Industrial Heat Flexibility in Europe: Country-Level Feasibility of Electric Latent Heat Storage under End-User Electricity Price

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Abstract:

Electric latent heat storage can decouple industrial steam generation from electricity price peaks, but its business case is highly country specific. National regulations on end-use electricity price components such as grid fees, taxes, levies and exemptions vary and influence the feasibility of the storage implementation. Three contrasting European power systems - Germany, Spain and Poland - are compared and ranked by economic and ecologic attractiveness of electric heat storage integration for industrial steam production. Using 2024 Day-Ahead prices (EPEX, OMIE, TGE) a cost function is set up including further country specific price components. These inputs feed a MILP optimization model built in Python using the Open Energy Modelling Framework oemof.solph of a case study energy system. The case study consists of a gas boiler and an electric heat storage based on a latent heat storage currently developed by Fraunhofer-Institute UMSICHT. The electrical and thermal energy demand is modelled through a representative steam and electricity profile of a paper manufacturing company. The results clearly indicate that electric thermal energy storage is not a technology-constant but a market- and policy-dependent outcome. The sensitivity analysis results isolate the dominant drivers per country, such as price dispersion, grid fees treatment and emission levels. This decision-oriented ranking assists technology developers and policymakers target markets, sizes, and cost reforms to unlock industrial heat flexibility.

Keywords:

Day-ahead market; Electricity price regulations; Industrial energy system flexibility; Process steam electrification; Thermal energy storage.

1. Introduction

1.1. Industrial Context and Country-Specific Challenge

The industrial manufacturing sector accounts for around one quarter of Europe's energy demand [1]. The dominating part of this energy demand can be assigned to process heat, which is heat required for manufacturing processes like drying, melting and boiling. For heat required in low- to medium- temperature ranges steam is widely used as heat transfer medium. This is often used in the manufacture of chemicals, food and beverages, pulp and paper products and rubber and plastics. This high, and often inflexible steam demand is primarily supplied by fossil-fired steam generators, such as natural gas boilers. For the defossilisation of process steam, different electrification options are considered, such as electrode boilers and heat pumps.

As for the electric supply, European power systems are undergoing a rapid transition towards high shares of variable renewable generation. This increases the temporal mismatch between electricity supply and industrial heat demand and amplifies the value of flexibility on both the electricity and heat side. Enabling industrial steam systems to respond to temporal variations in electricity prices is therefore a key lever for cost-effective defossilization and system integration. Electrically charged latent heat storages offer a solution for this mismatch. They could charge and store heat at low electricity prices and discharge heat in form of steam when it is required or electricity is more expensive.

1.2. Research Gap, Objectives and Contributions

However, the widely analysed economic potential of operating storage technologies against wholesale spot prices often neglects a crucial reality: industrial end-users face a composite end-user electricity price that includes not only the energy wholesale price but also grid fees, taxes, levies and other surcharges, many of which are largely independent of short-term spot prices.

The composition and design of these end-user price components are highly country specific. Germany, Spain and Poland provide three European contrasting examples. In Germany, next to the energy component of electricity prices, the peak-load dependent network charges strongly contribute to the end-user price, as well as a complex regime of reductions and exemptions for large consumers [2]. These elements can substantially erode arbitrage margins or even make additional electrification more expensive than continuing to use fossil fuels for steam generation [2]. Spain features pronounced time-of-use (TOU) structures and a power system with high solar penetration, leading to characteristic midday price troughs [3, 4]. Poland, still heavily reliant on coal, combines relatively high marginal emissions of electricity with its own set of capacity-related charges [4, 5]. As a result, the economic and environmental feasibility of integrating electric latent heat storage into an industrial system can differ substantially between these countries, even when the underlying technology and industrial process are identical.

This paper addresses this gap by assessing the country-level feasibility of integrating electric latent heat storage into an industrial energy system under realistic end-user prices in three countries: Germany, Spain and Poland. It analyses how country-specific industrial end-user electricity price components, such as energy, grid fees, taxes, levies, charges and exemptions, affect the economic attractiveness of electric thermal energy storage for process steam generation. A sensitivity analysis in this study helps determine the drivers that dominate feasibility in each country. And lastly, it contrasts and compares the economic and ecological outcomes across countries and formulates implications that this study has on technology developers and policy makers seeking to unlock industrial heat flexibility.

A mixed-integer linear programming (MILP) model is built in Python using the open-source energy modelling framework (oemof.solph) of an industrial energy system consisting of a natural gas boiler and an electric latent heat storage, supplied by the grid and serving a representative steam and electricity demand profile of a (synthetic) paper manufacturing company. The model is solved for a full year with 2024 Day-Ahead prices from EPEX SPOT (Germany), OMIE (Spain) and TGE (Poland). For each country, a detailed end-user electricity cost function is constructed that includes energy, grid fees, taxes, charges, levies and relevant exemptions for industrial consumers. Time-varying grid CO_2 (equivalent) intensities are derived from ENTSO-E generation data and used to evaluate the environmental impact of different operating strategies.

This paper is structured as follows. Section 2 provides background on electric latent heat storage and industrial electricity cost structures in the three analysed countries and positions this work within the existing literature. Section 3 describes the case study, data and optimisation model, including the construction of country-specific end-user electricity prices and grid CO_2 intensities. Section 4 presents the results for Germany, Spain and Poland, including cost and emission impacts, cross-country rankings and sensitivity analyses, discusses the implications for industry and policy and outlines limitations and future research needs. The paper is then concluded in section 6.

2. Background and Literature

2.1. Industrial Heat Flexibility and Power-to-Heat Options

Industrial process heat attributes to a substantial share of final energy consumption in Europe, with a large fraction supplied as saturated or superheated steam in sectors such as paper, chemicals, food and beverages, and pharmaceuticals. Steam systems are typically designed to provide continuous heat at fixed pressure and temperature levels. This rigidity has historically been matched by dispatchable fossil-fired boilers, above all natural gas boilers.

A range of technological options exist to provide industrial defossilised heat flexibility. On the load-side management side, measures such as process optimisation, production scheduling and demand response can shape the timing of heat demand. On the supply side, electrification including electric boilers, high-temperature heat pumps and direct resistance heaters allow fuel switching from gas to electricity. Thermal energy storage (TES) adds an additional degree of freedom by decoupling the timing of heat generation from the timing of heat use. Sensible TES based on hot water or molten salts is commercially established, while latent TES exploiting phase change materials can achieve higher energy density and discharge close-to-constant temperature levels. Electric latent heat storage combines the power-to-heat element with latent TES and a steam generation interface (through a simultaneous charging and discharging option), enabling electricity to be stored as heat when prices or emissions are low and discharged later as process steam.

2.2. Industrial Electricity Tariffs and Country Context

While industrial electrification and electric TES are often discussed in terms of wholesale or Day-Ahead electricity prices, industrial consumers are not met with solely these prices. Instead, they pay a composite end-user electricity price that typically comprises four main elements: energy procurement costs linked to wholesale markets or supply contracts, grid fees for transmission and distribution, state-imposed taxes, and various levies or surcharges to finance, for example, renewables support schemes or capacity mechanisms.

Grid fees, or network charges, typically include at least two of the following components: fixed charges (€/point of delivery), capacity-based charges (€/kW), and volumetric charges (€/kWh). Volumetric charges calculate a uniform price per kWh for all consumption supporting overall energy efficiency, however, they do not incentivize peak demand shifting. Capacity-based charges charge consumers based on their peak power demand over a defined period, encouraging peak reductions, yet they can disproportionately affect users with low energy use but high capacity needs. Time-of-use charges apply different energy prices at different times of the day, week, or year and can be static or dynamic to help shift demand to periods of high renewable generation and improve grid efficiency. Nonetheless, they rely on widespread smart metering and data infrastructure [6]. Germany, Spain and Poland exemplify three distinct industrial tariff and power system contexts.

In 2024 Germany's grid electricity mix contained more than half of renewable energy sources [4]. Meanwhile, the use of lignite and coal has been on a steady decline, together contributing roughly a quarter to gross generation, however, natural gas use for electricity generation has increased.

Like Germany, Spain's 2024 electricity grid mix remained strongly renewable, where wind and solar provided nearly half of annual electricity generation along with substantial hydropower. The rest was mainly provided by natural gas, used for flexibility, some nuclear generation and declining and smaller coal generation [4].

In 2024, Poland's mix was still dominated by coal, with hard coal and lignite together contributing to more than half of yearly electricity generation. Renewables, mostly onshore wind, followed by solar photovoltaic and some biomass, represented a rising but still minority portion. The rest of electricity generation relied on gas and some other sources [4].

2.3. Related Work and Positioning of This Study

Previous work on the electrification of industrial process heat and the use of thermal storage has primarily focused on technical feasibility and economic assessment against spot market prices [7]. To avoid the inclusion of cost components some studies analyse the storage in an off-grid system [8]. Whilst this is one of the factors affecting storage operation, further cost components added to the end-user electricity price can neutralize this arbitrage. In these studies, the added value of storage is typically quantified in terms of reduced electricity procurement costs and avoided CO_2 emissions. However, the majority of this literature abstracts from real end-customer price structures and assumes that industrial consumers purchase directly and exclusively at wholesale spot prices.

In parallel, there is an extensive body of literature on electricity tariff design, grid charges and levies for energy- and electricity-intensive customers [6, 9, 10]. These studies analyse how especially network charges are structured and how the costs are allocated across different grid users, what grid fee designs are used in different countries and their advantages and disadvantages, and rank industrial competitiveness between countries depending on their end-use industrial electricity price structure.

As for the challenges with end-use electricity prices with storage integration, different TES companies have expressed their obstacles when integrating their storage model in some countries due to their electricity cost regulations. In a Q&A conducted with ENERGYNEST's CEO Christian Thiel [11], he expressed that the biggest challenge and relevant policies for widespread adoption of TES are grid access, grid fees, and the speed of permitting approval for renewables, especially naming Germany.

Previous work by the authors [2] has investigated the industrial integration of an electric TES for process steam under detailed German industrial electricity regulation. That study explicitly included grid fees, levies, taxes and exemptions in the cost function and compared different procurement strategies, such as fixed-price contracts and Day-Ahead sourcing, for a range of storage sizes. It demonstrated that the business case for electric TES is highly sensitive to peak-based grid fees and their potential reduction. However, the analysis was confined to Germany and did not address how the same technology and industrial process would perform under different national tariff structures and power system emissions. The present study extends this line of work by embedding the electric TES in a common industrial case study and systematically comparing its economic and ecologic performance in three contrasting European countries – Germany, Spain and Poland – under realistic industrial end-user electricity prices (for 2024 regulations) and time-varying grid CO_2 intensities.

3. Methods

3.1. Optimisation Model

The industrial energy system is formulated as a mixed-integer linear programming (MILP) problem using the open-source energy modelling framework (oemof.solph) in Python 3.13. The model optimises the quarter-hourly operation of a combined gas boiler and electric latent heat storage system with electricity grid connection which supply an industrial heat and electricity profile over one full year. Perfect foresight of electricity demand, steam demand, and Day-ahead prices is assumed. All components are represented with linearised performance characteristics and fixed efficiencies. Part-load effects, temperature-dependent losses, degradation and maintenance outages are not modelled.

Decision variables include the gas boiler thermal output, the charging and discharging power of the TES, and the grid electricity import power. The baseline electricity demand of the case study paper company is treated as an exogeneous, non-shiftable profile. An additional variable represents the annual peak demand, which is used to calculate power-based network charges. The model is solved with the commercial solver Gurobi.

The primary objective is to minimise annual operating costs, to which a CO_2-related term can be added in CO_2-aware runs. The annual cost component is defined as the sum of gas fuel costs (C_t^{gas}), electricity energy costs (fixed contract for base demand $C_t^{el,base}$ and Day-ahead prices for TES charging $C_t^{el,TES}$), grid fees ($C_t^{network}$), taxes (C_t^{taxes}), charges ($C_t^{charges}$) and levies (C_t^{levies}) as defined in Equation 1:

$$\min C_{cost} = \sum_t \left(C_t^{gas} + C_t^{el,base} + C_t^{el,TES} + C_t^{network} + C_t^{taxes} + C_t^{charges} + C_t^{levies}\right). \tag{1}$$

For each timestep t let E_t^{el} be the total electricity drawn from the grid (for base load and TES charging) [kWh], E_t^{gas} be the gas energy used by the boiler [kWh], EF_t^{el} be the time varying grid CO_2 intensity for the country [$kgCO_2/MWh$] (see Section 3.3.1) and EF^{gas} the constant CO_2 intensity for gas [$kgCO_2/MWh$], then the total annual emissions ($CO_{2_{tot}}$) [$kgCO_2$] are:

$$CO_{2_{tot}} = \sum_t \left(EF_t^{el} \cdot E_t^{el} + EF^{gas} \cdot E_t^{gas}\right). \tag{2}$$

In CO_2-aware runs an internal CO_2 price (p_{CO_2}) is added to the minimization objective to define the new objective:

$$\min C_{cost} + p_{CO_2} \cdot CO_{2_{tot}}. \tag{3}$$

3.2. Energy System Description and Case Study

3.2.1. Energy System Model

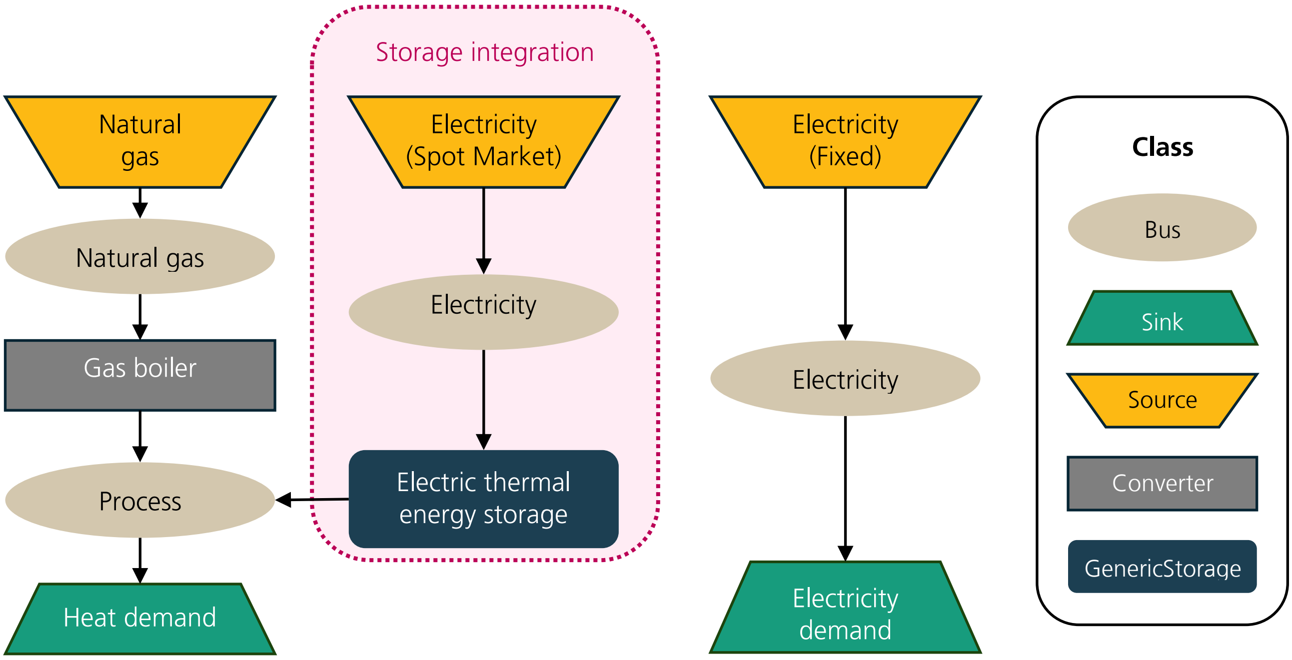

Figure 1. *Schematic of the Two Energy System Setups without/with Storage Integration in oemof.solph*

The industrial energy system configuration is identical in structure across all three countries. It consists of:

- A natural gas-fired boiler that can supply the entire process steam demand.
- An electric latent heat storage unit that can be charged from the grid and discharge steam into the same steam network as the gas boiler.

- A grid connection through which all electricity is imported. There is no on-site generation, and the grid connection is assumed to be adequate for any (charging) power represented in the model.

In the baseline configuration, the plant operates without TES, and the gas boiler meets the full steam demand while electricity is procured on a fixed-price contract for the base load. In the storage configuration, the same fixed contract continues to supply the base electricity demand, whereas TES charging is covered through to Day-ahead prices. Additional end-use cost components (grid fees, charges, taxes and levies) are applied to the total electricity import (fixed plus Day-ahead). This setup reflects a realistic mixed procurement strategy and isolates the role of TES as a flexible, price-responsive electricity consumer for steam generation. The two system setups can be seen in **Figure 1**.

3.2.2. Industrial Case Study

The case study is based on a synthetic medium-sized paper manufacturing company [2], representative of the packaging segment, which is one of the largest paper-consuming sectors in Europe [12]. Annual production is assumed at 100,000 t of paper. Based on literature data [12], the specific electricity consumption is set to 530 kWh/t and the specific fuel (heat) demand to 1528 kWh/t. This results in an annual electricity demand of approximately 53 GWh and an annual thermal energy demand of around 152.8 GWh.

Quarter-hourly time-series for electricity and steam demand are generated by scaling a synthetic industrial load profile from Sandhaas et. al [13] to the above annual values. The thermal energy demand is divided into three applications being space heating, hot water and process heat at various temperature levels. From the annual thermal energy demand of the company hence 149.3 GWh falls in the temperature range of < 100 °C and 100 – 500 °C which is attributed to the company's process heat (e.g. steam) demand. Further, the annual electricity demand has no application share for process heat, therefore it can be assumed, that the gas boiler covers the entire process steam demand. The steam is assumed to be supplied at a uniform quality, and constraints related to condensate return are ignored [2]. The same demand time series are used for all three countries in order to isolate the impact of country-specific energy prices, tariffs and emission factors.

3.2.3. Technology Modelling

The **natural gas boiler** is modelled as an oemof.solph Converter component with a constant thermal efficiency of 0.9 [14], converting gas energy into steam. The boiler is assumed to be already installed and boiler capacity sufficiently large to cover the full steam demand at any time. The model is free to dispatch it anywhere between zero and this maximum, subject to the economics of gas versus electricity.

The **electric TES** used in the optimization model is based on Fraunhofer UMSICHT's ISSDemo project storage in Germany. This project is co-funded by the European Union through the Clean Energy Transition Partnership (CETPartnership) and includes partners in Poland and Spain [2]. The ISSDemo project storage is a high-temperature (250 – 500°C) latent heat storage with ZnAl6 as phase change material in the current demonstration unit. It charges electrically through resistance heat bands placed around the storage container and discharges heat in form of steam at required process parameters. In the optimization model the GenericStorage component is parametrized to replicate the behaviour of the project storage. Parameters used in this study are currently confidential, however validated with internal flow models and commercially available electric TES [15]. The storage has a modular setup and charging and discharging power are modelled corresponding to its capacity. Additionally, the initial state of charge is assumed to be zero, and the final SOC is left free to avoid biasing the dispatch. The model permits simultaneous charging and discharging.

3.3. Data and Country-Specific Price and CO_2 Inputs

3.3.1. Energy Price Assumptions

Fixed-price gas and electricity costs for industrial consumers are represented through the use of Eurostat statistics for average non-household energy prices for each country. For natural gas, the dataset "Gas prices for non-household consumers - bi-annual data (from 2007 onwards)" is chosen and the consumption band I4 ("100 000 GJ to 999 999 GJ") is selected, which corresponds to large industrial users comparable to the case-study plant. The average with "all taxes and levies included" of the 2024 S1 and S2 reporting periods is taken and rounded to representative figures. This yields approximate industrial gas prices of 7 ct/kWh for Germany, 5 ct/kWh for Spain and 7 ct/kWh for Poland. In the model, these values are used as effective end-user gas prices and are kept constant over the optimization horizon.

For electricity, the dataset "Electricity prices components for non-household consumers - annual data (from 2007 onwards)" is selected and only the "Energy and supply" component is chosen, which reflects the wholesale energy cost and supplier margin but excludes network charges, taxes and most levies. The consumption band IF ("70 000 MWh to 149 999 MWh") is selected, which matches the annual electricity demand of the case-study plant if part of the thermal energy demand is covered by the electric TES. Using the reported 2024 values, energy-component prices of approximately 10 ct/kWh for Germany, 8.5 ct/kWh for Spain and 7.5 ct/kWh for Poland are obtained. These values are interpreted as the energy procurement component of the fixed-price electricity contract that covers the base electricity demand. Grid fees, taxes, charges and levies are modelled separately in the electricity cost function based on country-specific tariff structures, so that the full industrial end-user electricity price emerges endogenously from energy, grid and policy components. VAT is fully excluded from this analysis as it would not further influence the storage integration analysis.

Germany adds grid fees in form of energy- and (peak-)power-based network charges with 7000 – 7500 – 8000 full-load hours-dependent reductions corresponding to 20 – 15 – 10 %. The peak-power component and the corresponding reductions are supposed to be the dominant drivers in electricity usage [2]. The set prices in this case study are taken from the city Oberhausen 2024 price sheet for high-voltage grid users [16]. The power price is set to 83.06 €/kW and the work price to 0.46 €ct/kWh. Other components include an electricity tax which for industrial users corresponds to 0.0005 €/kWh and charges in forms of a concession fee with an industrial reduced value of 0.0011 €/kWh. The levies are composed of the §19 surcharge for special grid utilisation (0.00643 €/kWh for 1 GWh, for > 1 GWh: 0.00025 €/kWh), the CHP levy (0.00275 €/kWh for 1 GWh, for > 1 GWh: 15 % of 0.00275 €/kWh) and the offshore grid levy (0.00656 €/kWh for 1 GWh, for > 1 GWh: 15 % of 0.00656 €/kWh) [2].

In **Spain** the "6.2TD" TOU tariff for large industrial users was selected in which different calendar time zones are given with prices P1 – P6 from higher to lower. The time zones are split into the 24 hours for every month and separate for all weekends and holidays [3]. Grid fees are represented in form of tolls, which include an energy and a power component both with a set of six prices for the different time zones. Equally, the so-called system charges which are levies for renewable energy sources, capacity and adjustments have a power and energy component with P1 – P6 prices. On both grid fees and levies the reduced electricity tax of $5{,}11\% \cdot 0.15$ is imposed. Charges in form of adjustment services (imbalance penalties) are excluded from this study as perfect foresight is given, and any contracted power corresponds to the peak power in the optimization.

For the **Polish** use case the A23 large industrial tariff from Tauron was chosen, which includes three time-zones (summer/winter-dependant morning – afternoon – rest time zones) and a capacity window. It is setup of fixed and variable components. The fixed network charge of 15.64 PLN/kW/month and the variable network charge for the three TOU periods of 24.91 – 27.42 – 20.21 PLN/MWh form the grid fee component. Monthly power-prices refer to contracted power, which in the model was simplified to monthly peaks, similar to Spain. Charges include a transition charge (0.2 PLN/kW/month), a subscription charge (18 PLN/month) and a capacity charge (0.1267 PLN/kWh) which is applied to the energy consumed Mondays to Fridays from 07:00 to 21:59. Levies contain a CHP surcharge of 6.18 PLN/MWh and a quality surcharge of 31.41 PLN/MWh [5]. Industrial users are exempt from an additional electricity/excise tax which therefore is set to 0. The exchange rate was set to $1\ PLN = 0.23\ €$.

Spot market data is obtained from historical Day-ahead prices from the ENTSO-E Transparency Platform [4] for bidding zones DE-LU (Germany), PL (Poland) and ES (Spain) for the year 2024. The underlying sources for these datasets are the relevant power exchange markets: EPEX SPOT, TGE and OMIE respectively. Prior to Oct 2025 the EU-wide power exchange market only offered hourly Day-ahead products [17]. To match the temporal resolution industrial energy demand profiles (quarter-hourly), hourly prices are resampled quarter-hourly with the same price for each quarter of the hour. In the case of Germany, the data was already exportable in this format.

Time-varying grid CO_2 (equivalent) intensity are derived from ENTSO-E generation per production type data [4]. For each country and timestep, total electricity generation by production type is combined with production and country-specific emission factors [18] to yield a weighted average grid intensity [19]. This series is then aligned with the model timesteps. The same method is used for all three countries, ensuring a consistent comparison of emission impacts between them.

3.4. Scenario Design and Sensitivity Analysis

The scenario design combined the countries Germany, Spain and Poland with different respective operational and regulatory settings. For each country, the same reference case without electric TES is modelled, in which the gas boiler covers the full process steam demand and the fixed-price electricity contract supplies the entire electricity demand. This reference is used to quantify the incremental impact of adding the electric TES. In the storage cases, the reference case configuration remain the same and TES charging is exposed to Day-ahead prices. Furthermore, all additional end-use cost components (grid fees, taxes, charges and levies) are applied to the total electricity import. In all storage scenarios, the TES capacity is fixed at 100 MWh for all countries.

Several sensitivities are defined to isolate the impact of key assumptions. First, individual electricity price cost components are removed from cost calculations to observe which are the key drivers enabling a defossilised electrification of process heat.

Second, three different CO2-awareness runs are made: a pure cost-optimal run ($p_{CO_2} = 0\ [€/t]$), a moderate CO2-aware run ($p_{CO_2} = 50\ [€/t]$) and a high CO2-aware run ($p_{CO_2} = 150\ [€/t]$) to explore the trade-off between operating cost and CO2 emissions.

Third, a harmonised-price sensitivity is introduced in which all three countries are assigned the same gas, fixed-price electricity and Day-ahead prices, set equal to the German reference levels (Section 3.3.1) as well as corresponding emission factors. This sensitivity keeps country-specific grid fees, levies and charges unchanged, but removes differences in the underlying energy price levels, thereby disentangling the effect of price levels from the effect of tariff structures on the relative attractiveness of TES integration.

Across all scenarios and sensitivities, the system performance is evaluated using a consistent set of metrics. These include total annual operating costs, specific electricity cost split into its individual cost components, and cost savings relative to the reference system without TES. On the environmental side, total annual CO_2 emissions and the relative emission change compared to the reference are reported.

4. Results and Discussion

4.1. Cross-Country Comparison and Ranking

Table 1. *Results Overview for Germany, Spain and Poland comparing Reference Energy System without storage to Energy System with Storage Installation*

Month	Germany		Spain		Poland	
Storage Installation	no	yes	no	yes	no	yes
Total Cost [M€]	18.442	16.663	13.655	11.721	18.046	17.717
Base Electricity [M€]	6.830	5.577	5.361	5.312	6.434	6.101
Storage Charging [M€]	-	2.518	-	1.568	-	0.772
Gas [M€]	11.612	8.568	8.294	4.840	11.612	10.844
Total Electricity Consumpt. [GWh]	52.994	92.729	52.994	115.803	52.994	63.376
Base Electricity [GWh]	52.994	52.994	52.994	52.994	52.994	52.994
Storage Charging [GWh]	-	39.735	-	62.809	-	10.382
Max storage charge [MW]	-	12.951	-	44.851	-	17.365
Total Gas Consumption [GWh]	165.886	122.395	165.886	96.803	165.886	154.918
Peak Power [MW]	13.247	13.247	13.247	55.872	13.247	17.949
Total Emissions [kt CO_2]	78.708	73.783	73.061	48.328	92.780	92.570

Table 1 includes the results for the three countries Germany, Spain and Poland for the reference case without storage integration to the system including the TES. The energy price differences between the countries are visible when looking at the total cost for the reference case system. Germany has the highest total cost of around 18.4 M€, followed by Poland with 18 M€ and Spain with 13.7 M€. For all three countries the cost decreases when integrating the TES: Spain has a decrease of around 14.2 %, Germany of around 9.6 % and Poland has the smallest decrease of around 1.8 %. Total gas consumption is lowered correspondingly, and electricity consumption increases. The Spanish electricity price structure benefits the use of electricity during the cheaper Day-ahead hours as the set time zones for the tolls and system charges closely match the pricing of the Day-ahead market. The large price difference between P1 and P6 price time zones also incentivizes usage during typical timeframes with higher renewable penetration and less usage. For tariff 6.2TD the toll prices from P1 to P6 for the energy and power component are 0.011872 to 0.00009 €/kWh and 13.138413 to 0.238475 €/kW*a.

As for emissions, the order is similar, however whilst Spain shows a large drop in emissions of 33.9 %, Germany only has a moderate reduction of 6.3 % and Poland barely a reduction of 0.2%. This also stems from the electricity generation types per country and the specific grid emissions compared to the emission factor assigned to natural gas. Natural gas, which is used in the gas boiler for steam generation, has an emission factor of around 400 kgCO2eq/MWh. The average grid emission factor in Germany is 318 kg CO2eq/MWh, 93 kg CO2eq/MWh in Spain and 539 kg CO2eq/MWh in Poland. In Spain therefore, the TES enables strong electrification at both low cost and low emission hours. Most of the generation in Spain is considered emission-free. The data set contains 17 % generation through fossil gas, and the rest is mostly distributed between onshore wind, nuclear, solar and hydro ranked by percentage share [4]. The TES in Poland offers only marginal defossilisation due to the high grid emission intensity, which is highly reliant on coal with a much larger emission factor than natural gas. Germany's emissions only drop slightly due to the relatively CO2-intensive grid, but especially due to the emission-unrelated grid fee structure.

Whilst Polish peak power increases to 17.9 MW compared to the base electricity demand peak of 13.2 MW without storage, in Spain peak power rises to 55.9 MW. This stays economical as the Spanish cost component power terms per kW are relatively moderate. Spain is hence the only country fully exploiting maximum charging power of the storage. Interestingly, Germany remains at a peak power of 13.2 MW as the grid fees have a large factorial peak power component. This effect can be further seen when looking at the average yearly specific electricity price in **Figure 2**. Grid fees are reduced by activating one of the full-load hours rebates. Hence, storage charging and electricity usage is only increased when it does not increase the peak power of the system (base electricity + storage charging) and when the end-use electricity price is lower than gas price.

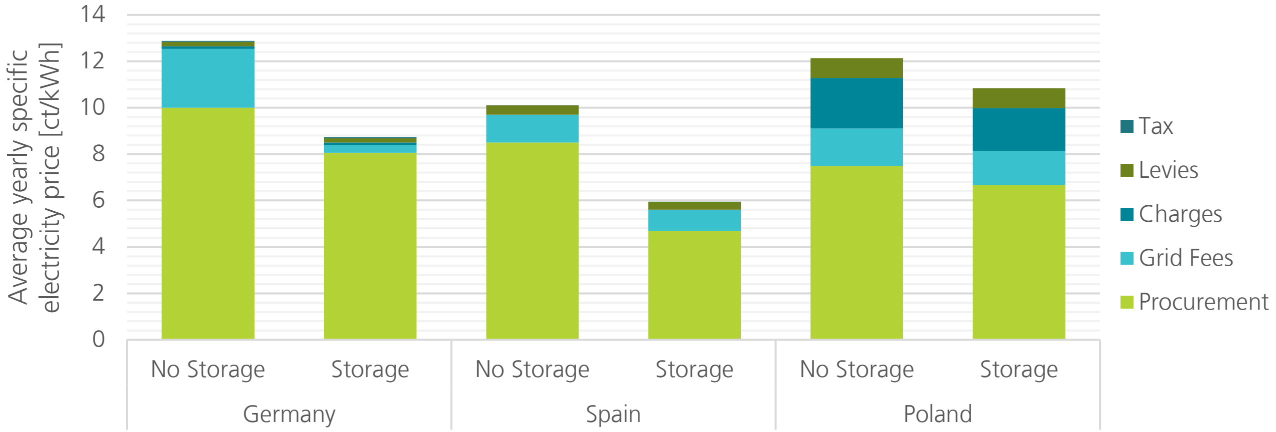

***Figure 2.** Average yearly specific electricity price [ct/kWh]: Comparison of Reference Energy System without Storage with Energy System including Storage for the countries Germany, Spain and Poland*

The average specific electricity price in Germany drops from a total of 12.89 ct/kWh, which is the highest price of the three countries, to 8.73 ct/kWh with most stemming from a decrease in grid fees through activation of full-load hour reduction followed by cheaper procurement. Spain's specific electricity price shows a large reduction from 10.12 ct/kWh to 5.94 ct/kWh. The storage strongly reduces average procurement price by largely exploiting low Day-ahead prices. Grid fees and system charges, which are both linked to yearly set time zones and assigned prices P1 – P6, also fall somewhat. In Poland the specific electricity price only drops from 12.14 to 10.85 ct/kWh, rewarding the least electrification flexibility through TES. Electricity procurement remains expensive relative to gas, especially when adding the fixed power-related charges and the capacity fee. Hence, the optimal solution in Poland only modestly increases electric heat and mainly stays on gas.

4.2. Sensitivity Analysis

Three sensitivity analyses were conducted to identify key drivers and reactions to different changes in the energy system. For all sensitivities the analysis was carried out within the system including the TES and compared to the reference system without storage and the base system with storage.

4.2.1. Sensitivity to End-user Price Components

In the first sensitivity analysis the individual end-user cost components, namely grid fees, levies, charges and taxes, were separately removed from the cost equation to identify the limiting factors for cost and emission reductions. From **Figure 3** (a) we can see that in all three countries removing grid fees from the cost equation offers the largest total cost reduction. In Germany removing grid fees lowers the costs from 18.4 M€ to 14.0 M€ (23.9 %) compared to the reference system without storage. In Spain, grid fees lower the total cost by 24.2 % to 10.3 M€ and in Poland by 9.5 % to 16.3 M€. Levies, charges and taxes only reduce the total cost minimally in Germany as they only consist of minor factorial energy components that don't alter the storage operation too much. Due to the price variations P1 – P6 in both the power and energy component of the system charges (under levies), these also offer some total cost reductions of 17 %. As charges are excluded in this analysis and the tax is also set very low for industrial consumers, the removal of these components barely alters the total cost. In Poland there is a tax exemption for industrial consumers, hence this cost component also does not change the total cost. However, the other components which contain both fixed and variable prices represent quite a large share of the specific electricity price (**Figure 2**). Correspondingly, removing charges lowers the costs to a similar level as for grid fee removal (16.5 M€) and levies slightly less to 17.2 M€.

Looking at total emissions (**Figure 3** (b)), the percentage difference in Germany and especially in Poland is even smaller. The order of importance of the different cost components remains the same but whilst in Germany only grid fees reduce emissions by 22.4 % compared to the reference case without storage, no cost component in Poland achieves a reduction higher than 1 % of total emissions. The emission-intensive Polish grid, relying mostly on coal (around 57 % [4]) with a higher emission factor that natural gas (for Poland

845.92 kgCO$_2$eq/MWh [18]) impedes a higher reduction through cost component removal. In the case of Spain, most of the emission reduction is already achieved through storage integration (33.9 %) and up to 7.6 % further reduction (in the case of grid fee removal) through the exclusion of the other cost components. This credits the Spanish end-use electricity price design as enabling both economic and ecological advantages.

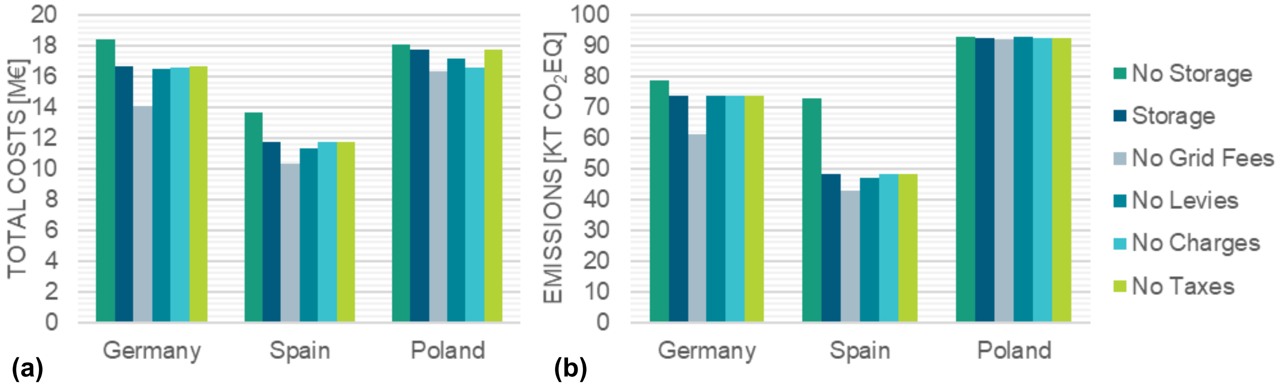

Figure 3. *(a) Total Costs and (b) Total Emissions of Sensitivity to End-User Price Components for the Countries Germany, Spain and Poland*

4.2.2. Sensitivity to CO$_2$ Awareness

In the second sensitivity analysis a CO$_2$-awareness was introduced for which a moderate (50 €/t CO$_2$) and high (100 €/t CO$_2$) CO$_2$eq price was set alongside the reference without CO$_2$-awareness. The objective remains the cost minimization function including the CO$_2$ cost term. The model hence implicitly attempts to reduce emissions as long as this maintains the lowest total cost.

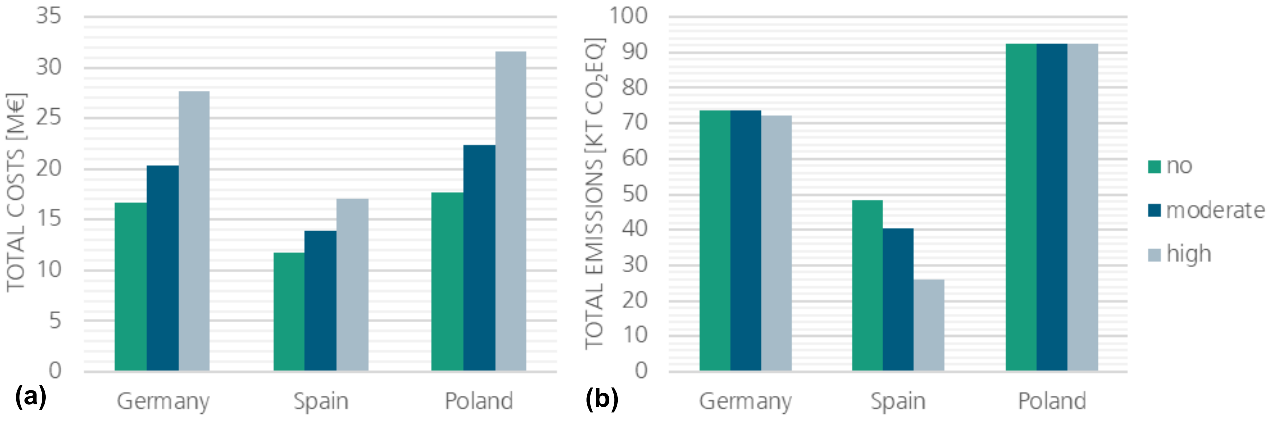

Figure 4. *(a) Total Costs and (b) Total Emissions of Sensitivity to CO$_2$-Awareness for the Countries Germany, Spain and Poland*

Figure 4 shows the results of the CO$_2$-awareness scenarios for total costs (a) and total emissions (b) for the countries Germany, Spain and Poland. The scenario with no CO$_2$ costs represents the base scenario with storage integration and both the moderate and high scenario include the storage in the energy system. For both Germany and Poland increasing the CO$_2$ price drastically increases costs (increase of 65.8 % for the high CO$_2$ cost in Germany and 78.3 % in Poland) yet have close to no emission reduction. In Germany there is only a mild change in storage operation, hence emissions barely change. In Poland, the emission-intensive grid and tariff structure neutralize the CO$_2$-signal. The most visible effect of adding CO$_2$-awareness can be seen in Spain where costs are increased by 18.9 – 46.1 % for the moderate – high case respectively in comparison to no CO$_2$ costs. In the CO$_2$-aware scenarios the Spanish case study has a strong electrification with lower related grid-emissions. Emissions are reduced by 16.5 and 46.5 % for the moderate and high case respectively.

4.2.3. Sensitivity to Harmonised Procurement and CO$_2$eq Conditions

In the third sensitivity all countries were set to have the same energy procurement prices (fixed gas, fixed electricity procurement, Day-ahead prices) as Germany alongside the corresponding grid emission intensities. This sensitivity aimed to isolate the effect of different prices for the countries from their general electricity cost structure and design.

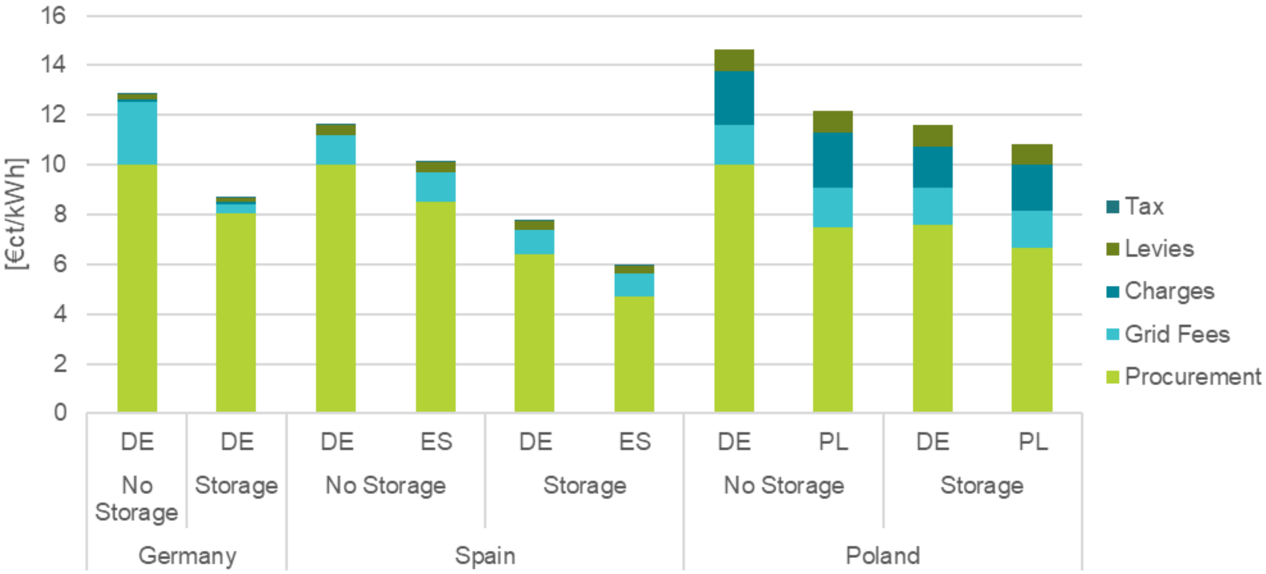

Figure 5. *(a) Total Costs and (b) Total Emissions of Sensitivity to Harmonised Procurement and CO2eq Conditions for the Countries Germany, Spain and Poland with DE, ES and PL referring to set country prices*

The German reference system was left unchanged and only the prices for Spain and Poland were changed. The Spanish case with German prices remains attractive and achieves lower specific electricity prices that the German reference system for both the energy system without and with storage. With total emissions at 64.9 tCO_2 German prices and grid emission intensities increase the Spanish case study emissions yet still achieve a large reduction in comparison to German emissions (see **Table 1**). Curiously, in the Polish case the storage becomes more attractive with German prices and carbon intensities. Storage integration reduces specific electricity price by 20.9 % compared to 10.7 % within the pure Polish framework. This shows the distinction between commodity and tariff design.

4.3. Implications

4.3.1. Country-specific drivers and implications

The results of the country comparisons and sensitivities show clearly that the economic attractiveness and ecological benefit of the TES is not primarily determined by wholesale or CO_2 prices but hinges on the structure and design of end-user electricity price. Whilst Day-ahead prices provide short-term price signals in all three countries, which the storage uses for orientation, these are passed through very differently to the end-user.

In Spain, these Day-ahead price signals are intensified by the 6.2TD tariff structure with six price time zones: large price differences between periods with P1 and P6 are reflected in both energy and power components of tolls (grid fees) and system charges (levies). In combination with a high PV-share the cheap and low-emission midday hours lead to low end-user prices. The storage can use this structure to charge almost exclusively in these cheap periods and simultaneously lower both costs and emissions. The CO_2 price works complementary by further increasing the difference between renewable and fossil generation periods.

In Germany the effect of the end-use price design is more subtle: The full-load hour rebate on grid fees dominates the economic assessment. The storage is used to optimize peak power and the yearly associated load hours which leads to a high reduction in grid fees. At the same time the grid remains relatively CO_2-intensive despite an increasing share of renewables, which makes additional electrification economically viable yet ecologically only affect in the medium-term. The CO_2-price is used here primarily to shift costs between gas and electricity but without altering the fundamental incentives of the grid fee regime.

In Poland the Day-ahead signals are nearly cancelled out through the combination of high energy- and power-dependent grid fees, a capacity-based charge and further levies. The resulting end-use electricity price remains relatively flat over time and is well above the price of gas in relation to the CO_2-intensity difference. Therefore, neither storage operation nor emissions react strongly to the CO_2-prices. The sensitivity to end-user price components shows that not the wholesale market but the national end-use price design is the dominant driver for or against additional electrification.

4.3.2. Implications for policy and industry

From an energy and climate policy perspective, the analysis demonstrates that the introduction of electrically charged TES into industrial steam systems is not a technical problem, but rather a regulatory one. In Spain, the 6.2TD tariff demonstrates how a combination of time-varying grid fees and system charges, high levels of renewable generation, and a moderate CO_2 price can generate strong investment signals for industrial flexibility. The results suggest that continuing and cautiously refining this design – for example, by providing targeted relief to electricity-intensive consumers during periods with particularly high renewable energy generation – can further accelerate storage integration and process heat electrification without increasing system costs.

In Germany, the study makes it clear that the existing grid fee and levy system already offers significant economic scope for load management and storage operation, but that this scope is only limitedly CO_2-oriented. Storage is primarily used to optimise full-load hours and power prices, rather than to specifically utilise low-CO_2 hours. For policymakers, this means that a stronger linkage of grid tariffs, levies and electricity tax to time-varying CO_2 intensities could significantly increase the contribution of industrial storage to defossilisation without calling into question the fundamental logic of cost pass-through.

For Poland, the results suggest that under the current conditions – a coal-heavy generation mix and heavily burdened end-user electricity prices – additional electrification of process heat is hardly economically or ecologically viable, even with high CO_2 prices. For policymakers and regulators, this implies a clear sequence of steps: First, the generation structure and end-user price components (in particular capacity charges as well as levies) must be reformed so that electricity is not permanently disadvantaged compared to gas for the same climate impact. Only then can electrical storage technologies such as the TES system under consideration realise their flexibility potential.

For technology providers and industrial companies, the study provides a decision-making aid for market prioritisation. Markets with high renewable penetration and pronounced temporal differentiation of end-user prices (such as Spain) are ideally suited for early storage and PtH projects. In markets with complex but non-CO_2-oriented grid tariff regimes (like Germany), the business case lies more in grid tariff optimisation, which suggests different designs and operational strategies. In markets with high, largely CO_2-insensitive electricity costs (such as Poland), storage projects should be closely linked to regulatory reform processes to avoid misallocation of investment.

4.4. Limitations and Future Work

The chosen methodology has proven suitable for making country- and price-component-specific effects transparent. Nevertheless, the study is limited by its consideration of a single industrial case with synthetic timeseries, a single storage technology and given plant and storage sizes. It also didn’t take into account capital expenditures of the storage. The end-use electricity price design was simplified by excluding imbalance penalties in Poland and Spain and contracted power was modelled through peak power.

Future work should address additional sectors, alternative storage and PtH concepts, investment-related dimensioning (storage size, connected load), as well as the explicit modelling of contractual output limits and future tariff and CO_2 price paths. Also, a generalization of end-use electricity designs to depict different country structures and expand assumptions on the attractiveness of TES integration into industry is planned. Lastly, new scenarios will include onsite renewable energy generation with PPAs adding realistic industrial conditions and combinations.

5. Conclusion

This study shows that the operational economic and environmental attractiveness of thermal energy storage for industrial process steam is less defined by the technology itself but by market and regulatory conditions. Through an industrial case study of a paper manufacturing company with the same heat and base electricity demand for the countries Germany, Spain and Poland the integration of the storage technology could be assessed under 2024 realistic end-use electricity prices.

In Spain the combination of high PV generation, distinct time-variable grid fees and system charges as well as moderate CO_2 intensities lead to the highest effects. The storage enabled a significant shift of process heat to low-cost, low-emission midday hours, significantly reduced overall costs and cut emissions by up to a third. Germany demonstrates that storage can be economically attractive even in a less defossilised electricity system: here, the main benefit stems from the reduction in grid fees based on full-load hours, whilst the reduction in emissions remains limited due to the grid’s relatively high CO_2 intensity compared to gas. In Poland, by contrast, the combination of a coal-heavy electricity mix, high energy- and power-related grid fees, and capacity-oriented charges prevented additional electrification via storage from being economically or environmentally viable – the model electrified heating there only marginally.

The sensitivity analyses underpin these results and isolate the dominant drivers: removing individual price components shows that in Germany and Spain, the structure of grid fees and system charges in particular determined the intensity of storage deployment, whilst in Poland the impact was marginal. CO_2 awareness sensitivity confirms that an internal CO_2 price is only an effective control instrument if a sufficiently defossilized grid and flexible end-user prices are in place: in Spain, a high CO_2 price leads to significant additional electrification and emission reductions, in Germany, to moderate adjustments and in Poland, the effect is virtually non-existent. Harmonising the energy and emissions landscape with German values also illustrates that the picture in Poland improves as soon as electricity price levels and emission factors are aligned – and that tariff design and the commodity side are separate but equally important levers.

Overall, the study demonstrates that industrial heat storage is not merely a technical flexibility option, but one that is clearly dependent on regulation – and that a technical assessment without consideration of the relevant price and emissions regime can lead to misleading conclusions.

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