by a key methodological difference regarding the treatment of hydrogen imports, the consideration of hydrogen storage, and trade restrictions. In the dispatch decision of the presented model, import volumes are fixed ex ante and do not respond to market signals. As a result, system flexibility is provided solely by electrolysis and storage. By contrast, studies assuming flexible hydrogen imports allow the model to import at a fixed price whenever needed. This assumption enables imports to act as a buffer, stabilizing hydrogen prices and maintaining a tighter link between electricity and hydrogen prices. In the fixed import setting of this study, rising hydrogen prices during high residual load situations cannot be offset by additional imports. Consequently, the hydrogen price becomes less responsive to short-term electricity price fluctuations, reducing the average electricity-to-hydrogen price ratio. Nonetheless, hydrogen price levels might decrease if LTC contracts are better aligned with seasonal demand variations rather than maintaining constant import volumes throughout the year. Additionally, reducing the share of LTC-based imports while increasing the share of flexible imports, reflected by lower Take-or-pay rates, has been shown to lower overall system costs (Keutz and

Kopp, 2025), indicating lower hydrogen price levels and thus higher price ratios. Additionally, infrastructure availability influences price ratios. The clustering analysis indicates that the lowest electricity-to-hydrogen price ratios occur during periods when both hydrogen and electrical residual loads are low. In these situations, electrolysis predominantly sets prices. Indicated by overall price alignment of hydrogen prices across countries, cross-border trade appears to be generally unconstrained, whereas electricity prices in Germany experience stronger downward movements compared to neighboring countries. Consequently, although hydrogen prices generally correlate with electricity prices, higher electricity prices in countries next to Germany exert upward influence on hydrogen prices. Thus, compared to the former mentioned studies, more cross-border trade congestions may occur.

Beyond short-term price formation characteristics, the high price for hydrogen LTCs in the investment decision stage may present significant challenges for the long-term demand developments across various end-use sectors. The industrial sector, in particular, could face economic pressure that incentivizes shifting to cost-competitive alternative fuels or relocating to regions with lower energy costs, potentially altering regional hydrogen demand. Recent studies support this view: Weißenburger et al. (2024) show hydrogen demand has price elasticity and declines at high prices, but still remains substantial across sectors. Similarly, Fraunhofer ISI (2023) find that while transport and some industrial sectors reduce demand at high prices, a significant share remains inelastic due to limited alternatives or relocation challenges. EWI (2024) further notes heterogeneous willingness to pay across sectors — with transport and some industrial sectors characterized by a high willingness to pay. In this study, hydrogen demand is modeled as exogenous and price-inelastic, but literature suggests substantial demand persistence despite price pressures, supporting this assumption Nevertheless, to account for potential long-term demand reductions in response to sustained high price levels, the *LD* sensitivity provides insights into the possible implications of reduced hydrogen consumption.

Finally, the analysis shows that the hydrogen equilibrium constraint faces a limited degree of heterogeneity, with storage, electrolyzers, trade and power plant consumption representing the primary flexibilities. Limited heterogeneity in flexibility may pose a challenge for the development of a functional and liquid hydrogen market. Insufficient demand responsiveness can weaken price signals and hinder efficient market interactions. Without mechanisms to enhance flexibility, the establishment of a hydrogen market could remain difficult. Other studies, such as Schönfisch (2022), also pronounce that regional and heterogeneous hydrogen price structures could emerge across Europe, with trade capacities as one flexibility option playing a key role in linking these markets. Thus, the construction of sufficient cross-border hydrogen trade infrastructure next to storage appears important for enabling market maturity and ensuring that hydrogen price disparities between European countries do not result in economic imbalances, where some regions face prohibitively high costs while others benefit from significantly lower hydrogen prices.

5. Conclusion

In climate-neutral energy systems, hydrogen is expected to play a pivotal role across diverse applications with distinct demand and supply patterns. However, significant uncertainty remains regarding its price level, volatility and interdependencies with electricity prices. While optimal system configurations of an integrated energy system were in scope of previous studies, the granular interplay between hydrogen and electricity prices under varying short-term market conditions has been insufficiently explored. This study fills this gap by investigating the fundamental price formation of hydrogen and the relationship between hydrogen and electricity prices across different system configurations with a focus on Germany and for a climate-neutral Europe. This was achieved by expanding the energy system model DIMENSON towards a more granular representation of PtX fuels with different supply and demand options within the equilibrium constraint. The resulting shadow prices were analyzed using co-integration tests, regression and correlation metrics, price ratio distributions, and statistical properties.

5.1. Main results

The analysis suggests that the fundamental relationship between hydrogen and electricity prices in a future, climate-neutral energy system is likely to be predominantly influenced by short-term market conditions. Electricity prices appear to respond closely to renewable generation and demand fluctuations, as shown by significant regression results. By contrast, hydrogen prices are less responsive to these factors and seem to be more structurally influenced. Factors such as storage behavior and cross-border trade can moderate hydrogen price formation. The results point to strong price coupling under low residual load conditions dominated by electrolysis-driven pricing, promoting a general linkage with the electricity market. In situations with high residual load, more pronounced decoupling may occur, with hydrogen price formation driven by storage discharge and supply limitations, highlighting the potential impact of constrained system flexibility. The electricity-to-hydrogen price ratio averages approximately 0.56, lower than previously reported values, largely due to assumptions on inflexible hydrogen imports.

Scenario analyses indicate that variations in cross-border hydrogen trade infrastructure and demand modestly influence price formation and price coupling strength: The expansion of NTCs fo hydrogen slightly weakens price coupling independent on the underlying market situation driven by residual load, but with an exception for high residual load situations, where previously identified decoupling weakens. Reduced hydrogen demand has minimal impact. Despite these variations, the fundamental price relationship remains stable yet sensitive to short-term system dynamics.

While these findings offer insights based on shadow prices, real-world market prices are likely to diverge. Shadow prices do not ensure investment cost recovery, and do not include risk premia, or capacity mark-ups. In particular, hydrogen imports are priced based on full cost recovery via long-term contracts, leading to a structural price gap between imported and domestically produced hydrogen. As a result, short-term price signals alone may be insufficient to support investment in hydrogen storage and electrolysis, underscoring the importance of complementary mechanisms such as long-term contracts or regulatory support to ensure the development of a liquid market for hydrogen.

5.2. Future research

Based on the findings, this work reveals several areas for further investigation. Further analysis could assess how the development of regional and international hydrogen trade networks affects price formation. This includes evaluating the interplay between domestic production, imports, and exports for other regions next to Germany. Although this study highlights short-term price dynamics, future research could also explore the long-term development of coupling between hydrogen and electricity markets by considering multiple years. Thus, changes in price dynamics within a longer period of time can be analyzed. Future research could also further investigate the competitiveness of specific assets and prove robustness across different market situations. Especially the comparison of the profitability of hydrogen storage next to electricity storage could be interesting. Furthermore, the provided understanding of market situations within this study could lay the basis to further investigate different design options for contracts for difference or hydrogen purchase agreements, similar to power purchase agreements. Last, future modeling efforts should address short- and long-term supply and demand elasticities to capture their influence on market dynamics. Other model improvements could also consider more diverse weather situations or more flexible hydrogen supply profiles via ship.

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Nomenclature

Abbreviations

Table 7: Table of abbreviations

ADF	Augmented Dickey-Fuller test	HI/LD	System sensitivity with high infrastructure and low demand
CCGT	Combined cycle gas turbine	LCOH	Levelied costs of hydrogen
CHP	Combined heat and power	LD	system sensitivity with low demand
CV	Coefficient of variation	LTC	Long-term contracts
DSM	Demand side management	NTC	Net Transfer Capacities
el./EL	Electricity	OCGT	Open cycle gas turbine
EU	European Union	PHS	Pumped hydro storage
H_2	Hydrogen	PtX	Power to X
HI	System sensitivity with high infrastructure	TYNDP	Ten year network development plan

Sets, parameters and decision variables

Table 8: Sets

Set	**Unit**	**Description**
$a \in A$	-	All technologies
$a \in A^{H_2 Stor}$	-	Hydrogen storage
$b, b_1 \in B$	-	Country
$d \in D$	-	Day
$f \in F$	-	Fuel
$h \in H$	-	Hour
$r \in R$	-	Hydrogen exporting region outside Europe
$s \in S$	-	Sector

Table 9: Decision variables

Variable	**Unit**	**Description**
$COSTS^{Pipe}$	EUR	Annual costs for fuel imports via pipeline from outside the EU.
$COSTS^{Ship}$	EUR	Annual costs for fuel imports via shipping from outside the EU.
$USE(b, d, s, f)$	MWh_{th}	Fuel f consumption in sector s of country b on day d.
$INSTOR(d, b, a, f)$	MWh_{th}	Fuel f stored in facility a in country b on day d.
$INSTOR^{Pipe}(d, b, f)$	MWh_{th}	Pipeline-imported fuel f stored in country b on day d.
$INSTOR^{Prod}(d, h, a, b, f)$	MWh_{th}	Domestically produced fuel f via technology a stored in country b on day d and hour h.
$INSTOR^{Ship}(d, r, b, f)$	MWh_{th}	Ship-imported fuel f from region r stored in country b on day d.
$INSTOR^{Trade}(d, b_1, b, f)$	MWh_{th}	Imported fuel f from neighboring country b_1 stored in country b on day d.
$LEVEL(d, a, b, f)$	MWh_{th}	Storage level of fuel f using technology a in country b on day d.
$PIPE(b, f)$	MWh_{th}	Pipeline imports of fuel f into country b.
$SHIP(r, b, f)$	MWh_{th}	Ship imports of fuel f from region r to country b.
$TRADE(d, b_1, b, f)$	MWh_{th}	Export of fuel f from country b_1 to country b on day d.
$TRADE(d, b, b_1, f)$	MWh_{th}	Export of fuel f from country b to country b_1 on day d.
$PROD(d, h, a, b, f)$	MWh_{th}	Domestic production of fuel f in country b on day d, hour h, using technology a.

Table 10: Parameters

Parameter	**Unit**	**Description**
$\eta(a)$	-	Round-trip efficiency of storage technology a.
$instcap(a, b)$	MW	Installed capacity of technology a in country b.
$inject(a)$	-	Quotient of injection speed to withdrawal speed for storage technology a.
$ptxPotPipe(b, f)$	MWh_{th}	Import potential of fuel f via pipeline to country b.
$ptxPotShip(r, f)$	MWh_{th}	Import potential of fuel f from exporting region r.
$ptxTerminal(b, f)$	MWh_{th}	Terminal capacity for handling fuel f in country b.
$ptxCostsPipe(b, f)$	EUR/MWh$_{th}$	Variable cost of importing fuel f via pipeline to country b.
$ptxCostsShip(r, f)$	EUR/MWh$_{th}$	Variable cost of importing fuel f via ship from region r.
$tradeCap(b_1, b, f)$	MWh_{th}/day	Net transfer capacity (NTC) for trade of fuel f between countries b_1 and b.
$vol(a)$	h	Volume factor (storage capacity per unit of installed power) for storage technology a.

Appendices

A. H_2 supply curve

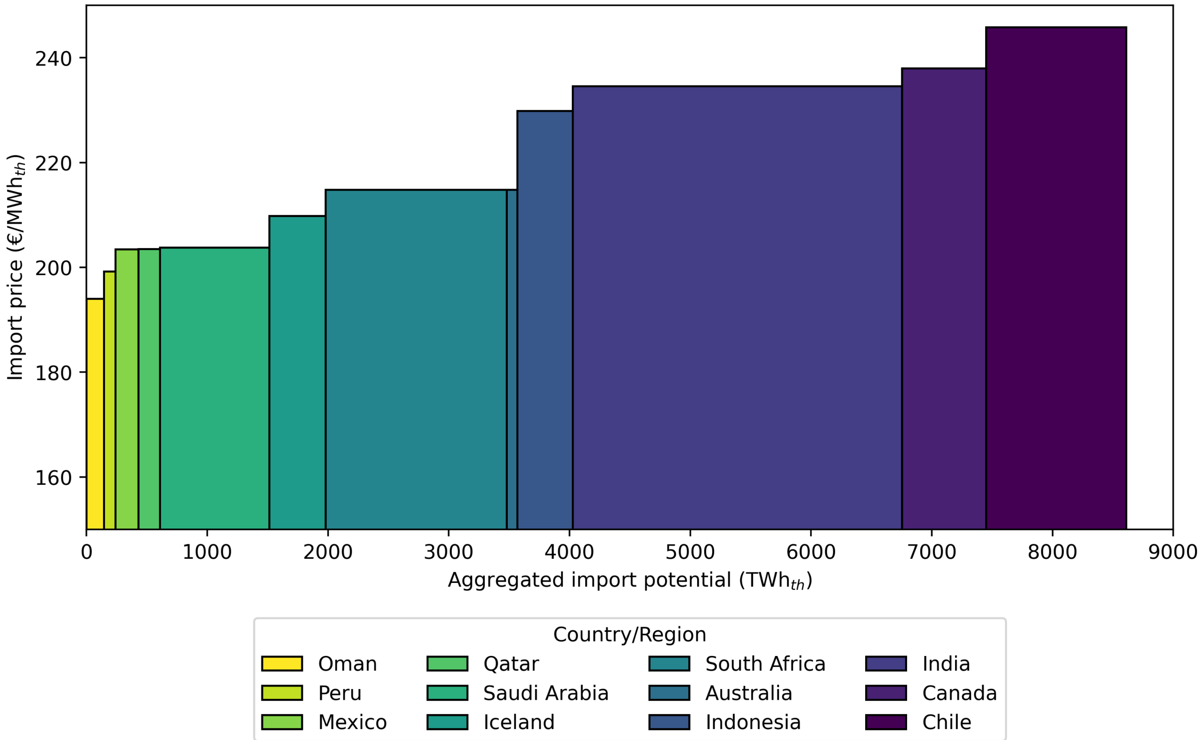

Figure A.1: Supply curve for H_2 imports via ship

The hydrogen import price reflects the price for a long-term contract with baseload supply throughout the year. The price also reflects the levelized costs of hydrogen (LCOH) of the exporting region, covering both operational and capital expenditures.

B. ***Trade capacities***

Table B.1: Trade capacities for hydrogen and electricity

Countries		Hydrogen [MW_{th}] Scenarios *Ref* and *LD*		Hydrogen [MW_{th}] Scenarios *HI* and *HI/LD*		Electricity [MW_{el}] All scenarios	
a	**b**	**from a to b**	**from b to a**	**from a to b**	**from b to a**	**from a to b**	**from b to a**
AT	**CH**	0	0	0	0	1,200	1,200
AT	**CZ**	0	0	0	0	900	900
AT	**DE**	6,250	6,250	6,250	6,250	7,500	7,500
AT	**HU**	6,250	0	6,250	0	800	800
AT	**IT**	5,250	7,000	9,125	7,000	1,375	1,995
AT	**SI**	0	0	1,375	667	1,450	1,450
BE	**DE**	3,790	3,790	4,998	4,998	1,000	1,000
BE	**FR**	4,500	4,500	8,333	8,333	5,800	7,300
BE	**GB**	0	0	8,333	8,333	2,400*	2,400*
BE	**LU**	580	580	1,413	1,413	1,100	1,000
BE	**NL**	2,000	2,000	10,000	10,000	4,400	4,400
BE	**NO**	0	8,333	8,333	8,333	0	0
BG	**GR**	3,330	3,150	3,665	3,671	2,200	1,900
BG	**RO**	740	740	5,811	5,811	2,550*	2,550*
CH	**DE**	0	0	10,000	10,000	4,500*	5,000
CH	**FR**	0	0	4,167	4,167	3,200	5,500
CH	**IT**	5,630	3,670	5,630	3,670	5,800*	3,110*
CZ	**DE**	6,000	6,000	13,300	13,300	3,000*	3,000*
CZ	**PL**	0	0	1,250	1,250	1,600	1,000
CZ	**SK**	0	6,000	6,500	6,500	2,300	2,160*
DE	**DK1**	2,100	2,100	10,000	10,000	3,500	3,500
DE	**DK2**	0	0	0	0	600	600
DE	**FR**	8,000	8,500	10,125	10,125	4,800	4,800
DE	**GB**	0	0	0	0	2,800	2,800
DE	**LU**	0	0	0	0	3,700*	3,700*
DE	**NL**	500	15,630	23,300	23,296	6,000	6,000
DE	**NO**	17,250	17,250	17,250	17,250	1,444*	1,444*
DE	**PL**	4,170	8,330	9,467	9,461	3,000*	3,000
DE	**SE**	0	0	0	0	1,500*	1,491
DK1	**DK2**	0	0	0	0	600	600
DK1	**GB**	0	0	0	0	1,400	1,400
DK1	**NL**	0	0	0	0	700	700
DK1	**NO**	0	0	0	0	1,632	1,632
DK1	**SE**	0	0	0	0	1,415	1,415
DK2	**PL**	0	0	0	0	500	500*
DK2	**SE**	0	0	0	0	2,200	1,800
EE	**FI**	4,170	8,330	8,337	8,330	1,176	1,176
EE	**LV**	8,330	4,170	8,330	5,285	1,444*	1,259*
ES	**FR**	9,000	9,000	9,000	9,000	8,000	8,000
ES	**PT**	3,380	3,380	3,380	3,380	6,200	5,500
FI	**NO**	0	0	0	0	150*	150*
FI	**SE**	27,750	27,750	37,917	37,917	4,500	4,500
FR	**GB**	0	0	0	0	6,800*	6,800*
FR	**IE**	0	0	0	0	700	700
FR	**IT**	0	0	0	0	4,485	2,160
FR	**LU**	0	0	0	0	380*	0
GB	**IE**	0	0	1,189	1,189	1,750	1,750
GB	**NL**	0	0	0	0	2,800*	2,800*
GB	**NO**	0	0	0	0	1,444*	1,444*
GR	**IT**	0	0	0	0	1,500*	1,500*
HR	**HU**	0	0	5,350	5,350	1,700*	1,700*
HR	**SI**	0	0	667	1,375	3,200	3,200
HU	**RO**	3,200	3,200	6,400	6,400	3,027	2,300*
HU	**SI**	0	0	817	817	1,700	1,700
HU	**SK**	4,170	4,170	8,337	8,337	1,900*	3,360*
IT	**SI**	0	0	817	817	1,080	1,153
LT	**LV**	4,170	8,330	7,903	8,330	1,300*	1,300*
LT	**PL**	8,330	4,170	8,330	7,150	700	700
LT	**SE**	0	0	0	0	1,300	1,300
NL	**NO**	0	0	0	0	723*	723*
NO	**SE**	0	0	0	0	3,695	3,995
PL	**SE**	0	0	0	0	600	600
PL	**SK**	0	0	0	0	894*	1,110

Hydrogen capacities in Scenario A are based on the reference grid from ENTSO-E and ENTSOG (2024). Scenario B assumes full utilization of all investment candidates. Electricity NTC values are derived from the ENTSO-E and ENTSOG (2024) "Global Ambition" scenario for the weather year 2009. Adjustments marked with * indicate that if the value was smaller than the corresponding value from the ERAA 2024 (ENTSO-E, 2024) for 2035, the higher value was used.

C. ***Installed capacities***

Table C.1: Installed electrical capacities in Germany per generation group in GW_{el} and corresponding efficiencies for the different system configuration scenarios

Technology group	**Efficiency**	**Ref**	**HI**	**LD**	**HI/LD**
Gas	-	-	-	-	-
- Gas OCGT	28-40	Inf	Inf	Inf	Inf
- Gas CCGT	40-60	16.5	15.9	14.6	11.4
- Gas CHP	42-56	2.7	2.9	2.7	2.9
- H_2 OCGT	40	Inf	Inf	Inf	Inf
- H_2 CCGT	60	12.7	15.0	13.5	10.8
- H_2 CHP	56	10.7	10.7	10.7	10.7
Wind Offshore	100	70.0	70.0	70.0	70.0
Wind Onshore	100	160.0	160.0	160.0	160.0
Photovoltaic	100	400.0	400.0	400.0	400.0
Biomass	-	-	-	-	-
- Biomass no CHP	39	0.0	0.0	0.0	0.0
- Biomass CHP	31-49	8.0	8.0	8.0	8.0
Hydropower	100	5.3	5.3	5.3	5.3
DSM (Industry)	100	5.4	5.4	5.4	5.4
Battery	90	36.0	36.0	36.0	36.0
PHS	76	8.5	8.5	8.5	8.5
Electrolysis	72-77	76.5	74.4	76.5	76.5

Targets for Wind Onshore, Wind Offshore, and PV capacities align with the objectives defined in the Easter Package (Bundesrat, 2022). For battery storage, a ratio between power and capacity of 1:2 is assumed based on ENTSO-E and ENTSOG (2024). OCGT power plants for H_2 and Gas have sufficient capacities to keep the model feasible.

Table C.2: Installed hydrogen storage capacities in Germany in TWh_{th} and corresponding efficiencies for the different system configuration scenarios

Technology group	**Efficiency**	**Ref**	**HI**	**LD**	**HI/LD**
Cavern conversion	93	29.7	29.7	29.7	24.8
Cavern new	93	11.6	5.9	27.0	6.6
Pore conversion	93	0.0	0.0	0.0	0.0
Pore new	93	0.0	0.0	0.0	0.0

For hydrogen, the country-specific storage capacities align with the local potentials derived from Caglayan et al. (2021).

D. ***Electricity and hydrogen demand***

Table D.1: Electricity and hydrogen demand in TWh for different sectors and system configuration scenarios

		Ref		**HI**		**LD**		**HI/LD**	
Sector	**Subsector**	$\mathbf{H_2}$	**El.**	$\mathbf{H_2}$	**El.**	$\mathbf{H_2}$	**El.**	$\mathbf{H_2}$	**El.**
Energy	Electricity*	67.8	43.3	67.8	42.7	67.8	43.7	67.9	43.3
	PtX*	38.7	331.0	33.3	331.1	54.7	330.0	32.6	331.5
	District heating*	0.0	26.1	0.0	26.1	0.0	26.1	0.0	26.1
	Others	0.0	31.1	0.0	31.1	0.0	31.1	0.0	31.1
Transport	Road transport	90.0	104.2	90.0	104.2	90.0	104.2	90.0	104.2
	Non-road transport (dom.)	4.4	17.0	4.4	17.0	4.4	17.0	4.4	17.0
	Non-road transport (inter.)	4.4	0.0	4.4	0.0	4.4	0.0	4.4	0.0
Buildings	Heating, cooling, cooking	78.6	109.9	78.6	109.9	78.6	109.9	78.6	109.9
	Lightning, el. appliances	0.0	176.7	0.0	176.7	0.0	176.7	0.0	176.7
Industry	Processes	279.2	256.0	279.2	256.0	195.4	256.0	195.4	256.0
	Non-energy	127.6	0.0	127.6	0.0	127.6	0.0	127.6	0.0
Agriculture	-	18.9	5.5	18.9	5.5	18.9	5.5	18.9	5.5
Total	-	710	1133	704	1133	641	1133	620	1134

Note that endogenously determined demand is labeled with *.

E. ***Hydrogen balances***

Table E.1: H_2 origin and export balance in TWh_{th}

		Ref	**HI**	**LD**	**HI/LD**
Supply	Domestic production and storage supply	281.9	274.6	296.0	276.6
	Import from EU	408.0	781.9	426.1	814.8
	Import via ship*	241.3	87.6	151.3	69.7
Demand	Export to EU	221.6	439.9	231.5	541.2
	Storage loading	38.7	33.3	54.7	32.6
	Sectoral demand	670.9	670.9	587.2	587.3

* The import via ship is determined with the invest decision and fixed in the dispatch run.

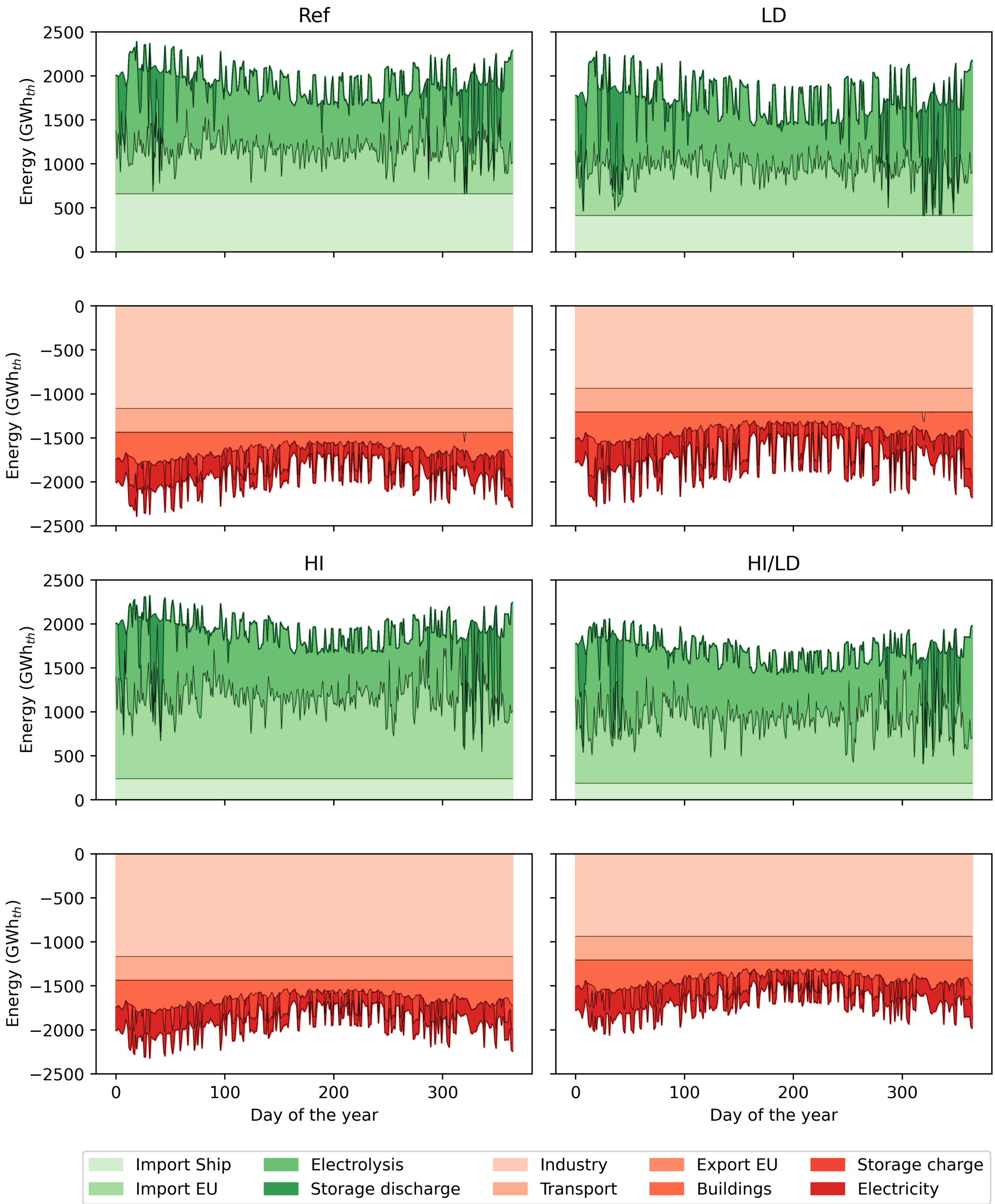

Figure E.1: Daily H_2 balance for the different system sensitivities

F. *Storage level*

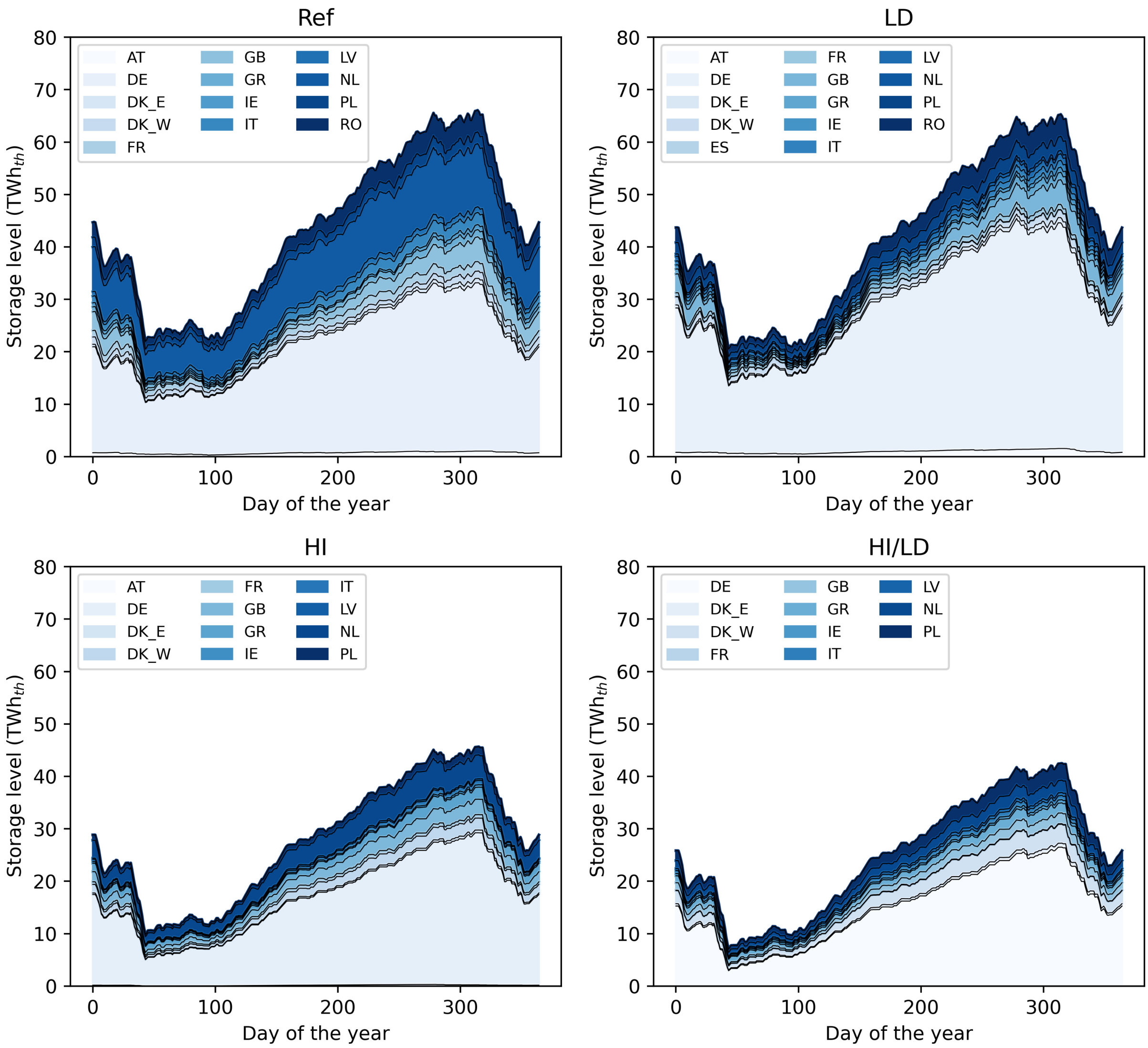

Figure F.1: H_2 storage level in Europe in each sensitivity

G. H_2 balance and residual load in each subset for the reference scenario

The full dataset includes price data for hydrogen and electricity, along with the corresponding demand and supply values across different technologies, sectors, and assets. It is divided into four subsets, each capturing distinct market conditions characterized by variations in electrical and hydrogen residual load. These subsets are visualized in Figure G.1.

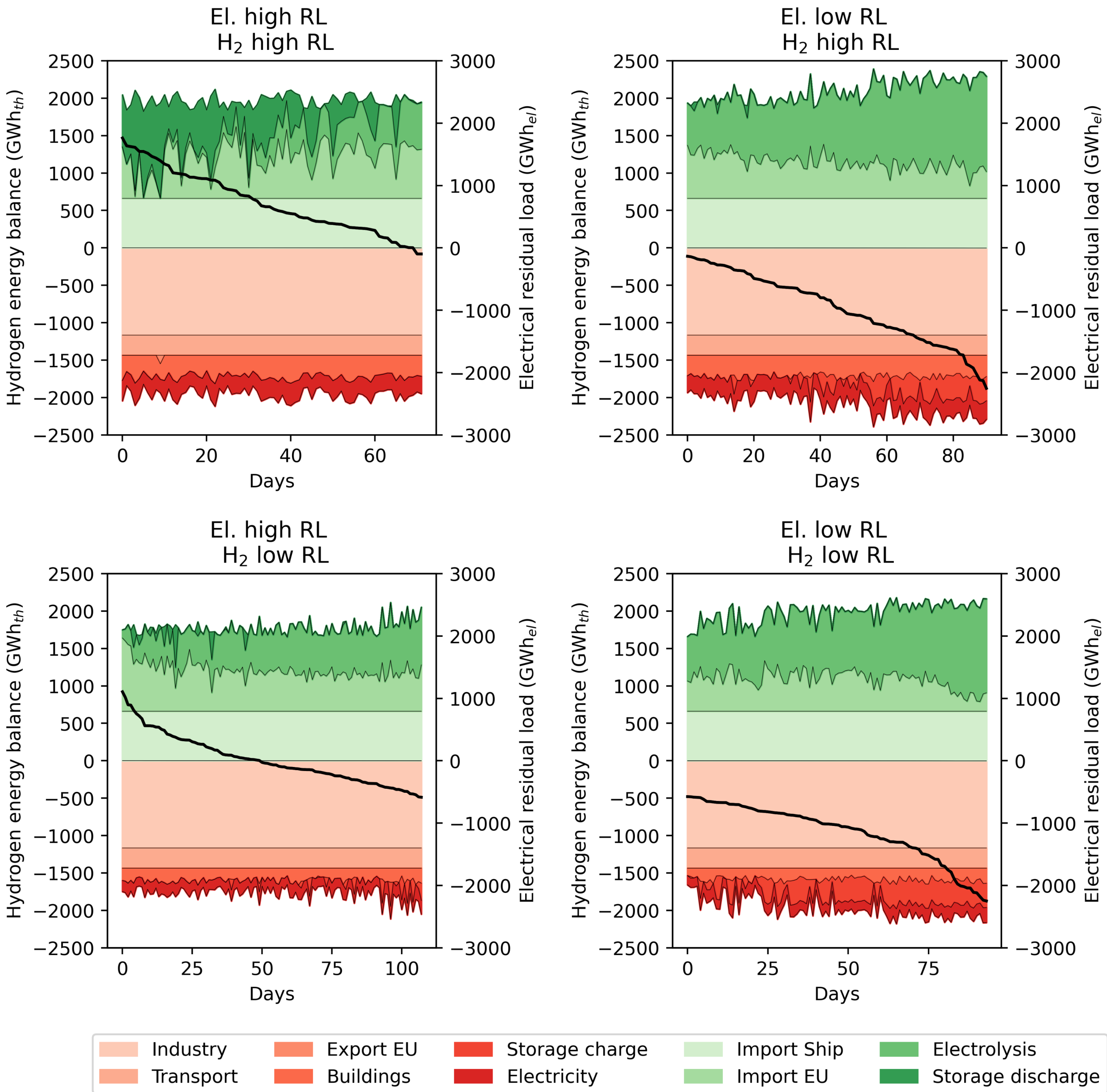

Figure G.1: Daily H_2 balance in each subset with the corresponding residual load in sorted order

The electrical residual load is represented on the secondary y-axis and is displayed in descending order. The H_2 supply and demand mix is visualized for the corresponding days, aligned with the sorted order of the residual load values.

H. Check for co-integration

The separation of price data according to different market situations raises the question of whether hydrogen and electricity prices may be co-integrated within individual subsets. For co-integration analysis to be applicable, it is first necessary to confirm that the price series are non-stationary. The stationarity of electricity and hydrogen price time series was assessed using the ADF test. Table H.1 presents the results, which demonstrate that none of the subsets exhibit non-stationarity in both series. This conclusion is supported by p-values well below the 0.05 significance threshold, indicating that the series are stationary. A stationary time series is characterized by statistical properties, such as mean and variance, that remain constant over time, implying the absence of long-term trends or unit roots. In technical terms, stationary series are integrated of order zero (I(0)). Co-integration analysis is typically used for non-stationary time series (I(1)) that share a linear relationship, resulting in residuals that are stationary. Since all series in each subset are stationary, co-integration analysis cannot be applied. The stationary nature of these time series implies that their dynamics can be effectively analyzed using conventional statistical methods, such as regression analysis and correlation metrics, without accounting for long-term equilibrium relationships. Furthermore, the absence of non-stationarity suggests that the relationship between hydrogen and electricity prices is predominantly shaped by short-term interactions rather than shared long-term trends. This provides a foundation for focusing on dynamic interactions within specific market conditions, enabling a more nuanced understanding of their dependencies.

Table H.1: Results of the ADF-test for stationarity

Scenario		**El. high RL H_2 high RL**		**El. high RL H_2 low RL**		**El. low RL H_2 high RL**		**El. low RL H_2 low RL**	
		H_2	EL	H_2	EL	H_2	EL	H_2	EL
Ref	ADF statistic	-6.819	-6.846	-7.996	-6.315	-6.300	-8.298	-9.267	-9.230
	p-value	0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000
	stationary	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
HI	ADF statistic	-4.907	-6.908	-8.453	-5.260	-7.816	-8.460	-7.841	-8.996
	p-value	0.000	0.004	0.000	0.000	0.001	0.000	0.000	0.000
	stationary	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
LD	ADF statistic	-6.819	-6.892	-8.355	-6.234	-8.016	-8.293	-9.181	-5.237
	p-value	0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000
	stationary	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
HI/LD	ADF statistic	-6.819	-6.892	-8.355	-6.234	-8.016	-8.293	-9.181	-5.237
	p-value	0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000
	stationary	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

The significance level for stationarity is p-value>0.05.

I. ***Hydrogen and electricity price duration curves***

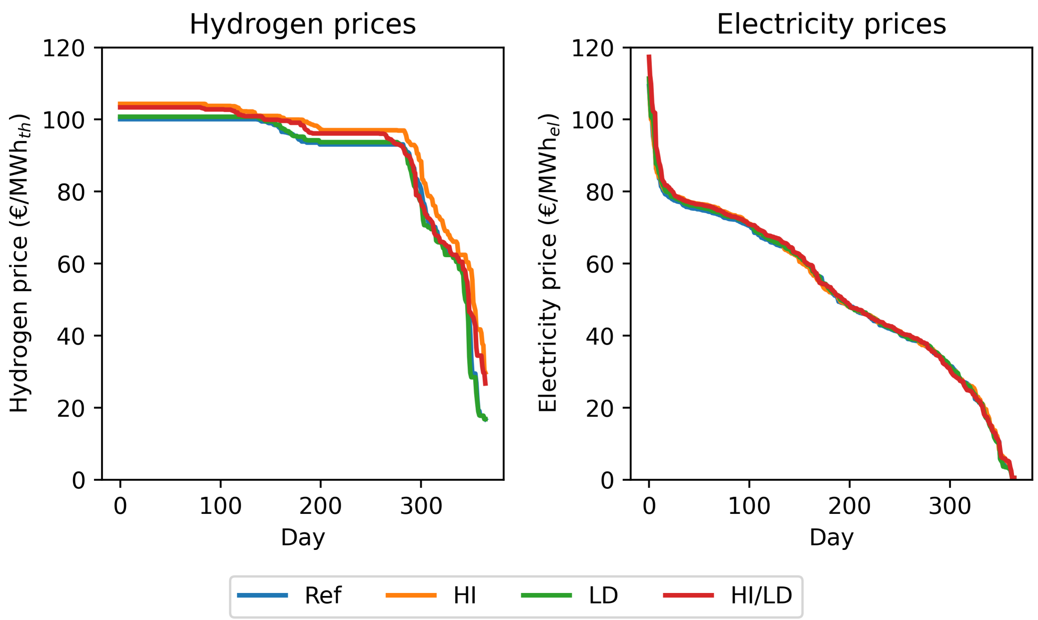

Figure I.1: Price duration curves for hydrogen and electricity

The price data are shown for Germany. Hourly electricity prices are weighted by the corresponding demand to calculate daily prices. Both electricity and hydrogen prices represent the shadow prices of their respective equilibrium constraints.