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Will the European Union's emission trading system drive industrial steam electrification?

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HIGHLIGHTS

- Historical carbon prices have only reduced 8.28 % of industrial CO_2 emissions.
- Projected carbon prices will achieve only 34 % of CO_2 reduction by 2030 instead of 55 %.
- Full electrification by 2050 requires average carbon prices to reach 237.2 €/t CO_2.
- Industrial energy costs increase by 6.69 % even with balancing market participation.

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ABSTRACT

Driven by the European Union's climate-neutral ambitions, industries are being urged to electrify fossil fuel-based technologies. Historically, fossil fuels were the preferred choice due to their lower cost compared to electricity. However, as carbon allowance prices under the European Union's Emission Trading System continue to rise, industries are experiencing a substantial increase in their energy costs. The European Union anticipates that if these prices increase sufficiently, the cost gap between fossil fuels and electricity will close, encouraging a shift toward full electrification. In this paper, based on the consumption profiles of two large plastic manufacturing companies, we demonstrate that projected carbon prices will be insufficient to achieve the European Union's targeted 55 % of CO_2 reduction by 2030. Instead, we estimate a reduction of only 34 %. Moreover, we calculate that full electrification can be incentivized by 2050, but only if carbon allowance prices reach 237.2 €/t CO_2, on average. Nevertheless, this shift would significantly increase the energy costs for industrial companies. Even when participating in balancing markets, results indicate a net energy cost increase of 6.7 %, compared to their current costs. These findings highlight the need for policy measures beyond carbon pricing to protect industrial competitiveness and achieve decarbonization goals.

1. Introduction

The European Union (EU) has committed to ambitious climate targets under the European Green Deal, aiming for a 55 % reduction in greenhouse gas (GHG) emissions by 2030 and climate neutrality by 2050 (European Commission, 2019). To facilitate this transition, the EU established the Emissions Trading System (EU–ETS) in 2005 as a cap-and-trade mechanism designed to regulate carbon emissions through the allocation and trading of emission allowances (Fontini and Pavan, 2014). Initially, the EU allocated free allowances to mitigate opposition, based on historical emission levels, but this led to an oversupply, causing a significant drop in the carbon allowance prices (EEX, 2024a). In response, the EU gradually reduced the volume of free allowances to ensure a steady rise in carbon prices, aiming to strengthen the financial incentive for decarbonization (European Environment Agency, 2024).

Whether this climate policy succeeds will largely depend on the ability of carbon prices to generate sufficient economic pressure to drive decarbonization in high-emission sectors, such as the industry, which was responsible for 59 % of the EU's greenhouse gas emissions in 2022 (Eurostat, 2025). In particular, the plastic sector contributed 193 million tonnes of CO_2, representing 25.9 % of total industrial emissions (European Environment Agency, 2024; Eurostat, 2023). A substantial portion of these emissions occur during two key stages within the plastic

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manufacturing sector: the production of raw plastic polymers (e.g., ethylene, propylene) and the subsequent transformation of these polymers into plastic products through processes such as extrusion and molding (Khripko et al., 2020). Both stages require substantial thermal energy, much of which is delivered in the form of steam (Shen et al., 2020). This steam is typically generated on-site using fossil fuel-fired boilers (e.g., natural gas) (Khripko et al., 2020; Shen et al., 2020). The combustion of natural gas in these boilers represents a major direct source of CO_2 emissions within plastic manufacturing facilities, highlighting the central role of steam generation systems in the sector's carbon footprint.

Given the plastic companies' significant contribution to industrial emissions, technological interventions (such as replacing gas-fired boilers with electric alternatives) offer a pathway to decarbonization. However, this transition brings several challenges. Beyond the upfront capital investment required for the new equipment, companies must operate with higher energy prices (as overall, electricity is more expensive than gas; EEX, 2024b; ENTSOE, 2024), which can compromise economic viability. These financial pressures contribute to a general reluctance among industrial players to adopt electrification strategies, despite increasing regulatory and market pressures. Yet, as carbon prices under the EU–ETS continue to rise, the relative cost of using gas increases, pushing industries to consider low-carbon alternatives. In this evolving context, industrial companies are increasingly engaging with policymakers to identify feasible decarbonization pathways that align with both climate goals and industrial resilience.

One promising approach for mitigating the cost burden of electrification involves leveraging operational flexibility to participate in electricity balancing markets (Herre et al., 2020). For instance, a plastic manufacturing company that installs an electric boiler alongside its existing gas boiler can achieve a hybrid configuration that allows flexible steam generation (Cantu Rodriguez et al., 2024). In such a setup, the company can adjust the operation of the electric boiler in response to grid conditions by temporarily increasing or decreasing its electricity consumption. This flexibility can be monetized through participation in balancing markets, where companies are compensated for providing balancing services (Consentec GmbH, 2022). In this way, electrification can become a potential revenue stream, thereby improving the economic case for decarbonization.

1.1. Related work

Research on carbon pricing mechanisms, particularly EU–ETS, has primarily examined short- to medium-term effects on industrial production, emissions, and competitiveness. For example, Fontini and Pavan (2014) found that the EU–ETS led to a 9.19 % reduction in CO_2 emissions between 2005 and 2010 within Italian pulp production companies. Similarly, Lundgren et al. (2015) researched the Swedish pulp and paper industry between 1998 and 2008 and concluded that both the EU–ETS and Sweden's carbon tax contributed to improvements in productivity and technological innovation. In terms of competitiveness, Demailly and Quirion (2008) reported that historical carbon prices during Phase II of the EU–ETS resulted in minimal competitive disadvantage within the iron and steel sector, challenging the notion that environmental regulation necessarily harms industry performance. Additionally, Scholtens and van der Goot (2014) conducted a cross-sectoral analysis of firm valuations between 2008 and 2011, where they found a small but statistically significant positive effect of the EU–ETS on company value, extending beyond the power sector to other regulated industries.

While these studies provide valuable insights into the initial phases of the EU–ETS, there is a growing need to examine its long-term influence on industrial decarbonization. For instance, research conducted by Hoffmann (2007) on the system's effect on green investment decisions yielded inconclusive findings. However, with carbon prices continuing to rise, industries are facing increased financial pressure to adopt low-carbon technologies. This highlights the need for updated analyses to determine whether current carbon prices are more effective in encouraging CO_2 emission reductions. Furthermore, since the EU can influence the carbon market by adjusting the supply of allowances, identifying the carbon price levels required to achieve its climate targets (55 % CO_2 reduction by 2030 and full decarbonization by 2050) can provide valuable insights and guide future policy decisions.

In parallel, several studies explore how industrial companies can provide balancing services. The work of Gade et al. (2024a) shows how a zinc galvanizing process within the metallurgy industry can participate in the Danish Frequency Containment Reserve (FCR), as well as in the manual Frequency Restoration Reserve (mFRR) markets. Their results indicate that the obtained monetary revenues can pay back the necessary investment in the power control of the furnace within one year. Similarly, Herre et al. (2020) simulate the participation of a paper mill in the Norwegian FCR market. Flexibility potential from thermostatically controlled loads in supermarket freezers is analyzed by Gade et al. (2024b), showing their applicability to the mFRR market. Additionally, Zhang et al. (2018) examine how cement production mills, supported by onsite energy storage, can deliver balancing services.

1.2. Contributions

This paper examines the impact of historical EU–ETS carbon price trends (from 2019 to 2024) on the energy costs and CO_2 emissions of two large plastic manufacturing industries that depend on steam for their production processes. By analyzing historical consumption profiles and energy prices, we evaluate whether rising carbon allowance prices have successfully reduced the cost gap between gas and electric steam production, thereby encouraging a shift toward cleaner technologies. Furthermore, based on forecasted electricity and gas prices, we estimate the average carbon allowance price required for these companies to meet a 55 % of CO_2 reduction by 2030 and full decarbonization by 2050, as the EU ambitions. In addition to these cost and emission dynamics, we explore the potential economic revenue plastic manufacturing companies could achieve by offering flexibility in the balancing market. More specifically, we examine participation in the mFRR and automatic Frequency Restoration Reserve (aFRR) markets due to the ramping capability of the gas boiler. We quantify the potential revenues companies could generate through this approach and investigate whether this business model can offset the energy cost increase driven by the EU–ETS. By providing a comprehensive evaluation of carbon pricing, industrial energy costs, and market-based flexibility strategies, this paper offers critical insights into the effectiveness of the EU–ETS and the challenges industries face in the transition toward electrification.

The specific research questions (RQs) that we aim to answer in this paper are as follows:

- RQ1: How have historical carbon allowance prices influenced the energy costs of plastic manufacturing industries? To what extent have they incentivized CO_2 emission reductions?
- RQ2: What are the average carbon allowance price levels required for plastic manufacturing companies to achieve 55 % of CO_2 emission reductions by 2030? And for complete elimination by 2050?
- RQ3: To what extent can industries reduce energy costs through acquired demand-side flexibility? Do these strategies affect the overall CO_2 emissions?

We elaborate on the methodological approach in Section 2, covering the dataset used and the mathematical models applied. The results are displayed in Section 3 and discussed in Section 4. Finally, in Section 5, we summarize our findings and offer future directions.

2. Methodological approach

This section outlines the research approach we followed to evaluate the decarbonization potential and economic consequences of electrifying steam production in the plastic manufacturing sector. Section 2.1 summarizes the input data, while Section 2.2 describes the modeling framework used to simulate scenarios, estimate costs, and evaluate balancing market revenues.

2.1. Input data

Our calculations rely on the historical steam and electricity consumption data from two large Luxembourgish plastic manufacturing companies, in one-hour resolution for a duration of one year.

2.1.1. Spot prices

We operate under the assumption that both electricity and gas costs are entirely subject to day-ahead spot markets, where we use historical prices from the years 2019 to 2024 (EEX, 2024b; ENTSOE, 2024), as represented in Fig. 1.

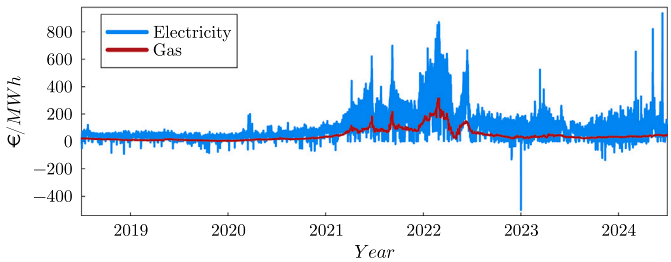

Fig. 1. Day-ahead spot prices (DE/LU) (EEX, 2024b; ENTSOE, 2024).

Regarding future prices, ENTSO-E has developed electricity spot price forecasts as part of the "Ten-Year Network Development Plan (2024)" scenarios. These forecasts are generated using a Pan-European dispatch model that simulates hourly market-clearing across the continent. The model accounts for the variations in future weather conditions, renewable generation output, levels of electricity demand, adoption of technology, and sectoral integration. The 2030 projections are based on the "National Trends^{+}" scenario, which incorporates EU Member States' policy commitments and infrastructure developments. Fig. 2 illustrates the resulting price trajectories. Electricity prices are expected to exhibit considerable volatility, with an average value of 65.4 €/MWh. For consistency, gas prices are taken from the same scenario assumptions, with a price of 22.7 €/MWh. Under this scenario, gas prices remain lower than electricity prices approximately 85.6 % of the time.

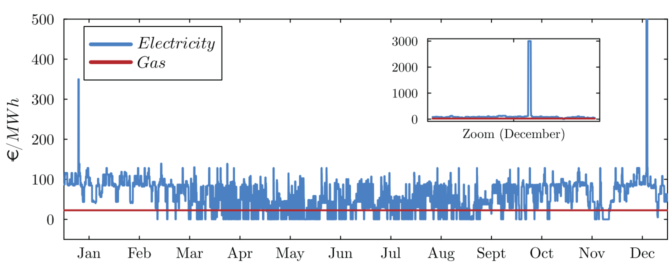

Fig. 2. Forecasted 2030 spot prices (DE/LU) (ENTSO-E/ENTSO-G, 2024).

On the other hand, the year 2050 includes six scenarios in total, based on three climate years (1995, 2008, and 2009) and two distinct pathways to meet the EU's climate targets: Distributed Energy (DE) and Global Ambition (GA) (ENTSO-E/ENTSO-G, 2024). The selection of 1995, 2008, and 2009 as representative climate years is based on a rigorous statistical assessment conducted by ENTSO-E, using 30 years of hourly meteorological data from the Pan-European Climate Database (ENTSO-E/ENTSO-G, 2024). This analysis was designed to capture the range of variability in weather conditions that influence both electricity demand and renewable generation. Each year includes 8760 hourly values per region, providing a detailed picture of temporal and spatial climate variation across Europe. To ensure that the selected years are statistically representative and not arbitrarily chosen, ENTSO-E applied the K-Medoids clustering technique using Euclidean distance to group climate years based on residual load distributions (ENTSO-E/ENTSO-G, 2024). This method allowed the identification of three climate years that together captured distinctly relevant operational conditions for the power system.

In particular, the year 2008 was selected as a balanced or typical year, representing average levels of wind availability, solar irradiation, and temperature conditions. In contrast, 1995 was chosen to represent a cold year with high heating demand and correspondingly high electricity load, combined with low wind and solar generation. The year 2009, on the other hand, was identified as one of the most stressful years in terms of supply-side conditions, due to the occurrence of a Dunkelflaute (a prolonged winter period of very low wind and solar generation) posing a challenge to the system's flexibility and ability to meet demand with renewable sources.

In addition, the Distributed Energy scenario focuses on local, decentralized, and consumer-driven energy solutions. It emphasizes the deployment of small-scale rooftop solar panels, local wind projects, and decentralized electrolysis. In this pathway, consumers play an active role by adopting advanced technologies such as heat pumps and electric vehicles, and by participating in demand response initiatives. In contrast, the Global Ambition scenario targets the EU's climate goals through centralized, large-scale projects. It envisions the development of extensive offshore wind farms and large solar farms but assumes a less active role for individual consumers in the energy transition. The resultant spot prices are displayed in Fig. 3 for each of the described scenarios.

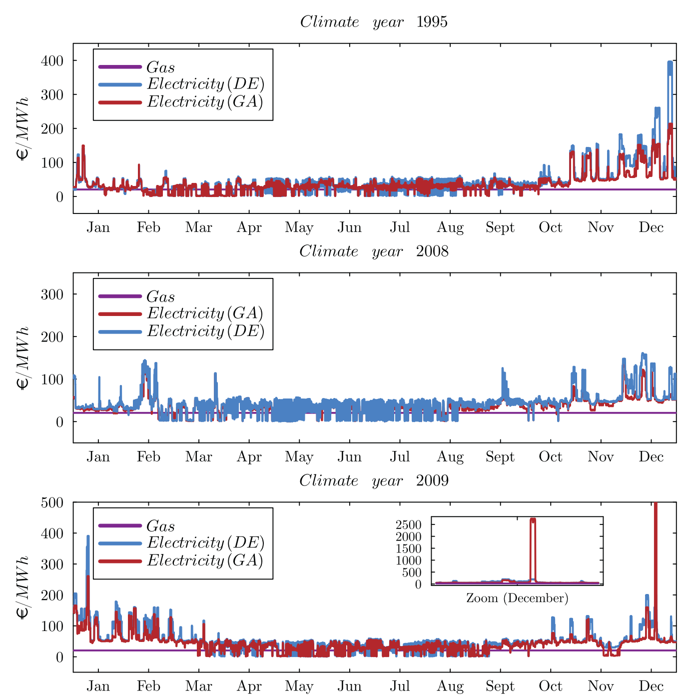

Fig. 3. Forecasted 2050 spot prices (DE/LU) (ENTSO-E/ENTSO-G, 2024).

2.1.2. Tariffs

Companies do not solely pay the day-ahead spot price; they are also subject to various tariffs and fees that significantly impact their total energy costs. Our analysis accounts for network costs, including both energy-based and peak demand tariffs, as well as government levies and utility-specific surcharges. Table 1 presents all the tariffs applied in our calculations, established by Luxembourg's System Operator (CREOS) (CREOS, 2023a,b).

Table 1
Network and government tariffs for the year 2024 (CREOS, 2023a,b).

Tariff	Company 1		Company 2	
(a1) Utility's electricity purchase fee	1.0000	€/MWh	1.0000	€/MWh
(a2) Government's electricity usage fee	0.9000	€/MWh	1.4000	€/MWh
(a3) Energy network fee for electricity	0.0239	€/kWh	0.0239	€/kWh
(a4) Capacity network fee for electricity	27.020	€/kW	27.020	€/kW
(b1) Utility's gas purchase fee	1.0000	€/MWh	1.0000	€/MWh
(b2) Government's gas usage fee	0.9000	€/MWh	0.9500	€/MWh
(b3) Energy network fee for gas	0.0587	€/Nm^3	0.0587	€/Nm^3
(b4) Capacity network fee for gas	9.7250	€/kW	5.5677	€/kW

2.1.3. European Union emission trading system

Table 2 displays the average carbon allowance prices from 2019 to 2024. Between 2019 and 2020, prices remained relatively low and stable. However, as the EU strengthened its climate policies and reduced the number of available allowances, prices significantly increased between 2021 and 2023. In 2024, the average price slightly declined to €65/t CO_2. Finally, since the EU plans to continue decreasing the free allowances, carbon prices are forecasted to increase until 150 €/t CO_2 by 2030 (BloombergNEF, 2024; Pahle et al., 2022).

Table 2
Average carbon allowance prices (2019–2024) (BloombergNEF, 2024; Pahle et al., 2022; Statista, 2024).

Year	Average EU–ETS
2019	24.58 €/t CO_2
2020	24.61 €/t CO_2
2021	52.25 €/t CO_2
2022	80.32 €/t CO_2
2023	83.66 €/t CO_2
2024	65.00 €/t CO_2
2030	150.0 €/t CO_2

2.1.4. Balancing market marginal prices

A detailed analysis of historical marginal prices in the joint German - Luxembourg (DE/LU) balancing markets is provided in Appendix A.1 and Appendix A.2. This includes capacity and energy prices for both mFRR and aFRR markets from 2020 to 2024, along with activation frequency and observed trends.

2.2. Modeling approach

This subsection describes the modeling framework used to quantify the economic impacts of electrifying steam production. The model integrates the input data described in Section 2.1 to simulate different electrification scenarios, compare energy cost outcomes, and estimate potential revenues from participation in balancing markets.

2.2.1. Steam production with gas-boiler

Consider an industrial facility that operates a gas boiler to produce s_t kg of steam for each hour $t \in \mathcal{T}$ for manufacturing purposes. Based on discussions with industry representatives and supported by technical literature, we assume that the recirculation water returns at 80 °C (Watertech of America, 2023; Bhatia, 2023), and that steam is generated at 16 bar (Clayton Industries, 2025; Ramram et al., 2025; The Engineering ToolBox, 2003). Under these conditions, the historical consumption of the gas boiler g_t (MWh) can be calculated as follows:

$$g_t = \frac{s_t \cdot (h_{s,16} - h_{w,80})}{k_1 \cdot \eta^{gas}} \tag{1}$$

where $h_{s,16}$ and $h_{w,80}$ are the enthalpies of the steam and recirculation water, respectively. Moreover, η_{gas} is the efficiency of the gas boiler, and k_1 is a conversion factor defining that $3.6 \cdot 10^6$ of kJ corresponds to 1 MWh of energy. Additionally, the company uses l_t^{elec} electricity (in MWh) for other manufacturing purposes for each time $t \in \mathcal{T}$. Assuming that this industry is subject to day-ahead spot prices, we can calculate its energy costs. Firstly, the energy cost associated with the utilization of the gas boiler can be determined using Eq. (2):

$$P^{gas}_{floating} = \sum_{t \in T} g_t \cdot (\lambda_t^{gas} + b_1) \tag{2a}$$

$$P^{gas}_{gov} = \sum_{t \in T} g_t \cdot b_2 \tag{2b}$$

$$P^{gas}_{energy} = \sum_{t \in T} g_t \cdot (k_2 \cdot b_3) \tag{2c}$$

$$P^{gas}_{power} = pk^{gas} \cdot b_4 \tag{2d}$$

$$P_{gas} = P^{gas}_{floating} + P^{gas}_{gov} + P^{gas}_{energy} + P^{gas}_{power} \tag{2e}$$

$P^{gas}_{floating}$ represents the cost of gas use which is subject to the day-ahead gas spot prices (λ_t^{gas}, in €/MWh) plus the fixed supplier's fee (b_1, in €/MWh). Additionally, P^{gas}_{gov} represents the cost of the government's taxes subject to fee b_2, in €/MWh. Moreover, P^{gas}_{energy} and P^{gas}_{power} are network energy and capacity costs respectively, where k_2 represents a conversion factor transforming MWh of natural gas to Nm^3, b_3 is the network energy fee in €/Nm^3, pk^{gas} represents the annual gas power peak of the industry in MW, and b_4 is the network capacity fee, in €/MW. Therefore, the total cost of generating steam with the gas boiler (P_{gas}) is the sum of all individual costs.

Regarding the electricity costs, we can follow the same principle using Eq. (3), where $P^{elec}_{floating}$ represents the energy cost associated with the electricity utilization subject to the day-ahead electricity spot prices (λ_t^{elec}, in €/MWh), plus the supplier's fixed fee (a_1, in €/MWh). P^{elec}_{gov} represents the government fees of using electricity subject to the fee a_2, in €/MWh. Moreover, P^{elec}_{energy} is the network energy cost subject to fee a_3, in €/MWh, and P^{elec}_{power} represents the network capacity costs subject to the peak yearly electricity power pk^{elec} in MW and fee a_4, in €/MW.

$$P^{elec}_{floating} = \sum_{t \in T} l_t^{elec} \cdot (\lambda_t^{elec} + a_1) \tag{3a}$$

$$P^{elec}_{gov} = \sum_{t \in T} l_t^{elec} \cdot a_2 \tag{3b}$$

$$P^{elec}_{energy} = \sum_{t \in T} l_t^{elec} \cdot a_3 \tag{3c}$$

$$P^{elec}_{power} = pk^{elec} \cdot a_4 \tag{3d}$$

$$P_{elec} = P^{elec}_{floating} + P^{elec}_{gov} + P^{elec}_{energy} + P^{elec}_{power} \tag{3e}$$

Therefore, we calculate the current energy cost of the industry (P_{ref}) by summing the gas and electricity costs.

$$P_{ref} = P_{gas} + P_{elec} \tag{4}$$

The energy cost computed in Eq. (4) excludes the impact of carbon allowance prices. To assess the effect of historical carbon prices on the industry, Eq. (5) determines the additional cost imposed by the EU–ETS.

$$P_{CO_2} = \sum_{t \in T} g_t \cdot k_3 \cdot \lambda^{co2} \tag{5}$$

This is done by calculating the company's total CO_2 emissions, using the conversion factor k_3, which specifies that natural gas emits 0.20196 tonnes of CO_2 per MWh (IPCC, 2006), along with the average yearly historical carbon allowance price (λ^{co2}). Consequently, when accounting for EU–ETS, we should add the carbon emission cost (P_{CO_2}) to the original company's energy cost (P_{ref}), to calculate the final energy cost of the company which is subject to carbon allowance prices (P^{ETS}_{ref}).

$$P^{ETS}_{ref} = P_{ref} + P_{CO_2} \tag{6}$$

2.2.2. Steam production with electric boiler

The industrial facility has the option to purchase an electric boiler to replace the gas boiler for steam generation, thereby achieving full electrification of its manufacturing processes. This strategy enables decarbonization without reducing production output, an essential condition explicitly stated by the companies consulted in this study and adopted by other industrial companies as part of their decarbonization efforts (Hydro, 2025). When relying solely on an electric boiler, the total electricity demand will comprise the original electrical load (l_t^{elec}) plus the additional load required to produce steam (e_t). Similarly to Eq. (1), we can calculate the electric load required by the boiler to produce s_t amount of steam using Eq. (7), but with the efficiency of the electric boiler (η^{elec}).

$$e_t = \frac{s_t \cdot (h_{s,16} - h_{w,80})}{k_1 \cdot \eta^{elec}} \tag{7}$$

Consequently, the new energy cost of producing the steam with the electric boiler (P_E) can be determined using the same approach as before (refer to Eq. (3)), but with an increased electrical load (l_t^{new}).

$$l_t^{new} = l_t^{elec} + e_t \tag{8}$$

By knowing the reference energy cost of the industry (P_G), the additional cost associated with the EU–ETS (P_{CO_2}), and the new energy cost of using only the electric boiler (P_E), we can calculate the price increase the industry would incur when fully electrifying its steam production, with and without the EU–ETS.

2.2.3. Partial steam electrification

By purchasing an electric boiler, the company can partially electrify its steam production, utilizing both the existing gas boiler and the newly acquired electric boiler (Cantu Rodriguez et al., 2024). As a result, the industry gains operational flexibility to produce steam, which can be harnessed to optimize total energy costs through the strategic adjustment of the boilers' schedules. Considering day-ahead spot prices, network energy and capacity tariffs, as well as utility and government fees, the following optimization model determines the optimal production schedules for the electric (e_t) and gas (g_t) boilers to minimize the total energy costs of the industry (see Eqs. (9a) and (9c)). By strategically adjusting the boilers' production schedules, the model not only adapts to day-ahead spot prices, but also adjusts the peak power demands of the gas (pk^{gas}) and electric boilers (pk^{elec}) to reduce network capacity charges. These power peaks are calculated based on the maximum power consumption over the year and constitute a significant portion of the final energy costs. Finally, to evaluate the effect of the EU–ETS within this scenario, we will run the optimization model with Eq. (9d) and without. This approach enables us to quantify the difference in energy costs and CO_2 emissions resulting from the inclusion of carbon allowance prices.

$$\min_{e_t, g_t, p^{elec}, p^{gas}} \sum_{t \in T} (e_t + l_t^{elec}) \cdot (\lambda_t^{elec} + a_1 + a_2 + a_3) \tag{9a}$$

$$+ \sum_{t \in T} g_t \cdot (\lambda_t^{gas} + b_1 + b_2 + k_2 \cdot b_3) \tag{9b}$$

$$+ (pk^{elec} \cdot a_4) + (pk^{gas} \cdot b_4) \tag{9c}$$

$$+ \sum_{t \in T} g_t \cdot k_3 \cdot \lambda^{co_2} \tag{9d}$$

$$s.t. \quad 0 \le e_t \le \overline{E}, \qquad \forall t \in \mathcal{T} \tag{9e}$$

$$0 \le g_t \le \overline{G}, \qquad \forall t \in \mathcal{T} \tag{9f}$$

$$e_t \cdot \eta_{elec} + g_t \cdot \eta_{gas} = \frac{s_t \cdot (h_{s,16} - h_{w,80})}{k_1}, \qquad \forall t \in \mathcal{T} \tag{9g}$$

$$g_t - g_{t-1} \le \overline{\delta}, \qquad \forall t \in \mathcal{T} \setminus \{t_0\} \tag{9h}$$

$$g_{t-1} - g_t \le \underline{\delta}, \qquad \forall t \in \mathcal{T} \setminus \{t_0\} \tag{9i}$$

$$e_t + l_t^{elec} \le pk^{elec}, \qquad \forall t \in \mathcal{T} \tag{9j}$$

$$g_t \le pk^{gas}, \qquad \forall t \in \mathcal{T} \tag{9k}$$

However, even though the optimization model can choose between using gas or electricity, it must respect the electric ($\overline{E}$) and gas ($\overline{G}$) boiler's capacities (see Eq.(9e) and (9f)). In addition, since we assume that the steam consumption (s_t) is inflexible, we must respect the historical steam consumption values (see Eq.(9g)), as well as the ramping capability of the most restrictive boiler, which is the gas boiler (see Eq. (9h) for ramp up and (9i) for ramp down limitation). Additionally, Eq. (9j) and (9k) identify the peak electricity pk^{elec} and gas power pk^{gas} values, respectively.

2.2.4. Future price projections and CO_2 reduction targets

To achieve 55 % of CO_2 reduction by 2030 and full elimination by 2050 as the EU envisions (European Commission, 2019), carbon allowance prices must close the cost gap between gas and electricity. To assess which carbon prices can effectively provide this incentive, we rely on electricity and gas price forecasts for 2030 and 2050, using scenarios developed by the European Network of Transmission System Operators for Electricity (ENTSOE) (see Section 2.1.1), as these prices will strongly influence the results. We also assume that, in response to European decarbonization policies, the company will be required to install an electric boiler by 2030. Without this addition, the only alternative to decrease CO_2 emissions would be to reduce production, a measure the company is unwilling to take. The existing gas boiler is expected to remain in operation until the end of its typical service life, which ranges between 25 and 30 years for industrial boilers (Chau et al., 2009; Byworth Boilers, 2022). Consequently, we operate under the assumption that by 2030, companies will have operational flexibility to produce steam, where boiler usage is optimally scheduled based on electricity and gas price dynamics (see Eq. (9)).

In the previous Section 2.2.3, we explicitly included the historical CO_2 prices in the calculations, running the model twice: once with the carbon prices and once without, to assess their impact on CO_2 emissions. This approach works well when carbon prices are already known. However, for future scenarios, we will change the adopted strategy. In this scenario, we will set a target for a specific reduction in CO_2 emissions (denoted by α) and then evaluate the extra energy cost for the company to achieve this emission reduction. Essentially, we reverse the process, starting with the emissions constraint and determining the necessary carbon price to meet the target. Since we are in a partial electrification scenario, we will solve the optimization model (9a)–(9k) again, but without Eq. (9d), as we will not add the carbon prices explicitly in the model. Instead, we will add a new constraint (see Eq. (10)) to limit the amount of CO_2 emissions based on a predefined parameter α (in % value), where $g^*_{CO_2}$ is the original yearly CO_2 emissions of the company.

$$\sum_{t \in \mathcal{T}} g_t \cdot k_3 \le g^*_{CO_2} \cdot (1 - \alpha) \tag{10}$$

By identifying the energy cost increase associated with $\alpha \cdot g^*_{CO_2}$ tonnes of CO_2 reduction, we can calculate the required carbon allowance price (in €/t CO_2) to incentive this specific emission reduction.

2.2.5. Demand-side flexibility and balancing markets

By partially electrifying steam production through the use of both electric and gas boilers, the industry gains operational flexibility. Such flexibility can be leveraged by strategically responding to day-ahead spot prices, as well as participating in balancing markets. The industry can change the output of the electric boiler to respond to frequency deviations in the power grid, while keeping the production output untouched by using the gas boiler to compensate for the energy difference. When reducing the load of the electric boiler, the industry offers an upward flexibility action. Conversely, when increasing the load of the electric boiler, the industry offers a downward flexibility action. Note that directions are established from the generation perspective and thus, the logic is reversed.

Algorithm 1 mFRR and aFRR participation.

Input: $a_1, a_2, a_3, a_4, b_1, b_2, b_3, b_4, \overline{E}, \overline{G}, \eta_e, \eta_g, \overline{\delta}, \underline{\delta}, \lambda_t^{elec}, \lambda_t^{gas}, l_t^{elec}, s_t, \forall t \in T$,
$\beta^{C+}, \beta^{C-}, \lambda_d^{imb}, m_{y,d}^{C+}, m_{y,d}^{C+}, m_{z,m,y,d}^{E+}, m_{z,m,y,d}^{E-}, \forall m, z, y, d \in Z, M, Y, D$
Solve Eqs. (9) and get $e_t, g_t, pk^{gas}, pk^{elec}$.
Reshape e_t and g_t into $e_{z,m,y,d}$ and $g_{z,m,y,d}$.
Solve Eq. (A.1a) and (A.1b) and get $\overline{C}_{y,d}$, $\underline{C}_{y,d}$, $\overline{C}_{z,m,y,d}$, and $\underline{C}_{z,m,y,d}$.
Solve Eqs. (A.2a)–(A.3b) and get β_d^{E+}, β^{E-}.
for $d = 1$ to D **do**
  for $y = 1$ to Y **do**
    if $\overline{C}_{y,d} > \underline{C}_{y,d} \wedge \overline{C}_{y,d} > 0$ **then** ▷ Go to positive market (load decrease)
      if $\beta^{C+} < m_{y,d}^{C+}$ **then**
        $\mathcal{R}_{y,d}^{C} = \overline{C}_{y,d} \cdot \beta^{C+}$
      end if
      for $m = 1$ to M **do**
        for $z = 1$ to Z **do**
          if $\beta_d^{E-} < m_{z,m,y,d}^{E+}$ **then**
            $\mathcal{R}_{z,m,y,d}^{E} = \overline{C}_{z,m,y,d} \cdot (m_{z,m,y,d}^{E+} - \beta_d^{E-})$
            $e_{z,m,y,d}^{new} = e_{z,m,y,d} - \overline{C}_{z,m,y,d}$
            $g_{z,m,y,d}^{new} = g_{z,m,y,d} + \overline{C}_{z,m,y,d} \cdot \frac{\eta_{elec}}{\eta_{gas}}$
          end if
        end for
      end for
    end if
    if $\underline{C}_{y,d} \geq \overline{C}_{y,d} \wedge \underline{C}_{y,d} > 0$ **then** ▷ Go to negative market (load increase)
      if $\beta^{C-} < m_{y,d}^{C-}$ **then**
        $\mathcal{R}_{y,d}^{C} = \underline{C}_{y,d} \cdot \beta^{C-}$
      end if
      for $m = 1$ to M **do**
        for $z = 1$ to Z **do**
          if $\beta^{E-} < m_{z,m,y,d}^{E-}$ **then**
            $e_{z,m,y,d}^{new} = e_{z,m,y,d} + \underline{C}_{z,m,y,d}$
            $g_{z,m,y,d}^{new} = g_{z,m,y,d} - \underline{C}_{z,m,y,d} \cdot \frac{\eta_{elec}}{\eta_{gas}}$
            if $d \neq 365$ **then**
              $\mathcal{R}_{z,m,y,d}^{E} = \underline{C}_{z,m,y,d} \cdot (m_{z,m,y,d}^{E-} + \lambda_{d+1}^{gas} - \beta^{E-})$
            else
              $\mathcal{R}_{z,m,y,d}^{E} = \underline{C}_{z,m,y,d} \cdot (m_{z,m,y,d}^{E-} + \lambda_{d}^{gas} - \beta^{E-})$
            end if
          end if
        end for
      end for
    end if
  end for
end for
Output: $\mathcal{R}_{y,d}^{C}, \mathcal{R}_{z,m,y,d}^{E}, e_{z,m,y,d}^{new}$, and $g_{z,m,y,d}^{new}$.

Algorithm 1 outlines the simulation of participating in balancing markets. We can use the same procedure for both the mFRR and aFRR balancing markets, as they both follow the same market rules. The only distinction between the two markets lies in the required activation period for flexibility: 15 minutes for the mFRR market and 5 minutes for the aFRR market (Consentec GmbH, 2022). As a result, the available flexibility considered for the aFRR market is set to one-third of that used in the mFRR market. Furthermore, the marginal prices must be updated to reflect the respective market under analysis.

The algorithm starts by calculating the boiler's production schedule based on day-ahead spot prices, as seen in Section 2.2.3. Then, based on those schedules, it calculates the maximum flexibility companies can offer within the positive market ($\overline{C}_{y,d}$ for the capacity and $\overline{C}_{z,m,y,d}$ for the energy market) using Eq. (A.1a) and within the negative market ($\underline{C}_{y,d}$ for the capacity and $\underline{C}_{z,m,y,d}$ for the energy market) using Eq. (A.1b). We assume that we will participate in the market, either positive or negative, where we have the highest flexibility to offer. When having the same amount of flexibility to offer in both directions, we will prioritize the negative market, to enhance the use of electricity. Moreover, the market will only accept the offered flexibility if the bid is below or equal to the marginal price (Consentec GmbH, 2022). We have conducted a sensitivity analysis for the capacity market bids (see A.4 and A.5) and selected the optimal bid of the year (β^{C+} for the positive and β^{C-} for the negative market). Notice that the capacity market operates under a pay-as-bid basis (Consentec GmbH, 2022), and thus, we will get the price specified in our bid, if selected ($\beta^{C+} \leq m_{y,d}^{C+}$ and $\beta^{C-} \leq m_{y,d}^{C-}$). Conversely, for the energy market bids, we have calculated the cost of activating the flexibility (β_d^{E+} for positive and β^{E-} for negative market) using Eqs. (A.2) and (A.3). The energy market operates under a pay-as-cleared basis (Consentec GmbH, 2022). Therefore, if selected ($\beta_d^{E+} \leq m_{m,z,y,d}^{E+}$ and $\beta^{E-} \leq m_{m,z,y,d}^{E-}$), we will get the marginal price as revenue. Finally, Eqs. (A.4) and (A.5) calculate the final loads of the boilers since activating the flexibility changes the original scheduled loads of the boilers, as well as CO_2 emissions.

3. Results

This section presents the calculated energy costs and carbon emissions across various scenarios and years, based on the historical consumption profiles of two plastic manufacturing companies. First, we examine the impact of historical carbon allowance prices on companies' energy costs and CO_2 emissions. Next, we estimate the average carbon allowance price required to achieve a 55 % reduction in CO_2 emissions by 2030 and full decarbonization by 2050. Finally, we assess the potential economic benefits these companies could gain by leveraging demand-side flexibility through the operation of two boilers and participation in balancing markets.

3.1. Impact of historical carbon allowance prices (RQ1)

In the current operational setup, both companies rely on a gas boiler to generate the steam required for their manufacturing processes. As a result, these companies emit CO_2 emissions while operating the boiler. We have calculated that the first company emits 39.872 tonnes of CO_2 yearly and the second company emits 53.407 tonnes. If the company does not purchase an electric boiler and is not willing to reduce the production output, the EU–ETS will increase its energy costs. Tables 3 and 4 offer the resultant historical energy cost of using the gas boiler when accounting for carbon allowance prices and without, as well as the costs associated with operating an electric boiler (instead of the gas boiler) between 2019 and 2024.

Table 3
Historical energy costs for Company 1.

	Gas boiler		Electric boiler
	No EU–ETS	With EU–ETS	
2019	14.89 M€	15.87 M€	23.73 M€
2020	12.82 M€	13.80 M€	20.98 M€
2021	29.63 M€	31.71 M€	43.49 M€
2022	66.35 M€	69.56 M€	93.15 M€
2023	29.33 M€	32.66 M€	44.72 M€
2024	25.02 M€	27.61 M€	38.02 M€

*M€: million euros.

Table 4
Historical energy costs for Company 2.

	Gas boiler		Electric boiler
	No EU–ETS	With EU–ETS	
2019	12.33 M€	13.65 M€	24.69 M€
2020	10.46 M€	11.78 M€	21.95 M€
2021	25.94 M€	28.73 M€	45.06 M€
2022	57.94 M€	62.23 M€	93.35 M€
2023	24.91 M€	29.38 M€	45.54 M€
2024	21.43 M€	24.90 M€	39.21 M€

*M€: million euros.

Results indicate that energy costs exhibited significant fluctuations, with sharp increases in 2021 and 2022 due to geopolitical factors, followed by a decline in 2023 and 2024. But more importantly, our findings show that historical carbon allowance prices led to an increase in energy costs ranging from 4.8 % to 11.4 % for the first company and 7.4 % to 17.9 % for the second company. Nevertheless, historical carbon allowance prices have not been sufficient to drive full electrification in these industries, as steam production with an electric boiler remained significantly more expensive. On average, the first company would have incurred 52.5 % higher costs for steam production using electricity, while the second company would have faced an 85.1 % increase. However, when accounting for carbon allowance prices, these cost differences decrease to 41.2 % and 64.5 %, respectively.

On the other hand, pushed by increasing carbon allowance prices, industries can partially electrify their steam consumption by purchasing an electric boiler while still keeping the gas boiler. When having two boilers available, industries would strategically schedule the boilers based on the spot gas and electricity prices to reduce the total energy cost of the company. Tables 5 and 6 display the resultant energy costs and CO_2 emissions industries would emit when accounting for carbon allowance prices, and without.

Table 5
Energy costs and CO_2 emissions from partial electrification (Company 1).

	No EU–ETS		With EU–ETS	
	Energy cost	CO_2	Energy cost	CO_2
2019	14.82 M€	39.79 kt	15.80 M€	39.73 kt
2020	12.75 M€	39.81 kt	13.73 M€	39.75 kt
2021	29.54 M€	39.60 kt	31.60 M€	39.47 kt
2022	66.08 M€	37.03 kt	69.01 M€	35.89 kt
2023	29.21 M€	39.23 kt	32.49 M€	38.93 kt
2024	24.91 M€	39.28 kt	27.45 M€	37.78 kt

*M€: million euros, kt: thousand of tonnes.

Table 6
Energy cost and CO_2 emissions from partial electrification (Company 2).

	No EU–ETS		With EU–ETS	
	Energy cost	CO_2	Energy cost	CO_2
2019	12.33 M€	53.38 kt	13.64 M€	53.35 kt
2020	10.45 M€	53.39 kt	11.77 M€	53.35 kt
2021	25.92 M€	53.27 kt	28.70 M€	53.19 kt
2022	57.56 M€	49.31 kt	61.46 M€	47.76 kt
2023	24.86 M€	53.03 kt	29.12 M€	49.37 kt
2024	21.39 M€	52.99 kt	24.69 M€	48.94 kt

*M€: million euros, kt: thousand of tonnes.

Results indicate that when having both the electric and gas boilers available, the CO_2 emissions reduce between 65 and 2.842 tonnes for the first company (representing 0.16 % and 7.13 % of reduction compared to original emissions) and between 18 and 4.102 tonnes for the second company (representing 0.03 % and 7.68 % of reduction). These reductions are influenced by how often spot electricity prices are lower than gas prices, but not entirely. From the historical spot prices shown in Fig. 1, we can observe that electricity was cheaper than gas more frequently (between 5.7 % and 17.9 %). This might suggest that more CO_2 reductions should have occurred. However, when network capacity tariffs are included in the calculations, the optimization model does not produce all the steam with the electric boiler, even when electricity is cheaper. Part of the steam is still produced with the gas boiler to avoid increasing the original peak electric power of the company and incurring higher network capacity costs.

Additionally, when we add carbon allowance prices to the calculations, electricity becomes cheaper than gas more often since the utilization of the gas will now have an additional cost. Therefore, carbon allowance prices can encourage industries to further use the electric boilers and thus, eliminate more CO_2 emissions. Our results show that, historical carbon allowance prices could have further incentivized between 63 and 1.506 more CO_2 tonnes for the first company and between 34 and 4.053 tonnes for the second company. Consequently, we can argue that carbon allowance prices alone incentivized between 0.2 % and 4.0 % of CO_2 reduction for the first company and between 0.1 % and 8.3 % for the second company.

3.2. Required carbon allowance prices for 2030 and 2050 targets (RQ2)

The EU has set a goal of reducing 55 % of CO_2 emissions by 2030 and has implemented the EU–ETS to support this objective. By controlling the overall carbon allowances, the EU is deliverably influencing the market to increase carbon allowance prices. Considering the projected EU allowances, carbon prices are forecasted to reach 150 €/t CO_2 by 2030 (BloombergNEF, 2024; Pahle et al., 2022). In this subsection, we aim to analyze if this forecasted price will be enough to encourage industries to reduce 55 % of their CO_2 emissions.

Assuming that industries purchase an electric boiler by 2030, and based on the projected electricity and gas spot prices for 2030 (see Fig. 2), we calculated the cost increase both companies incur when restricting allowable CO_2 emissions. For that purpose, we have solved Eqs. (9a–9k \ (9d)) with the additional constraint (10). By dividing the energy cost increase with the reduced tonnes of CO_2 emissions, we can determine the cost per tonne of CO_2 reduction. The resulting prices are presented in Table 7 for different levels of CO_2 reduction (α).

Table 7
Economic impact of CO_2 reduction in 2030.

	Company 1		Company 2	
α	EC increase	CO_2 price	EC increase	CO_2 price
10 %	0.46 M€	115.7 €/t CO_2	0.59 M€	109,7 €/t CO_2
20 %	0.96 M€	120.3 €/t CO_2	1.27 M€	119,2 €/t CO_2
30 %	1.71 M€	142.8 €/t CO_2	2.29 M€	142,8 €/t CO_2
35 %	2.11 M€	151.5 €/t CO_2	2.84 M€	151,7 €/t CO_2
40 %	2.56 M€	160.4 €/t CO_2	3.44 M€	160,8 €/t CO_2
50 %	3.71 M€	186.0 €/t CO_2	4.96 M€	185,7 €/t CO_2
55 %	4.43 M€	202.1 €/t CO_2	5.90 M€	201,0 €/t CO_2

M€: million euros, EC: Energy cost, α: CO_2 reduction level.

From the results displayed in Table 7, it is evident that carbon allowance prices alone will not provide sufficient incentive for industries to achieve the targeted 55 % CO_2 reduction. According to our findings, Company 1 would achieve a CO_2 reduction of 34.2 %, while Company 2 would reach 34.0 % (given that carbon allowance prices are 150 €/t CO_2 in 2030). To meet the 55 % reduction target, Company 1 would require an average carbon allowance price of 202.1 €/t CO_2, while Company 2 would need 201.0 €/t CO_2.

On the other hand, to determine the required average carbon allowance price to incentivize industries to fully electrify their steam production by 2050, we have used the forecasted electricity and gas price scenarios reported by ENTSOE (see Section 2.1.1). Considering the cost increase alongside the CO_2 emissions saved, we again determined the cost per tonne of CO_2 reduction. The results are presented in Table 8. Our calculations indicate that, on average, industries would require a carbon allowance price of 237.2 €/t CO_2 to incentivize full electrification. In the most favorable scenario, a price of 197.1 €/t CO_2 would be sufficient. However, in the most challenging scenario, a carbon allowance price of 293.4 €/t CO_2 would be necessary to drive industries toward fully electrifying their steam production.

3.3. Demand-side flexibility and impact on CO_2 emissions (RQ3)

Although carbon allowance prices increase the overall cost of gas and reduce the price difference between gas and electricity, companies will face higher energy costs, regardless of whether they use gas or electricity. This increase in energy expenses puts their business models at risk. To mitigate this challenge, companies can leverage the flexibility gained from purchasing an electric boiler, by participating in balancing services. In this subsection, we analyze the historical revenues industries

Table 8
Economic impact (in million euros) of CO_2 reduction in 2050.

	Company 1		Company 2	
Scenario	EC increase	CO_2 price	EC increase	CO_2 price
CY95_DE	9.05 M€	227.1 €/t CO_2	12.93 M€	242.1 €/t CO_2
CY95_GA	7.86 M€	197.1 €/t CO_2	11.14 M€	208.6 €/t CO_2
CY08_DE	9.25 M€	232.0 €/t CO_2	12.80 M€	239.6 €/t CO_2
CY08_GA	7.90 M€	198.2 €/t CO_2	11.01 M€	206.2 €/t CO_2
CY09_DE	11.38 M€	285.5 €/t CO_2	15.67 M€	293.4 €/t CO_2
CY09_GA	9.91 M€	248.4 €/t CO_2	14.31 M€	268.0 €/t CO_2
Average	**92.3 M€**	**231.4 €/t CO_2**	**12.98 M€**	**243.0 €/t CO_2**

*CY: Climate year, EC: Energy cost, DE: Distributed Energy, GA: Global Ambition.

could have earned by offering flexibility to the mFRR and aFRR markets. We determine which of these markets is more profitable and explore the impact of flexibility provision on the overall CO_2 emissions.

3.3.1. Day-ahead and mFRR markets

When both gas and electric boilers are available, the company gains operational flexibility. This flexibility allows for optimizing the boilers' schedule based on electricity and gas spot prices, while also enabling participation in the mFRR balancing capacity and energy markets. For the mFRR energy market, we determined the company's marginal costs for activating the flexibility (see Eq. (A.2)–(A.3)), and we used these values as bids for the energy market. However, for the capacity market, the price for maintaining reserves cannot be directly calculated. Anyhow, since revenue depends on the submitted bid to the mFRR capacity market, A.4 offers a sensitivity analysis to identify the optimal yearly bid. Based on the optimal calculated capacity bids (β^{C+} and β^{C-}), Tables 9 and 10 present the revenues from participating in the mFRR market, the resulting energy costs, and the CO_2 emissions.

Table 9
Day-ahead and mFRR participation results (Company 1).

	No EU–ETS			With EU–ETS		
	$\mathcal{R}_{mFRR}$	EC_f	CO_2	$\mathcal{R}_{mFRR}$	EC_f	CO_2
2020	37.17 k€	12.71 M€	39.83 kt	46.82 k€	13.68 M€	39.75 kt
2021	21.53 k€	29.51 M€	39.60 kt	21.54 k€	31.58 M€	39.46 kt
2022	255.40 k€	65.82 M€	36.98 kt	255.86 k€	68.75 M€	35.84 kt
2023	529.52 k€	2868 M€	39.10 kt	530.74 k€	31.96 M€	38.81 kt
2024	328.22 k€	2458 M€	39.15 kt	130.34 k€	27.32 M€	37.66 kt

*M€: million euros, k€: thousand euros, $\mathcal{R}$: Revenue, EC: Energy cost, f: final.

Table 10
Day-ahead and mFRR participation results (Company 2).

	No EU–ETS			With EU–ETS		
	$\mathcal{R}_{mFRR}$	EC_f	CO_2	$\mathcal{R}_{mFRR}$	EC_f	CO_2
2020	20.69 k€	10.43 M€	53.41 kt	20.10 k€	11.75 M€	53.35 kt
2021	9.47 k€	25.91 M€	53.27 kt	9.12 k€	28.69 M€	53.18 kt
2022	388.83 k€	57.17 M€	49.23 kt	390.56 k€	61.07 M€	47.68 kt
2023	410.91 k€	24.45 M€	52.94 kt	1.16 M€	27.96 M€	49.17 kt
2024	209.16 k€	21.18 M€	52.90 kt	227.77 k€	24.46 M€	48.74 kt

*M€: million euros, k€: thousand euros, $\mathcal{R}$: Revenue, EC: Energy cost, f: final.

Our results indicate that by offering flexibility to the mFRR market, the first company can achieve energy cost savings of up to 2.2 % in 2023, with an average reduction of 1.2 % across all years, while the second company can save up to 2.7 % in 2023, with an average reduction of 2.0 %. However, when incorporating carbon allowance prices, the additional revenues generated from market participation are insufficient to offset the increased costs. Consequently, the first company still faces an average cost increase of 7.0 %, while the second company experiences a rise of 9.8 %.

On the other hand, the revenues generated from participating in the mFRR market exhibit variability with the inclusion of carbon allowance prices, fluctuating randomly between increases and decreases. When carbon allowance prices are excluded, gas spot prices tend to be lower than electricity more frequently. Consequently, the optimal operation of the boilers favors the use of the gas boiler over the electric one, increasing the company's available load increase flexibility, which enables participation in the downward balancing market. However, when carbon allowance prices are factored in, electricity spot prices become more competitive relative to gas. As a result, the optimization model selects the electric boiler more frequently, shifting the company's available flexibility from load increase to load decrease, thereby facilitating participation in the upward balancing market. The net impact on revenues depends on the relative marginal prices of these markets: if the marginal prices in the upward market exceed those in the downward market, the company benefits from higher revenues within the EU–ETS scenario. Conversely, if downward market prices are higher, revenues decline compared to the scenario without carbon allowance prices.

3.3.2. Day-ahead and aFRR market

Companies can also offer their flexibility to the aFRR balancing market instead of the mFRR market using the same strategy. However, in the aFRR market, full activation of flexibility must occur within 5 minutes, compared to 15 minutes in the mFRR market (Consentec GmbH, 2022). Consequently, the maximum capacity and energy available for the aFRR market will be limited to one-third of what can be offered in the mFRR market. Meanwhile, bids submitted to the energy market will continue to be based on the calculated marginal prices for flexibility activation (see Eqs. (A.2)–(A.3)), while a sensitivity analysis will be conducted to determine the optimal bid for the capacity market (see A.5). Tables 11 and 12 present the generated revenues from aFRR participation, the final energy costs, and CO_2 emissions for both companies.

Table 11
Day-ahead and aFRR participation results (Company 1).

	No EU–ETS			With EU–ETS		
	$\mathcal{R}_{aFRR}$	EC_f	CO_2	$\mathcal{R}_{aFRR}$	EC_f	CO_2
2020	127.94 k€	12.62 M€	39.82 kt	127.34 k€	13.60 M€	39.75 kt
2021	76.70 k€	29.46 M€	39.57 kt	82.33 k€	31.52 M€	39.44 kt
2022	962.11 k€	65.11 M€	37.04 kt	1.05 M€	67.96 M€	35.94 kt
2023	1.48 M€	27.73 M€	37.75 kt	1.79 M€	30.70 M€	37.10 kt
2024	1.18 M€	23.73 M€	37.18 kt	1.14 M€	26.31 M€	36.76 kt

*M€: million euros, k€: thousand euros, $\mathcal{R}$: Revenue, EC: Energy cost, f: final.

Table 12
Day-ahead and aFRR participation results (Company 2).

	No EU–ETS			With EU–ETS		
	$\mathcal{R}_{aFRR}$	EC_f	CO_2	$\mathcal{R}_{aFRR}$	EC_f	CO_2
2020	93.99 k€	10.36 M€	53.40 kt	96.41 k€	11.67 M€	53.35 kt
2021	53.06 k€	25.86 M€	53.25 kt	55.26 k€	28.64 M€	53.16 kt
2022	0.99 M€	56.57 M€	49.35 kt	1.07 M€	60.40 M€	47.86 kt
2023	1.46 M€	23.40 M€	51.52 kt	1.43 M€	27.69 M€	48.32 kt
2024	1.12 M€	20.27 M€	51.07 kt	1.21 M€	23.48 M€	47.81 kt

*M€: million euros, k€: thousand euros, $\mathcal{R}$: Revenue, EC: Energy cost, f: final.

The first notable observation is that participation in the aFRR market yields higher revenues than the mFRR market, despite having more restrictive market requirements and being able to offer less flexibility. The first company could have achieved energy cost savings of up to 5.4 % in 2023, with an average reduction of 2.9 %, while the second company could have saved up to 6.9 % in 2023, with an average reduction of 4.0 %. However, these savings remain insufficient to fully offset the increased costs associated with EU–ETS. As a result, the first company would still face an average of 5.0 % increase in energy costs, while the second company would experience an 8.2 % rise, compared to their current energy costs.

Furthermore, participation in balancing energy markets can negatively influence the overall CO_2 emissions. When the cumulative flexibility offered to the positive market exceeds that of the negative market, the company relies more on gas, leading to higher CO_2 emissions. Without carbon allowance prices, the company would primarily use the gas boiler for steam production. In this scenario, it can offer a load increase as flexibility and participate in the negative market. If activated, the company would switch from the gas boiler to the electric one, ultimately reducing emissions. However, as carbon allowance prices rise, this pattern reverses. Companies initially prioritize the electric boiler, making a load decrease as the available flexibility (positive market). If selected for activation, they would revert to using the gas boiler, increasing CO_2 emissions. Consequently, if companies offer flexibility to balancing markets as a new business model to mitigate the cost increases they are facing, they may still end up emitting significant amounts of CO_2.

4. Discussion

The EU's strategy to achieve its climate targets relies on the progressive tightening of carbon allowances under the EU–ETS. This policy mechanism is intended to create economic incentives for industries to transition towards electricity by making fossil fuel consumption progressively more expensive.

4.1. Impact of historical carbon prices on energy costs and emissions

Our findings indicate that between 2019 and 2024, historical carbon allowance prices have contributed to narrowing the energy cost gap between gas and electricity by 11.3 % and 20.6 %, respectively, for the two plastic manufacturing companies analyzed. While this reduction suggests that the EU–ETS has had an impact on energy cost structures, it has not yet been sufficient to fully incentivize electrification, as gas-fired steam production has remained more cost-competitive despite rising CO_2 prices. In addition to cost impacts, our results show that historical carbon allowance prices have led to CO_2 emission reductions of up to 4.0 % and 8.3 %, highlighting that while the system has driven some decarbonization, these reductions remain considerably below the levels required to meet the EU's climate objectives.

To mitigate the energy cost increase caused by the EU–ETS, companies can participate in balancing markets by offering flexibility. Our results indicate that although the offered capacity is lower in the aFRR market, the generated revenues are higher than in the mFRR market due to the greater activity it presents. Nevertheless, these savings are insufficient to fully offset the higher costs brought on by the EU–ETS. Even with aFRR revenues, companies would still have to pay 6.6 % more for their energy utilization on average. Furthermore, accounting for the increased operation and maintenance (O&M) costs of operating two boilers simultaneously can further reduce the cost savings potential of the companies. Finally, while participating in balancing markets can help companies cope financially, it can have unintended environmental consequences. Depending on market conditions, offering flexibility could lead to higher CO_2 emissions.

4.2. Future carbon price thresholds for industrial decarbonization

Based on projected gas and electricity prices from the ENTSOE scenarios, our analysis suggests that the forecasted 150 €/t CO_2 price will not be enough to achieve a 55 % of CO_2 reduction within the plastic manufacturing sector by 2030. Instead, we estimate a reduction of only 34 % (see Table 7). This finding suggests that under current policy settings, the EU–ETS alone will not be sufficient to drive the required pace of industrial decarbonization. To meet the 55 % CO_2 emission reduction target by 2030, our results indicate that the carbon price would need to reach at least 201.5 €/tonne CO_2 on average. Furthermore, achieving full electrification of industrial steam production by 2050 would require an even higher carbon price, averaging 237.2 €/t CO_2 across the studied scenarios (see Table 8). In the most favorable scenario, a price of 197.1 €/t CO_2 would be sufficient, while in the most challenging conditions, the required price could rise to 293.4 €/t CO_2 to effectively incentivize complete electrification within the studied plastic manufacturing companies.

4.3. Generalizability and limitations of the study

Although this study is based on consumption data from two Luxembourgish plastic manufacturing companies, they rank among the largest in the country and produce different plastic products using different processes. This diversity, along with their shared dependence on steam generated from gas boilers, supports the view that the findings are broadly representative of the national plastic manufacturing sector. Moreover, industries beyond the plastic sector (such as chemicals (Khrushch et al., 1999), pulp and paper (Khrushch et al., 1999; Hubbe, 2021), and textile (Hasanbeigi and Zuberi, 2022)) also depend heavily on steam in continuous operations. These sectors may face similar challenges and opportunities when electrifying their systems, making our methodology and results potentially relevant beyond the plastic sector.

Yet, the economic impact of electrification is not uniform across all facilities. The key determinant is the proportion of the total energy demand attributed to steam production, which can vary between sites. In our analysis, the second company exhibited a higher reliance on steam, leading to greater energy cost impacts when fully transitioning to electricity (see Tables 3 and 4) and requiring a higher carbon price to make electrification economically viable (see Table 8). In addition, part of our analysis relies on projections of electricity and gas prices, which are inherently uncertain. We employed ENTSO-E scenario data (ENTSO-E/ENTSO-G, 2024) for the years 2030 and 2050, as these forecasts are developed with considerable rigor and aim to capture a broad range of plausible future developments. However, despite this robust methodology, the actual evolution of energy markets remains unknown due to potential shifts in geopolitical conditions, technological advancements, meteorological conditions, and evolving policy landscapes. As time progresses and actual market prices are revealed, more precise and context-specific evaluations of the economic viability of electrification will become feasible.

Geographic location is another critical factor, as it influences the exposure to electricity and gas prices. Our modeling uses spot and balancing prices for Luxembourg, reflecting the actual location of the two companies studied. However, for other locations, the analysis should be replicated using region-specific prices to ensure contextual accuracy (available through EEX (2024b); ENTSOE (2024); EEX (2024a) for historical prices and via ENTSO-E/ENTSO-G (2024) for forecasted ENTSO-E scenarios). This offers a practical tool for evaluating electrification strategies, assessing the decarbonization potential, and supporting policy development in various industrial contexts.

4.4. Policy recommendations

To achieve meaningful industrial decarbonization without compromising competitiveness, coordinated action between policymakers and industry stakeholders is essential. Drawing on insights from our analysis, the following recommendations present concrete, actionable steps to support the transition toward low-carbon operations in the plastic manufacturing sector. These proposals aim to balance environmental goals with economic resilience and long-term industrial viability.

1. *Strengthen Carbon Pricing Mechanisms (Policymakers)*: To meet EU carbon reduction targets within plastic manufacturing sector, stronger carbon pricing signals are essential. Our results show that current carbon prices are insufficient to incentivize electrification. Therefore, the EU should accelerate the reduction of available

allowances in the EU ETS and move toward phasing out free allocations. As the EU directly controls the cap on allowances, it has the leverage to use its market power to increase carbon prices.

2. *Redirect EU–ETS Revenues to Support Electrification (Policymakers)*: With or without carbon pricing, electrification places a significant financial burden on plastic manufacturers. Policymakers should use revenues collected from carbon pricing to subsidize the adoption of clean technologies and offset increased energy costs during the transition period. Strategic allocation of these funds can ensure that industries decarbonize without undermining national economic resilience or competitiveness.
3. *Assist Industrial Participation in Balancing Markets (Policymakers and Industry)*: Balancing market participation offers a valuable revenue stream for electrified industrial operations, helping to offset the higher operating costs. However, many industrial firms currently lack the technical expertise or market knowledge needed to access these opportunities. To address this, governments should provide targeted support and dedicated market integration initiatives. In parallel, industries should invest in automation and process controls to enable flexibility provision in the aFRR market. Crucially, greater participation in balancing markets can reduce the level of public subsidies required, easing the financial burden on governments while supporting a self-sustaining transition to low-carbon industrial processes.
4. *Promote Load Flexibility as a Strategic Business Decision (Industry)*: In a fully electrified future (e.g., 2050), steam generation will be entirely dependent on electric boilers, eliminating fuel-switching flexibility. While many companies currently resist altering steam loads, our analysis demonstrated that load adjustment changes can generate substantial revenues. Industry stakeholders should revisit internal policies on process rigidity and assess the long-term economic benefits of strategic load flexibility to reduce dependency on public subsidies.

5. Conclusions

In this paper, we analyzed the impact of the EU carbon policy on the electrification efforts of two major European plastic manufacturing companies. While the EU-ETS has contributed to narrowing the energy cost gap between gas and electricity and driven modest CO_2 emission reductions, it has not yet been sufficient to fully incentivize industrial decarbonization. Our analysis indicates that the forecasted carbon price trajectory will likely fall short of achieving the EU's 55 % CO_2 reduction target by 2030. Additionally, we calculate that an average price of 237.2 €/t CO_2 will be necessary to achieve full decarbonization by 2050. Furthermore, while companies can reduce energy costs by participating in balancing markets, our calculations show that the revenues from offering flexibility are not enough to offset the higher energy costs induced by carbon allowance prices. Besides, such participation may inadvertently increase CO_2 emissions, especially under certain market conditions. Consequently, to achieve deeper decarbonization, more aggressive carbon pricing and comprehensive strategies for industrial electrification will be necessary.

CRediT authorship contribution statement

Estibalitz Ruiz Irusta: Writing – review & editing, Writing – original draft, Visualization, Validation, Methodology, Investigation, Formal analysis, Conceptualization. **Ivan Pavić:** Writing – review & editing, Supervision, Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Appendix

This appendix provides a detailed explanation of the simulation methodology used for analyzing participation in the balancing markets (mFRR and aFRR). It begins with an overview of the historical marginal prices used as input data, then outlines the steps for calculating the company's available flexibility, bid submissions, and revenue estimation. The appendix concludes with a sensitivity analysis to determine the optimal annual capacity bid.

A.1. mFRR historical marginal prices

The mFRR consists of two markets: the capacity market, which secures a predefined amount of power in advance for grid operator use, and the energy market, where selected reserve providers submit bids per MWh for potential activation (Amprion GmbH et al., 2022). While the capacity market follows a pay-as-bid structure, the energy market operates on a pay-as-cleared basis. Additionally, the offered flexibility must be ramped up within 15 minutes (Amprion GmbH et al., 2022). Fig. A.4 presents the historical marginal prices for the mFRR capacity and energy markets from 2020 to 2024 (Regelleistung, 2025; Netztransparenz, 2025). In 2019, Germany implemented a joint clearing mechanism for the mFRR and aFRR balancing markets, integrating capacity and energy clearing (De Keyser et al., 2019). As a result, separate capacity and energy price data for 2019 were unavailable.

On average, the positive mFRR capacity market had a marginal price of 11.2 €/MW, while the negative market averaged 6.2 €/MW. Conversely, the average price of the mFRR energy market for the positive market was 846.3 €/MWh and 403.9 €/MWh for the negative market. Additionally, the data indicate that the mFRR energy market experienced minimal activity in 2020 and 2021 (between one and ten activations in total for the whole year). However, activations increased significantly between 2022 (522 activations) and 2024 (508 activations).

A.2. aFRR historical marginal prices

The aFRR market, like mFRR, is designed to maintain power system frequency within a secure range. However, a key distinction is that in the aFRR market, flexibility must be activated within 5 minutes (Consentec GmbH, 2022), demanding a faster ramping capability. Fig. A.5 shows the historical marginal prices for the aFRR capacity and energy markets from the year 2020 to 2024.

We learn that the average price between 2020 and 2024 for the aFRR capacity market was 21.0 €/MW for the positive market, and 23.0 €/MW for the negative market. On the other hand, regarding the aFRR energy market, data reveals that the average price in the positive market was 195.9 €/MWh, while in the negative market, it was −29.2 €/MWh. In the negative market, flexibility is provided either by decreasing generation or increasing consumption. As a result, negative prices are common, indicating that flexibility providers may need to pay the grid. Finally, comparing the mFRR and aFRR markets, we observe that the aFRR market experiences more frequent activations (between 588 activations in 2020 and 69.556 in 2023).

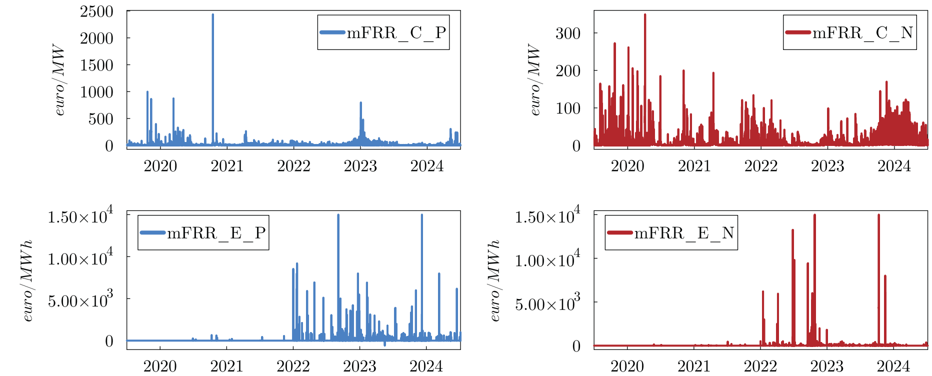


Fig. A.4. mFRR capacity marginal prices (DE/LU) (Regelleistung, 2025; Netztransparenz, 2025).
C: Capacity, E: Energy, P: Positive, N: Negative.

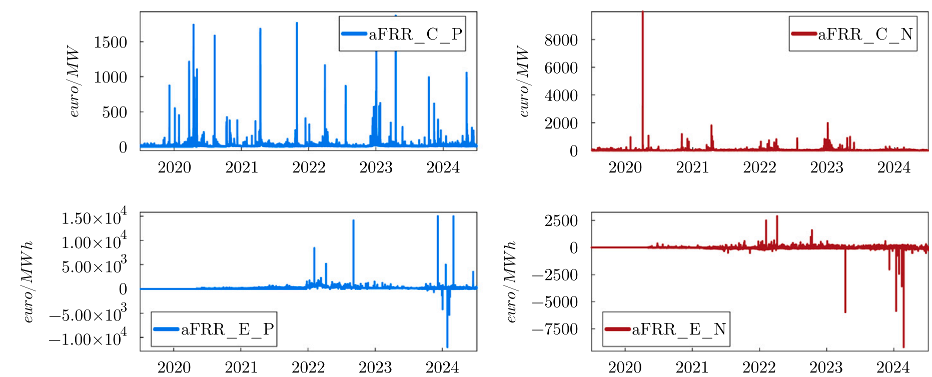


Fig. A.5. aFRR capacity marginal prices (DE/LU) (Regelleistung, 2025; Netztransparenz, 2025).
C: Capacity, E: Energy, P: Positive, N: Negative.

A.3. Participation in balancing markets

To analyze how much revenue industries can generate by offering demand-side flexibility, the first step is to determine the optimal production schedules for both gas (g_t) and electric (e_t) boilers based on the day-ahead prices, as this will be the starting point. This is achieved by solving Eqs. (9a)– (9k) as explained in Section 2.2.3. Once the production schedule of the boilers is established, the company's available flexibility can be calculated. Specifically, Eq. (A.1a) determines the maximum flexibility that is available within each hour for the positive market (load decrease, $\overline{C}_t$) and Eq. (A.1b) determines the capacity which is available for the negative market (load increase, $\underline{C}_t$).

$$\overline{C}_t = \min\{\lfloor \overline{G} - (g_t \cdot \frac{\eta_{elec}}{\eta_{gas}} \rfloor, \lfloor e_t \rfloor, \lfloor \overline{\delta} \rfloor\} \tag{A.1a}$$

$$\underline{C}_t = \min\{\lfloor \overline{E} - e_t \rfloor, \lfloor g_t \cdot \frac{\eta_{gas}}{\eta_{elec}} \rfloor, \lfloor \underline{\delta} \rfloor\} \tag{A.1b}$$

Assuming that we must respect the historical steam consumption untouched, the available flexibility for the positive market will be the minimum value between the original electric boiler's load (as we cannot reduce the load more than what is being used), the production capacity left in the gas boiler, while accounting for the efficiency difference of the boilers' (as the gas boiler must compensate for the load variation), and the ramp up capability of the gas boiler (as the gas boiler will not be able to provide more load output). Thus, Eq. (A.1a) ensures that the available flexibility takes the most restrictive value. Similarly, Eq. (A.1b) identifies the available negative flexibility as the minimum value between the original gas boiler's load (considering again boilers' efficiencies), the production capacity left in the electric boiler, and the ramp down capability of the gas boiler. Notice that the granularity of the balancing market is 1 MW (Consentec GmbH, 2022), meaning that only natural numbers are accepted (e.g., 1.5 MW of flexibility is not accepted by the market). Therefore, the calculated flexibility will be rounded down and $\overline{C}_t$ and $\underline{C}_t$ will be natural numbers to respect market rules.

Having determined the available hourly flexibility, the next step is to participate in the capacity market, which reserves flexibility in advance for a period of 4 hours (Consentec GmbH, 2022). Because this market operates with 4-hour blocks, we must calculate the minimum available capacity that we can offer within the positive, $\overline{C}_{y,d}$, and negative, $\underline{C}_{y,d}$, market from the hourly flexibilities calculated in Eqs. (A.1a) and A.1b, where $d \in \mathcal{D}$ is the set of days within a year and $y \in \mathcal{Y}$ is the set of 4-hour blocks within a day. Next, the company must submit a bid specifying the price at which they are willing to offer this flexibility within the capacity market (β^{C+} for the positive and β^{C-} for the negative market). Since we cannot calculate the marginal price of the company for having the flexibility reserved, we conduct a sensitivity analysis to identify the optimal bid of the year (see A.4 for mFRR analysis and A.5 for aFRR).

If our bid is below or equal to the marginal price ($m^{C+}_{y,d}$ and $m^{C-}_{y,d}$), it will mean that we have been selected by the balancing capacity market, and our flexibility will be reserved for potential activation. Since the capacity market operates on a pay-as-bid basis (Amprion GmbH et al., 2022), we will receive the price we offered as revenue, if selected. Additionally, we assume that we will participate in the market (either positive or negative) where we have the highest flexibility to offer. Therefore, if $\overline{C} > \underline{C}$, we participate in the positive market, and if $\underline{C} \geq \overline{C}$ we will participate in the negative market. Notice that in case of having the same amount of flexibility to offer in both directions, we will prioritize the negative market, as it will mean that we will use more electricity at the end, emitting thus less CO_2 emissions.

Whether selected or not in the capacity market, we will proceed to participate in the energy market, as allowed by the balancing market rules (Consentec GmbH, 2022). Nonetheless, because the energy market operates in 15-minute blocks, instead of 4-hour blocks as in the capacity market (Consentec GmbH, 2022), we might be able to offer more capacity than the one reserved in the capacity market. In those cases, we will proceed to submit the maximum available capacity, based on the calculated flexibilities in Eqs. (A.1a) and A.1b, to both maximize the potential revenues of the industry and offer higher flexibility options to the power grid. Variables $\overline{C}_{m,z,y,d}$ and $\underline{C}_{m,z,y,d}$ represent the available flexibility the industry possess within each 15-minute block, where $z \in \mathcal{Z}$ is the set of hours in a 4-hour block and $m \in \mathcal{M}$ is the set of 15-minute blocks within an hour. Subsequently, we will submit a bid ($\beta^{E+}_{m,z,y,d}$ and $\beta^{E-}_{m,z,y,d}$) specifying the minimum price at which the industry is ready to activate the flexibility, if necessary, for a duration of 15 minutes. We can calculate the marginal cost of activating the flexibility using Eq. (A.2a) for the positive market (load decrease) and Eq. (A.2b) for the negative market (load increase).

$$\beta^{E+}_d = (b2 + k_2 \cdot b3 + \lambda^{imb}_d) - (a2 + a3) \tag{A.2a}$$

$$\beta^{E-} = (a2 + a3) - (b2 + k_2 \cdot b3) \tag{A.2b}$$

When participating in the positive balancing market, a portion of the steam will be produced using the gas boiler instead of the electric one. As a result, gas energy utilization fees (b_2 and b_3) will apply instead of electricity fees (a_2 and a_3). Additionally, gas must be purchased at the imbalance price (λ^{imb}_d). Conversely, in the negative balancing market, steam production shifts from gas to electricity, making us subject to electricity energy fees instead of gas fees. In this case, there is no need to pay for gas imbalance, as the unused gas can be stored for future use. Furthermore, since we are providing a balancing service to the power system, we are exempt from paying electricity imbalance charges. The resulting bids are shown in Fig. A.6. Notice that while the flexibility activation of the positive market follows the daily imbalance price of the gas, the flexibility activation cost for the negative market is constant.

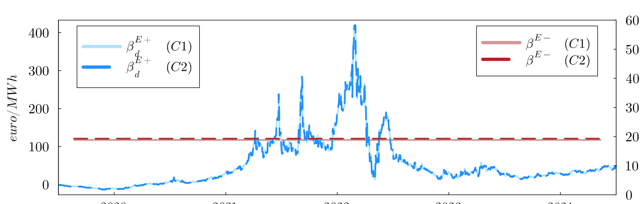


Fig. A.6. Resultant $\beta^{E+}_{m,z,y,d}$ and $\beta^{E-}_{m,z,y,d}$ bids (without EU-ETS).

Now, the flexibility activation costs calculated in Eq. (A.2) do not include the EU-ETS. If we consider carbon allowance prices within the marginal costs, we must add the additional cost of carbon emissions (λ^{co_2}) and recalculate the activation costs (see Eq. (A.3)).

$$\beta^{E+}_d = (b2 + k_2 \cdot b3 + \lambda^{imb}_d + \lambda^{co_2}) - (a2 + a3) \tag{A.3a}$$

$$\beta^{E-} = (a2 + a3) - (\lambda^{co_2} + b2 + k_2 \cdot b3) \tag{A.3b}$$

When we offer a positive flexibility, we will consume more gas, emitting thus more CO_2. On the contrary, when offering a negative flexibility, we will consume less gas and more electricity. The resulting bids are shown in Fig. A.7.

The balancing energy market operates on a pay-as-cleared basis (Consentec GmbH, 2022). Consequently, we will submit the calculated flexibility activation costs as our bids for the energy market, as any value above those costs will provide us with revenues. Similarly to the capacity market, we will get activated by the balancing energy market

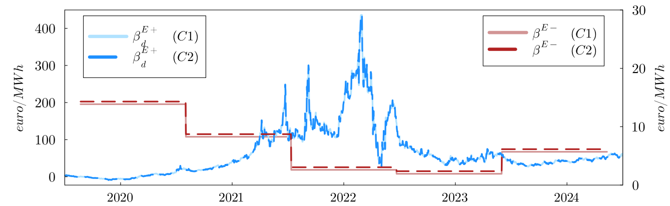


Fig. A.7. Resultant $\beta^{E+}_{m,z,y,d}$ and $\beta^{E-}_{m,z,y,d}$ bids (with EU-ETS).

if our bid is below the marginal price ($m^{E+}_{m,z,y,d}$ and $m^{E-}_{m,z,y,d}$). In addition, the obtained revenues will have to account for the calculated costs of flexibility activation. Moreover, since in this case, we actually need to deliver the flexibility, we will change the original schedules of the boilers. When participating in the positive energy market, the resultant consumption profiles can be calculated using Eq. (A.4a) for electricity and Eq. (A.4b) for gas. To offer $\overline{C}_{m,z,y,d}$ of flexibility during 15 minutes, the steam will suddenly be produced by the gas boiler, instead of the electric one. Therefore, the new electric load will have $\overline{C}_{m,z,y,d}$ less consumption. Moreover, we will have to add $\overline{C}_{m,z,y,d}$ of load to the gas boiler's original consumption, but, while accounting for the efficiency difference between the gas and electric boilers.

$$e^{new}_{z,m,y,d} = e_{z,m,y,d} - \overline{C}_{m,z,y,d} \tag{A.4a}$$

$$g^{new}_{z,m,y,d} = g_{z,m,y,d} + \overline{C}_{m,z,y,d} \cdot \frac{\eta_{elec}}{\eta_{gas}} \tag{A.4b}$$

Inversely, when participating in the negative energy market, the resultant electricity consumption will have $\underline{C}_{y,d}$ more load (see Eq. (A.5a)) and the new gas consumption will have $\underline{C}_{y,d}$ less load, but again, accounting for the difference in the boilers' efficiencies (see Eq. (A.5b)).

$$e^{new}_{z,m,y,d} = e_{z,m,y,d} + \overline{C}_{m,z,y,d} \tag{A.5a}$$

$$g^{new}_{z,m,y,d} = g_{z,m,y,d} - \overline{C}_{m,z,y,d} \cdot \frac{\eta_{elec}}{\eta_{gas}} \tag{A.5b}$$

Similarly to Section 2.2.3, we will also run the model twice, with and without accounting for carbon prices. This approach will allow us to quantify the energy cost increase incurred by the addition of EU-ETS, as well as the incentivized CO_2 emission reduction. Additionally, we will also analyze the difference between the original loads ($e_{z,m,y,d}$ and $g_{z,m,y,d}$), and the resultant loads after providing flexibility ($e^{new}_{z,m,y,d}$ and $g^{new}_{z,m,y,d}$) to see if participating in balancing markets by offering demand-side flexibility affects positively or negatively in the CO_2 emissions of the industries.

A.4. Sensitivity analysis of mFRR capacity bids

Fig. A.8 provides a sensitivity analysis of the submitted bids to the mFRR capacity market, illustrating the obtained revenues (left) and the number of accepted bids (right) across different bid levels, with and without accounting for carbon allowance prices. Results indicate that the optimal bid ranges between 4 and 32 €/MW, varying across years. In 2020, for instance, the optimal capacity bid was 32 €/MW, leading to 136 selections in the mFRR capacity market (when accounting for EU-ETS). However, in 2022 and 2023, the optimal bid was 4 €/MW, leading up to 585 selections. The higher the submitted bid, the higher the obtained revenue from each individual selection, however, the overall number of selections will decrease. On average, the optimal capacity bid was 12 €/MW. Between 2020 and 2023, the optimal bid was the same when accounting for or excluding carbon prices. However, in 2024 the carbon prices actually changed the optimal bid from 12 €/MW to 26 €/MW.

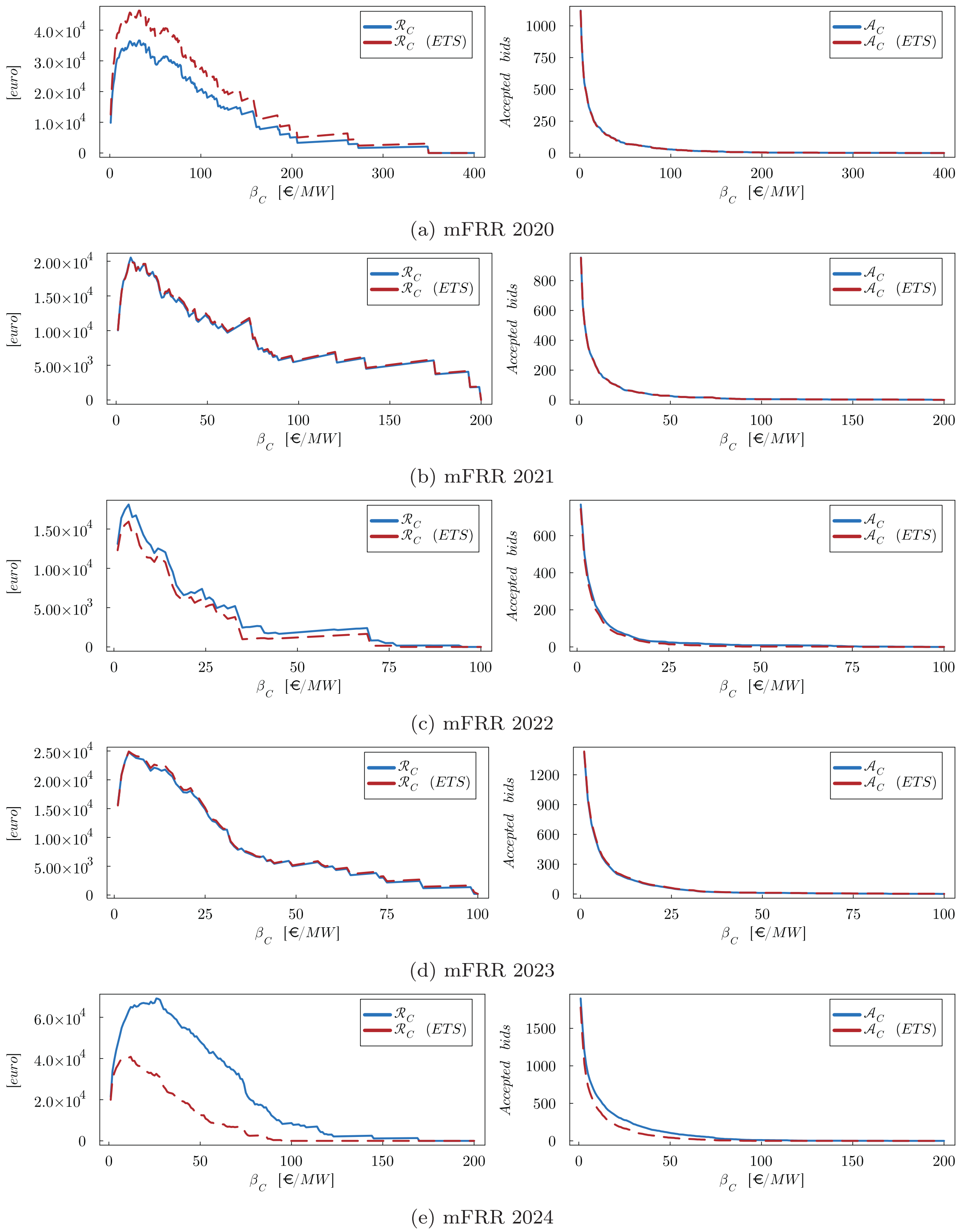
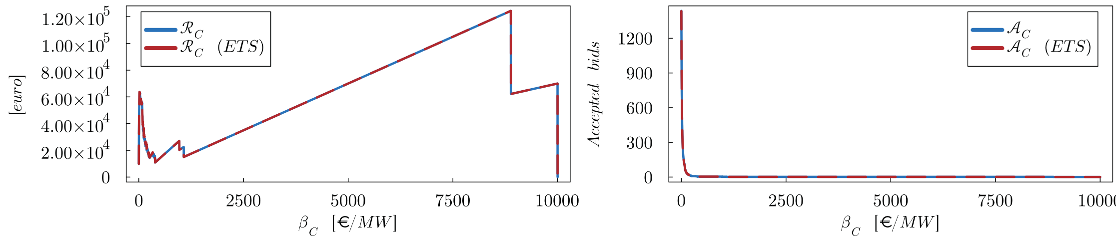


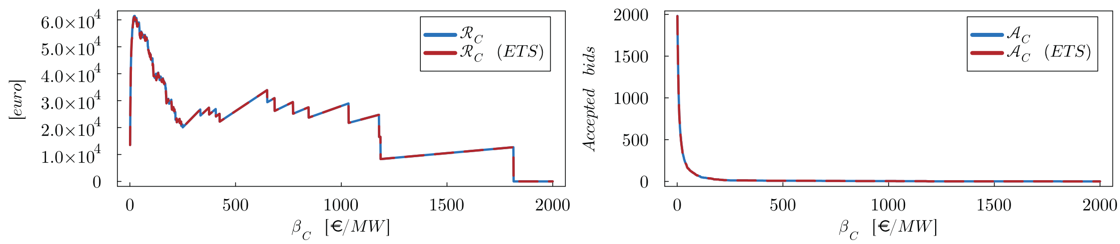
Fig. A.8. mFRR sensitivity analysis of the capacity bids (Company 1).

A.5. Sensitivitiy analysis of aFRR capacity bids

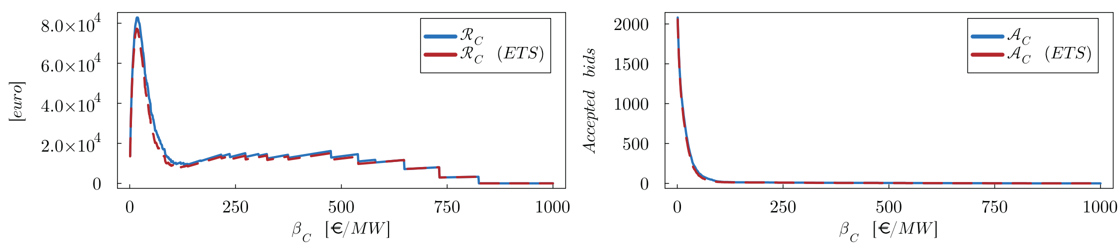
Fig. A.9 provides a sensitivity analysis for the aFRR capacity market, where the left side illustrates the potential revenues associated with the submitted bids, and the right side displays the frequency with which the bids were accepted. The optimal bid varies significantly from year to year. In 2020, the optimal bid was exceptionally high (8.883 €/MW) due to extreme aFRR capacity prices reaching the market's maximum allowable limit. Since the capacity market follows a pay-as-bid mechanism, lower bids increase the likelihood of selection but result in lower compensation per MW of reserved capacity. Conversely, higher bids reduce the frequency of selection but yield higher revenue per MW. In 2020, it was more profitable to submit a very high bid and be activated only twice rather than offering a lower price and being selected multiple times at a lower rate. Nonetheless, this was an isolated incident in 2020. Within the following years, the optimal bid ranged between 12 and 26 €/MW. During 2020, 2022, and 2023, the optimal bid was the same when accounting for EU-ETS or excluding them (8883, 17, and 26 €/MW respectively). However, in 2021 and 2024, carbon prices changed the optimal bid from 21 to 23 €/MW and from 12 to 14 €/MW, respectively.



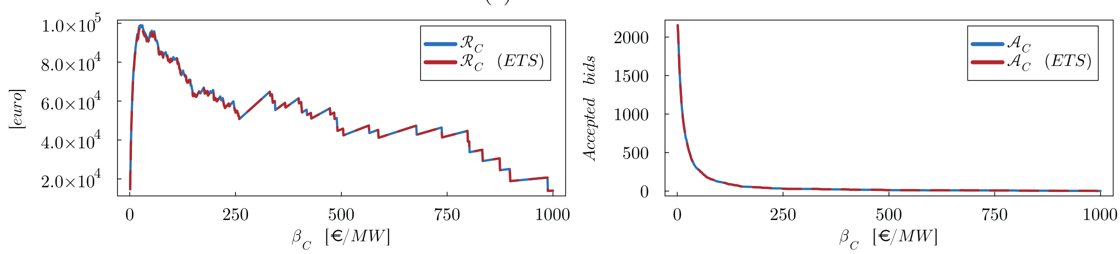
(a) aFRR 2020



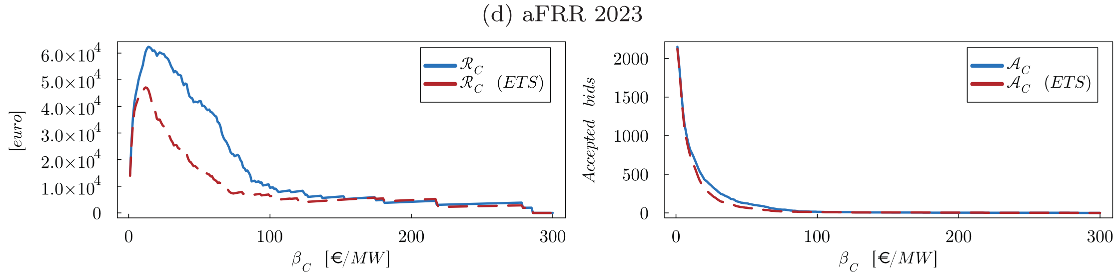
(b) aFRR 2021



(c) aFRR 2022



(d) aFRR 2023



(e) aFRR 2024

Fig. A.9. aFRR sensitivity analysis of the capacity bids (Company 1).

Data availability

The authors do not have permission to share data.

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