Carbon Markets with Chinese Characteristics: From Design to Consequences *

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This paper studies the design and consequences of China's national rate-based carbon market. Under this system, emission-intensity benchmarks create implicit subsidies for cleaner plants and taxes for dirtier ones, rotating the supply curve without changing the merit order. A theoretical model shows that, combined with strategic bidding and relatively loose benchmarks, this design weakens incentives to pass carbon costs through to electricity prices. Using detailed data from power plants and wholesale prices, we confirm that fluctuations in carbon prices have no measurable impact on electricity prices. Evidence of benchmark design and penalties suggests potential regulatory capture, so China's ETS currently operates mainly as an intra-sectoral profit transfer rather than a strong decarbonization instrument.

Key Words: Carbon Market; Tradable Performance Standard; Electricity Market; Welfare Analysis

JEL: L11, L94, H23, H32, Q41, Q54

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Abstract

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1 Introduction

China's nationwide carbon market, officially launched in 2021, is now the world's largest emissions trading system(Goulder et al., 2023). Unlike conventional cap-and-trade systems in the EU or California, it is built on a tradable performance standard (TPS), a rate-based mechanism that allocates allowances per unit of output according to emissions-intensity benchmarks (Anouliès, 2017; Fischer, 2001). These benchmarks determine which firms receive subsidies or face penalties and thereby shape both firm behavior and aggregate emissions (Pizer and Zhang, 2018). The TPS design thus creates an endogenous allocation that differs fundamentally from mass-based caps, with important implications for cost-effectiveness and distributional outcomes (Goulder et al., 2022).

At present, the national ETS covers only the power generation sector, which accounts for roughly 40% of China's CO_2 emissions (IEA, 2020; Ministry of Ecology and Environment, 2021). The sector is highly concentrated and dominated by a few large state-owned generation groups (Zhang et al., 2023). Because carbon pricing currently applies only to power plants, its ability to influence electricity prices is crucial for determining whether carbon costs are transmitted downstream to industrial users and households. Without such pass-through, the broader economy-wide impact of the ETS is likely to remain limited (Goulder et al., 2023; Yu et al., 2022).

Against this background, the paper first develops a theoretical model to study how China's TPS design affects power plant costs and electricity prices. The model shows that, under a rate-based ETS, the carbon price acts as a tax for plants with emission intensities above the benchmark and as a subsidy for cleaner plants, without changing the merit order of marginal generation costs. When this feature is combined with strategic bidding in the electricity market, carbon costs and subsidies need not be passed through to electricity prices, in contrast to the standard prediction for cap-and-trade systems where a positive marginal carbon cost is typically reflected in higher power prices (Fischer, 2001; Wang et al., 2023).

We then empirically examine the relationship between carbon prices and electricity prices using high-frequency data from several provincial power markets. Regression results show that fuel costs are almost fully passed through to real-time electricity prices under most regular conditions[1], whereas fluctuations in the national carbon price have no statistically significant effect, in sharp contrast to evidence from the EU ETS (Dagoumas and Polemis, 2020; Jouvet and Solier, 2013). These findings imply that, under current benchmark levels, China's ETS

[1]We exclude extreme conditions with ultra high or low demands to avoid corner solutions.

mainly redistributes costs and benefits within the power sector rather than inducing substantial emission reductions, and electricity end-users—firms and households—face largely unchanged prices and thus weak incentives to adjust their consumption (Goulder et al., 2023; Yu et al., 2022).

Finally, we investigate why carbon costs fail to transmit to electricity prices and provide suggestive evidence of regulatory capture in the design of China's ETS. Sectoral data from the pilot markets show that industries with higher shares of state-owned enterprises (SOEs), notably the power sector, systematically faced looser caps than other carbon-intensive sectors such as cement and steel. In the national carbon market, only a small fraction of units owned by the five major state-owned power groups are penalized, emission-intensity distributions for these SOE units bunch just below the benchmark, and unit-level carbon cost calculations reveal that large SOE generators receive disproportionately high net subsidies relative to comparable non-SOE plants. Taken together, these patterns are consistent with a regulatory-capture interpretation in which dominant state-owned incumbents influence benchmark setting and enforcement ((Xiang et al., 2023; Xu, 2011)), underscoring the importance of political economy considerations in understanding the effectiveness of China's carbon market.

Our study contributes to the literature in multiple ways. First, we provide a rigorous empirical evaluation of China's national carbon market, which remains underexplored compared to the extensive research on the EU ETS and other mature markets (Dagoumas and Polemis, 2020; Fabra and Reguant, 2014; Nazifi et al., 2021). Previous studies on China's carbon market mostly used data from China's pilot carbon markets launched in 2013, focusing on firm total emissions (Cao et al., 2021), innovation of low-carbon technology (Zhu et al., 2019), changes in energy structure (Liu et al., 2020), economic performance (Cui et al., 2021), organizational transformations (Rogge et al., 2011), etc. To our knowledge, no previous study has empirically evaluated the impacts of the national carbon trading on the electricity market in China. As the power sector accounts for approximately 40% of China's total CO_2 emissions (IEA, 2020; Ministry of Ecology and Environment, 2021), it is essential to assess whether China's national carbon market has an impact on power plants. By leveraging detailed micro-level data from multiple provinces, this study moves beyond pilot program analyses to assess the market's broader impacts on power sector behavior and emissions. The findings highlight the unique challenges posed by China's rate-based system and inform ongoing policy refinements for achieving China's ambitious climate goals.

Second, the study extends the literature on carbon cost pass-through from allowance prices

to electricity prices, a critical but understudied area, especially in the Chinese context (Wang et al., 2023). Previously, Fabra and Reguant (2014) and Hintermann (2017) investigated how carbon costs are transferred to the electricity market in the EU ETS, and both found significant carbon-cost pass-throughs. In comparison, this research documents the absence of such effects in China's TPS framework. The insight clarifies how market design and strategic bidding modulate price transmission, emphasizing the need for context-specific empirical analysis to inform market improvements.

Third, by incorporating power sector structural features and strategic bidding behavior, this paper advances theoretical understanding of tradable performance standards (Goulder et al., 2022). Compared to Goulder et al. (2022), our model distinguishes two specific components of generator emissions: emissions directly from the burning of fossil fuels and emissions abated in the power generation process, which would more accurately reflect the relationship between power generation and carbon emissions under the rate-based scheme. Furthermore, we extend previous frameworks by highlighting the interactions for marginal cost rankings, subsidy-tax heterogeneity among firms, and their strategic bidding behavior in the electricity market, reconciling theoretical predictions with empirical observations. This extension enhances the applicability of TPS theory to real-world markets, providing a foundation for better policy simulations and design optimization (Cui et al., 2021; Goulder et al., 2022).

Fourth, this research contributes new evidence on regulatory capture in China. Previous research has examined regulatory capture in multiple settings, such as the banking system (Ping, 2013), stock market (Ren, 2021), and electricity market reform (Xiang et al., 2023). Yet, little is known about how climate and carbon policies in the country are affected by interested groups. As the power industry consists mostly of large state-owned power plants, we argue that, at least partially due to regulatory capture, China's carbon markets are designed in ways that do no harm to or even benefit the large state-owned conglomerates. By providing suggestive evidence that the dominance of state-owned enterprises can shape benchmark setting and enforcement rigor, we speak to the broad literature on the consequences of regulatory capture (Dal Bó, 2006). This political economy perspective bridges environmental economics and governance research, offering a critical lens to understand institutional barriers and suggesting areas for regulatory reform (Chen and Xu, 2025).

Finally, the paper helps reconcile some puzzling empirical patterns reported previously. For example, it is well recognized that Chinese firms are not actively engaged in carbon trading, and the carbon price remains low (Zhao et al., 2017). Our findings suggest that part of the

reason is that carbon prices do not really affect electricity prices and thus play a limited role in the economy. Cao et al. (2021) and Liu et al. (2020) found that firms' emission reductions caused by the pilot carbon markets are primarily driven by reductions in production rather than technological improvements. Our paper shows that because the rate-based carbon markets do not change the market-clearing order, they will only change the production of inefficient units. By situating these patterns within the intertwined institutional and market design framework, this paper provides a unifying explanation and informs future research directions Cao et al. (2021); Goulder et al. (2023); Liu et al. (2020).

The rest of the paper is organized as follows. Section 2 provides an overview of China's carbon and electricity markets. Section 3 develops the theoretical model on how the rate-based carbon market interacts with the electricity market. Section 4 discusses the data used in the empirical analysis. Section 5 presents the empirical results. Section 6 discusses the implications of the results and the potential mechanisms. Section 7 concludes the paper.

2 Background

2.1 Carbon market in China

China began exploring carbon trading in 2013, establishing seven local pilot schemes in major cities and provinces, including Beijing, Tianjin, Shanghai, Chongqing, Hubei, Guangdong, and Shenzhen. These pilots were designed to test market mechanisms and build institutional capacity before scaling to the national level. Empirical studies consistently find that the pilot carbon markets delivered significant emission reduction effects, achieving up to a 16–18% drop in carbon intensity for regulated firms compared to non-pilot regions (Cui et al., 2021; Liu et al., 2023). In addition to reducing CO_2, pilot policies contributed to lower emissions of other pollutants, promoted energy efficiency, and—in some regions—supported high-quality, stable economic development (Hong et al., 2022; Zeng et al., 2024). However, impacts on employment and industrial output were mixed, with some evidence of productivity gains but also short-term labor and investment costs associated with compliance (Cui et al., 2021). Furthermore, scholars note heterogeneity in pilot effectiveness across locations, often shaped by local policy design and the relative share of state-owned enterprises (Zhang et al., 2023).

Building on the pilot experience, China launched its national Emissions Trading System (ETS) in July 2021, transitioning toward a unified national mechanism. By the end of 2022, the ETS covered roughly 3.5 billion tons of CO_2 emissions annually—making it the world's largest

carbon market by coverage, nearly double the EU ETS (1.8 billion tons). Initially, the market covers about 2,200 entities from the power sector alone, accounting for over 40% of the country's emissions (Ministry of Ecology and Environment, 2021; Zhang et al., 2025). Distinctively, China's system employs a rate-based allocation, using emissions intensity benchmarks for free allowance distribution, as opposed to the cap-and-trade approaches used elsewhere(Goulder et al., 2022). This approach is seen as accommodating rapid economic growth while incentivizing efficiency upgrades, but it also means total emissions are not capped absolutely in the market.

China's ETS has the potential for future reform and expansion. Policymakers have signaled plans to convert the system into a true cap-and-trade regime with absolute emission caps, extend coverage to more sectors—such as steel, cement, and petrochemicals—and gradually increase the share of allowances that are paid instead of free (Yu et al., 2024). While the ETS has brought China to the forefront of global carbon trading, challenges remain: trading liquidity remains low compared to the EU, allowance prices are about one-tenth those in Europe, and the benchmark intensity design dilutes the scheme's emission-cutting power (Goulder et al., 2022; Zhang et al., 2025). The emission intensity benchmarks[2] for various types of power plants from 2020 to 2024 are presented in Table 1.

Table 1: China's Carbon Intensity Benchmark (tCO_2/MWh)

	2020	**2021**	**2022**	**2023**	**2024**
Coal-fired units ($> 300MW$)	0.877	0.822	0.818	0.786	0.782
Coal-fired units ($\leq 300MW$)	0.979	0.877	0.873	0.798	0.794
Unconventional coal-fired units	1.146	0.935	0.930	0.808	0.804
Gas-fired units	0.392	0.392	0.390	0.331	0.329

2.2 Electricity Market in China

Historically, China's power sector was a vertically integrated and state-owned monopoly. The government directly controlled generation, transmission, distribution, and electricity prices nationwide, with little room for market forces (Ngan, 2010). As rapid economic growth led to exploding electricity demand, a series of reforms were launched to modernize the sector. The first major market-oriented step came in 2002, when the Chinese government implemented the "separation of generation from the grid" policy, unbundling state-owned utilities into independent power producers and grid companies, and laying the foundation for a market-based trading

[2]Note that the carbon allowances are allocated free of charge to participating enterprises.

mechanism. However, early reform efforts were hampered by persistent electricity shortages and system reliability concerns, which limited the extent of market competition (Wang and Chen, 2012).

A new phase began with the issuance of the "Several Opinions on Further Deepening the Reform of Electric Power System" (commonly known as Document No. 9) in 2015, catalyzing comprehensive efforts to establish competitive electricity markets (Guo et al., 2020). Eight provinces initiated pilot spot markets based on competitive pool models, incorporating both day-ahead and real-time trading. The core market design features merit-order dispatch, where generation companies (GenCos) submit price–quantity bids to an Independent System Operator (ISO), which then arranges bids from lowest to highest to meet demand at the lowest system cost (Bower and Bunn, 2000). Thus, plants with higher efficiency and lower marginal costs are dispatched first, promoting allocative efficiency and incentivizing technical upgrades.

Progress accelerated in 2021, when the government partially abolished the regulated electricity tariff catalog for most industrial and commercial customers, marking a decisive shift toward market-based pricing. This liberalization excluded only public services, agriculture, residential users, and other protected groups, but dramatically increased the share of electricity transacted in markets. By 2024, over 60% of electricity consumption was traded on the market, compared with less than 20% just a decade earlier. The coexistence of day-ahead and real-time markets creates arbitrage opportunities and increases market efficiency (Krishnamurthy et al., 2018).

2.3 Determinants of Electricity Price in China

Electricity prices in China are shaped by a combination of fuel costs, market conditions, and policy frameworks. Among these, coal prices remain the most direct and dominant factor, as coal-fired power plants still account for over 55% of total electricity generation. Domestic thermal coal prices—particularly those under long-term supply contracts—act as a "cost stabilizer," whereas fluctuations in spot coal markets directly affect electricity generation costs and wholesale market prices (RMI, 2025). For instance, changes in Qinhuangdao 5,500 kcal coal prices, which have ranged between 690 and 940 RMB/ton in recent years, strongly influence the clearing prices in power spot markets.

Natural gas and oil prices also affect market dynamics, especially in coastal and southern provinces where gas-fired generation plays a significant balancing role. When international LNG prices rise, gas-fired plants are less competitive, shifting marginal generation back to coal and

driving up emission intensity (China Electricity Council, 2025).

Beyond fuel inputs, renewable energy integration increasingly influences price formation. The rapid increase of low-marginal-cost solar and wind power has pushed real-time market prices downward during off-peak or high-renewable-output hours, occasionally leading to "negative prices" in provinces such as Shandong and Zhejiang in early 2025 (Dialogue Earth, 2025).

Additionally, demand fluctuations, seasonal hydropower output variability, and climate conditions (such as extreme heat or drought) impact supply-demand balance and price volatility. Policy-driven factors—like transmission tariffs, capacity payments for coal units, and time-of-use pricing for commercial and residential users—further shape electricity costs.

Overall, China's electricity pricing reflects an evolving equilibrium between fuel cost pass-through, renewable supply expansion, and regulatory transition. As power market liberalization deepens and fossil fuel price volatility continues, electricity price formation is expected to become more market-responsive but also more exposed to energy commodity swings (China Electricity Council, 2025; RMI, 2025)

2.4 Link between Carbon Market and Electricity Market

Power generation is the largest source of carbon emissions in China, so the ability of carbon costs to transmit through electricity prices is pivotal to incentivizing both generators and end users to reduce emissions and improve efficiency. Extensive research shows that higher electricity prices can encourage end users to adopt energy-saving technologies or shift demand, broadening the societal impact of carbon markets Blaschke (2022); Linn (2008).

The literature on carbon cost pass-through to electricity prices mostly focuses on the EU and other cap-and-trade (C&T) systems, where evidence shows a significant and direct reflection of CO_2 prices in wholesale power prices (Dagoumas and Polemis, 2020; Jouvet and Solier, 2013; Nazifi et al., 2021). In these systems, marginal fossil fuel-based generators set market-clearing prices, and higher carbon costs are rapidly transmitted to consumers. However, as we will show in the following sections, China's rate-based approach—using emissions intensity benchmarks and free allowance allocation—may create uncertainty for the carbon cost pass-through. Empirically, Wang et al. (2023) analyzed nationally aggregated data and found no clear linkage between carbon costs and electricity prices. It is generally recognized that as allowance allocation shifts towards a greater auction share, as the emission intensity benchmarks rise, and as market reforms deepen, carbon costs are more likely to be passed through to the electricity prices (Wang et al., 2023; Zhang et al., 2025). However, much of the discussion on

this issue has been quantitative so far. This paper provides a theoretical foundation for such arguments.

3 Theoretical Model

3.1 Set-up

Our theoretical model builds on the static framework in Goulder et al. (2022), considering a generator's net revenue in the context of China's electricity and carbon markets. China's electricity market employs a Contract for Difference (CFD) arrangement: each generator receives a guaranteed price $\bar{p}_i$ for a contracted quantity $\bar{q}_i$ through long-term agreements, which covers a substantial portion of plant capacity.[3] The remainder can be traded in the market, and any gap between the contract price and the realized market-clearing price p is either refunded to or supplemented for the generator on the contracted amount (Jin et al., 2020). Additionally, demand for certain sectors—agricultural, residential, and public services—is set and protected by policy. The static profit function for generator i is,

$$\pi_i = \bar{p}_i \bar{q}_i + p(q_i - \bar{q}_i) - C_i(q_i, a_i) - \lambda(e_i - W_i) \tag{3.1}$$

$$e_i = E_i(q_i) - a_i \tag{3.2}$$

$$W_i = Bq_i \tag{3.3}$$

where $\bar{q}_i$ is the contracted quantity (long-term agreement at price $\bar{p}_i$); q_i is the total generated quantity by generator i; p is the market-clearing price[4]and is determined by total supply and demand and is generally exogenous.[5] C_i is the cost function of generator i, dependent on the output q_i and abatement effort a_i;[6] λ represents the carbon allowance price, which can be treated as exogenous at national level, since the price is set by aggregate supply and demand of allowances; e_i and W_i denote the total emissions and allowances allocated to generator i respectively.

Here, $E_i(q_i)$ is the emissions as a function of output, and a_i is emission abatement. Allowance allocation W_i is determined by multiplying total generation by a benchmark emissions

[3]According to the latest requirement of the central government, the coverage of long-term contracts need to reach 85% for thermal power plants to achieve a stable electricity price.

[4]The ordered bidding price would form an increasing supply curve, as shown in Figure 8 Thus, the bidding price vector $\mathbf{p_i}$ would eventually construct one clearing price. p can be written with a timely feature as p_t, to showcase the prices during different periods.

[5]See section 3.3 for more details.

[6]We also set both C_q and C_{a_i}, the marginal cost of generation and emission reduction, positive.

intensity B, set by regulators (see Goulder and Morgenstern (2018)). This benchmark—varying with plant technology and capacity—forms the core of China's rate-based carbon allocation system (Jin et al., 2020; Zhang et al., 2021).

Notably, the model departs from earlier work by explicitly linking emission decisions with generation q and abatement a, reflecting the nature of China's market, which included mainly coal-fired power plants as key emission sources (Goulder et al., 2022).

Unlike some prior models, the possibility that $q_i < \bar{q}_i$ is incorporated: when a generator fails to secure enough market generation, it can meet obligations by purchasing from other generators—typically more efficient plants. Under competitive bidding, inefficient generators are likely dispatched less, raising system efficiency (Jin et al., 2020).

Finally, whether the carbon price effectively acts as a subsidy or a tax for a generator depends on the benchmark's relationship to firm emissions. If a plant is cleaner than the benchmark, it receives surplus allowances and an implicit subsidy; if dirtier, it must buy extra, effectively taxed. This allocation deeply affects bidding strategies and market outcomes (Goulder et al., 2022; Jin et al., 2020).

3.2 Impact from the carbon market

Carbon Cost and Electricity Price Given the uncertainty and nearly exogenous market-clearing price p, each generator optimizes its production q_i and emission abatement a_i to maximize profit in the short term.[7] Combining Equations 3.1, 3.2, and 3.3, the net profit for generator π_i under the rate-based scheme becomes:

$$\pi_i = \bar{p}_i\bar{q}_i + p(q_i - \bar{q}_i) - C_i(q_i, a_i) - \lambda(E_i(q_i) - a_i - Bq_i) \tag{3.4}$$

This structure reflects the marginal effect of both market price and carbon price on the generator's decisions (Goulder et al. (2022); Jin et al. (2020)). The first-order condition of equation 3.4 are,

$$\frac{\partial \pi}{\partial a_i} : C'_{a_i} = \lambda \tag{3.5}$$

$$\frac{\partial \pi}{\partial q_i} : p = C'_{q_i} + \lambda(E'_{q_i} - B) \tag{3.6}$$

[7]Firms would also adjust their bidding price as one critical part of its strategy. However, it is highly dependent on the generation cost. See section 3.3 for details. For long-term optimization, firms can also decide whether to upgrade their technology to reduce the cost and emission, affecting the cost function C and emission function E.

Equation 3.5 is intuitive that firms reduce emissions to the point where the marginal cost of abatement equals the carbon price λ. Thus, the carbon market directly promotes the adoption of emission reduction measures (Cui et al., 2021).

Equation 3.6 describes the interplay between carbon and electricity markets. High-emission generators (with intensities above benchmark (B)) incur higher production costs—specifically, an extra cost of $\lambda(E'_{q_i} - B)$, analogous to a tax. Meanwhile, low-emission units receive an implicit subsidy. This result diverges from standard cap-and-trade findings; in China's rate-based scheme, some firms are effectively subsidized (Goulder et al., 2022; Jin et al., 2020).

An important innovation is that, if the supply-demand intersection in the electricity market is to the left of the benchmark point, carbon trading may even lower the market price—i.e., marginal subsidies can outweigh marginal taxes for some market-clearing scenarios. In this framework, competitive bidding implies that firms with lower costs (where $p > C'_{q_i} + \lambda(E'_{q_i} - B)$) maximize output. High-emission plants, facing higher costs, decrease their generation, enhancing overall system efficiency. Figure 1 visually demonstrates how rate-based trading rotates the supply curve around the benchmark.

3.3 Merit Order, Bidding, and Carbon Cost Pass-Through

Due to the "merit order" effect (McConnell et al., 2013), the market-clearing price in the electricity market is governed by the intersection of aggregate demand and the supply curve. When generators face heterogeneous cost impacts—such as those introduced by a rate-based carbon market—they have incentives to adjust markups in their bidding strategies to seek arbitrage opportunities and increase profits (Kim, 2022). The carbon subsidy or tax a generator receives depends on the gap between its actual emission intensity and the benchmark. Generators positioned further from the intersection point of the standard and the supply curve experience a greater subsidy or tax, as depicted in Figure 2.

This logic is reflected in the profit expression for generator (Equation 3.6) under imperfect competition:

$$\pi_i = P(p_i, q_i, \mathbf{p_{-i}}, \mathbf{q_{-i}})(Q_i(P(p_i, q_i, \mathbf{p_{-i}}, \mathbf{q_{-i}})) - \bar{q}_i) + \bar{p}_i\bar{q}_i - C_i(Q_i, a_i) - \lambda(E_i(Q_i) - a_i - BQ_i) \quad (3.7)$$

where P is the market-clearing price derived from all generators' bids, and Q_i is the output secured by p_i and q_i, and $\mathbf{p_{-i}}$ and $\mathbf{q_{-i}}$ are rivals' strategies.

Assuming symmetric information, which is plausible given China's centralized reporting and personnel rotation among power groups, generators can well anticipate the cost structure

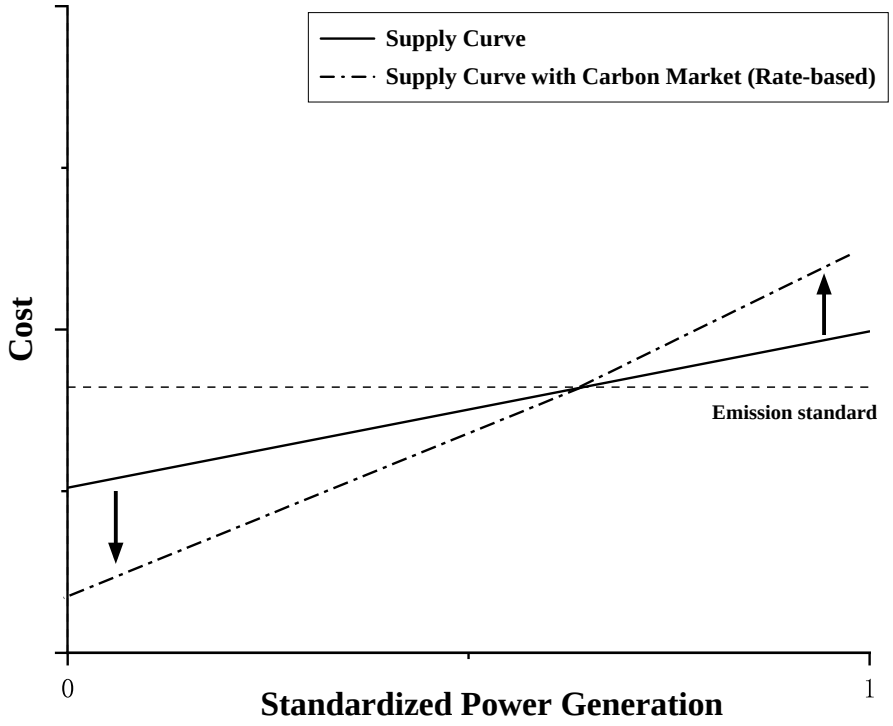


Figure 1: How Rate-based Carbon Trading Affects Supply Curve in the Electricity Market.

Notes: The horizontal axis represents the standardized generation of each generator, while the vertical one is the generation cost. The ordered cost forms a supply curve. The dashed line is the new supply curve after accounting for the carbon cost.

facing other market participants. This creates space for strategic bidding and warranting mark-up adjustments to exploit carbon subsidies or minimize regulatory burden (Ito and Reguant, 2016). The market-clearing price in a rate-based carbon market, as described in Equation 3.7, depends on each generator's bidding strategy and their rivals' strategies.

Figure 3 provides a graphical depiction of how the intersection points of demand and supply curves affect the pass-through rate of carbon costs. In panel (a), when the generator after the clearing generator (generator D) receives a carbon subsidy greater than the adjacent generation cost differential, the clearing generator (generator C) may partially pass its carbon cost (subsidy) to preserve its market position. In panel (b), if generator D's subsidy is less than the generation cost differential, the clearing generator has no incentive to adjust its bid price. Finally, panel (c) shows both generator C and D facing carbon taxes; in this scenario, carbon costs can be fully passed through to the electricity price.

This theoretical framework also enables comparison of generator bidding strategies under different carbon market schemes by defining the form of emission allowances W_i. Under the

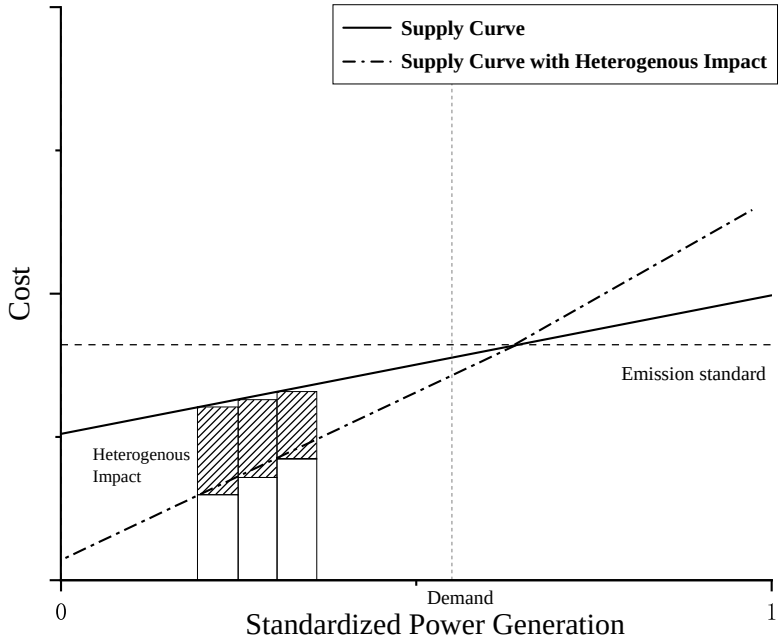
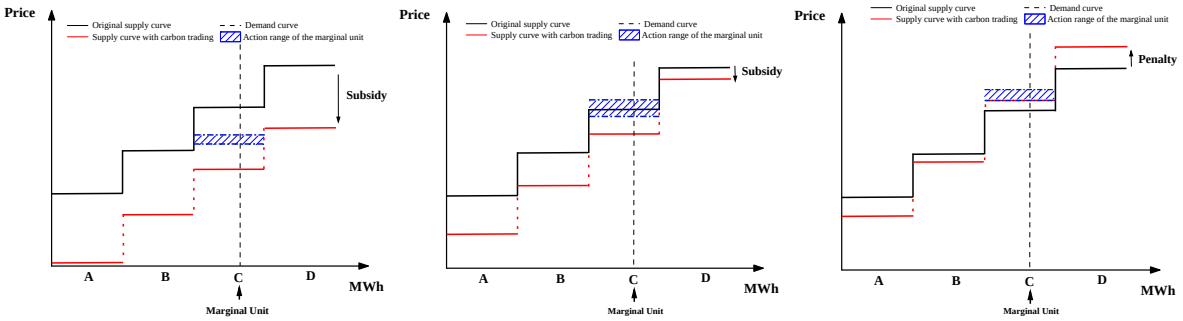


Figure 2: Heterogeneous Impact on the Supply Curve in the Electricity Market.

Notes: The horizontal axis represents the standardized generation of each generator. The vertical one is the generation cost. Generators will receive the heterogeneous impact in a rate-based carbon market.



(a) Partial carbon cost pass-through (b) No carbon cost pass-through (c) Full carbon cost pass-through

Figure 3: Bidding Strategy and Carbon Cost Pass-through.

Notes: The black curve is the original supply curve. The red curve is the supply curve with carbon trading. The blue dotted line represents the bidding strategy made by the clearing generator. The dashed line is the demand curve.

traditional cap-and-trade (C&T) scheme, allowances are fixed quantities assigned based on historical emissions or generation performance, making them exogenous to current production decisions (Anouliès, 2017; Lutz et al., 2013). For a generator governed by C&T, the profit function is expressed as:

$$\pi_i = \bar{p}_i \bar{q}_i + p(q_i - \bar{q}_i) - C_i(q_i, a_i) - \lambda(E_i(q) - a_i - W_i) \tag{3.8}$$

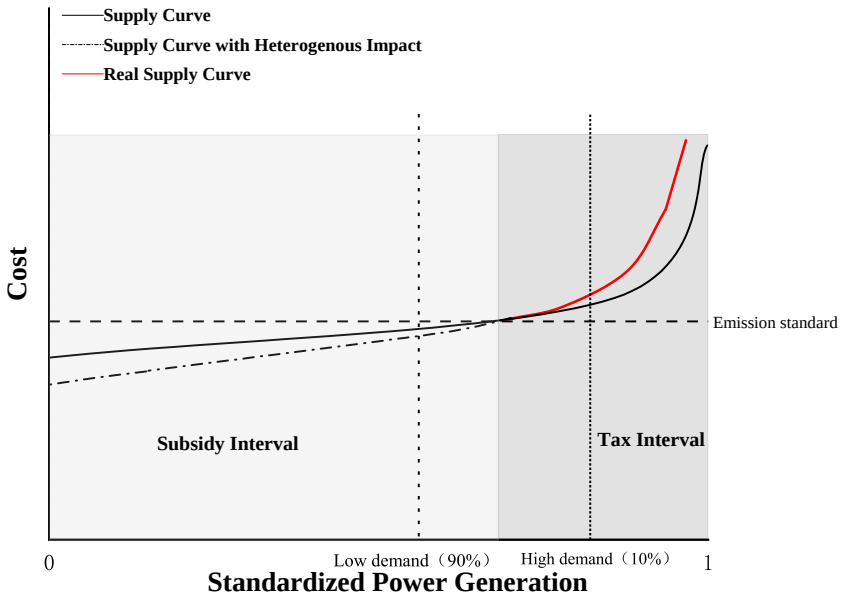


Figure 4: The Expected Supply Curve in the Electricity Market after Heterogeneous Impact.

Notes: The horizontal axis represents the standardized generation of each generator, while the vertical one is the generation cost. The ordered cost forms a supply curve (black line). The red line indicates that generators would adjust their markups for profit maximization and eventually form a kinked supply curve.

where the emission term e_i from Equation 3.1 is replaced with its explicit form $E_i(q_i) - a_i$.

The first-order conditions for emission abatement and output decisions are:

$$\frac{\partial \pi}{\partial a_i} : C'_{a_i} = \lambda \tag{3.9}$$

$$\frac{\partial \pi}{\partial q_i} : p = C'_q + \lambda E'_q \tag{3.10}$$

The condition governing abatement a_i is similar to that under the rate-based scheme, implying firms reduce emissions until the marginal abatement cost equals the carbon price λ. However, the output condition shows a key difference: under C&T, firms face a direct carbon cost proportional to their marginal emissions E'_q without any subsidy. Firms internalize these costs in their bidding, passing them onto electricity prices. This aligns with Fabra and Reguant (2014), who found that under inelastic short-term demand, carbon costs are reflected in wholesale power prices. This difference explains why carbon price pass-through should be stronger under cap-and-trade systems than under rate-based schemes.

3.4 Summary of Theoretical Findings

This section summarizes the insights from the theoretical model. Since the rate-based scheme allocates allowance by setting the benchmark, generators would receive heterogeneous

cost impacts, either a subsidy or a tax, from carbon trading. The subsidized firms would expand generation and eventually squeeze the market of taxed ones from the electricity market competition.

Such a situation would further drop the carbon price, as the allowance demand is dependent on the production of taxed generators. The low carbon price would prevent the development of carbon reduction technologies due to the unbalance between marginal benefits and costs. Moreover, facing heterogeneous cost impact, agents would conduct arbitrage strategies in the electricity market. However, firms would balance the trade-off between the limited carbon costs due to the low allowance price and the market uncertainty. Therefore, the carbon pass-through becomes uncertain and could even be missing.

In summary, though the carbon market would affect individual firms' generation cost, whether it would impact China's electricity sector and thus the economy via the electricity price, remains uncertain. First, the electricity market interaction point might be on the left part, and the tax becomes a subsidy. Second, the current carbon price (about 5 euros/ton) might be too low to affect firms' bidding strategies. Last but not least, the risks in electricity competition would prevent firms from arbitrating limited profits. The special features of electricity generation, such as continuous generation and high long-term contract coverage would further lead to extremely aggressive low-bidding price strategies, i.e., the negative market price in Europe and the US (Jha and Leslie, 2025; Seel et al., 2021; Valitov, 2019). Based on these findings, we empirically test whether carbon trading would drive significant changes in electricity prices in the subsequent sections.

4 Data

Our empirical analysis combines several high-frequency and plant-level datasets to characterize the operation of China's electricity and carbon markets. We first construct a province-level panel of real-time electricity prices, matched with the national carbon price series and major fuel input prices (coal and natural gas). We then incorporate detailed information on electricity demand and renewable generation to capture load fluctuations and the impact of variable renewable energy on price formation. Finally, we assemble unit-level technical and emissions data for thermal power plants, which allows us to document heterogeneity in efficiency and carbon intensity across units and to study how the national ETS redistributes costs among different types of generators.

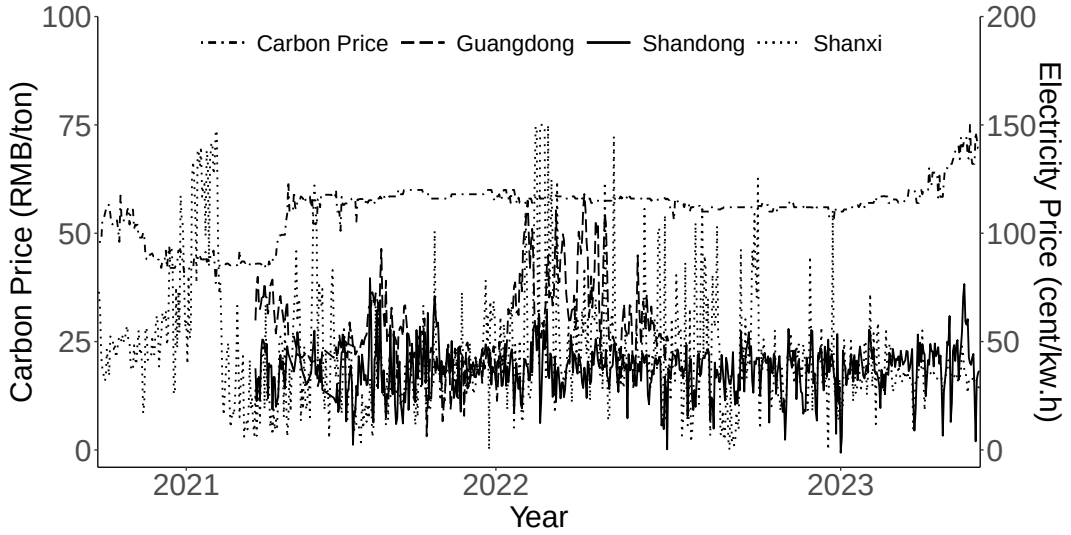


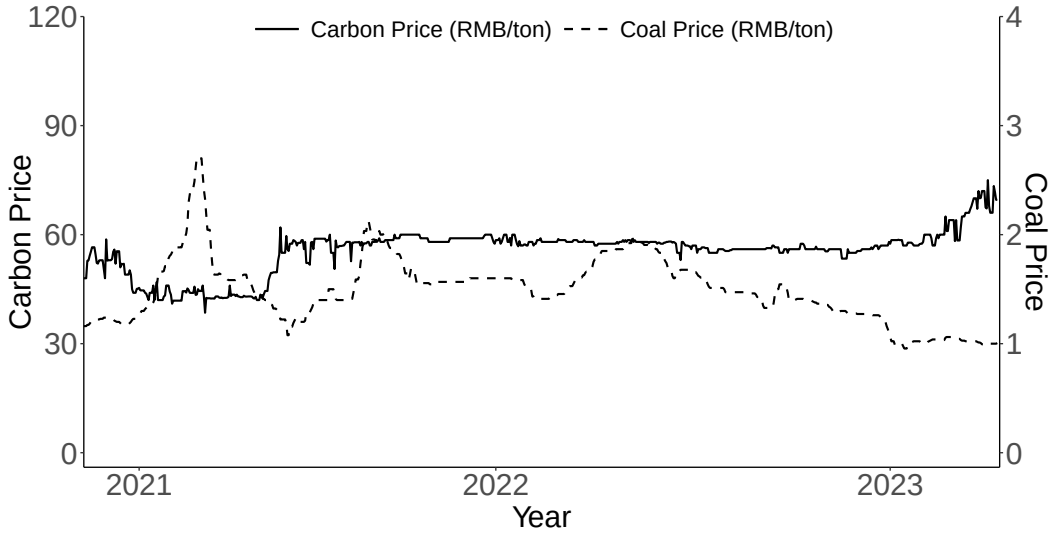
Figure 5: The National Carbon Price and Provincial Electricity Prices in Shandong, Shanxi, and Guangdong.

Notes: This figure depicts the opening price in the national carbon trading market and the daily average real-time electricity prices in Shanxi, Guangdong, and Shandong, respectively.

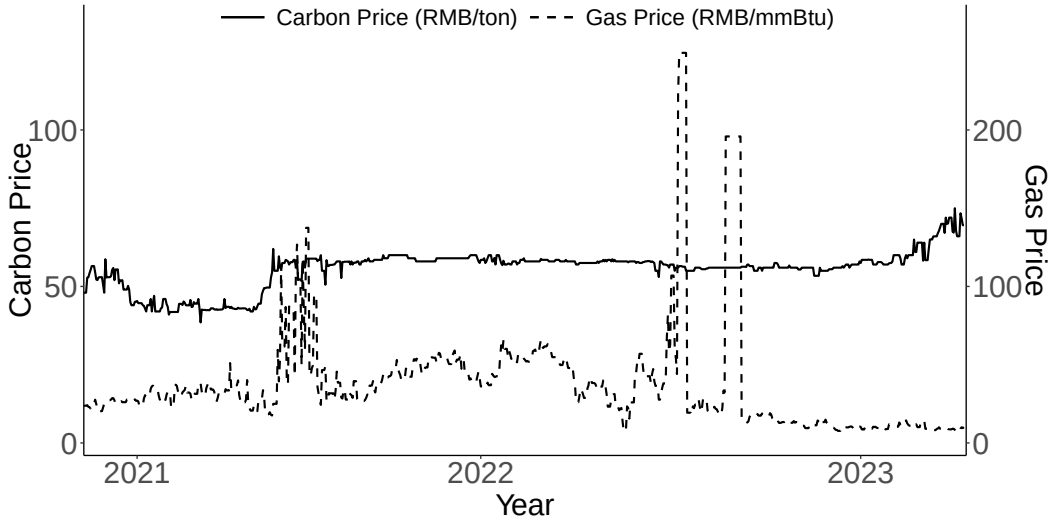
4.1 Real-time Electricity Price

We primarily use real-time electricity price data from the *DianChaCha* website.[8] Prices are recorded at a 15-minute frequency, yielding 96 observations per day.[9] The dataset contains between 30,000 and 100,000 real-time price observations for Guangdong, Shandong, and Shanxi.

Figure 5 plots the time series of the national carbon price alongside provincial real-time electricity prices in these three provinces. The carbon price remains relatively stable between 2022 and 2023, with two noticeable spikes in early 2022 and the summer of 2023. The highest level reaches about 75 CNY/ton in August 2023, followed by moderate fluctuations. Electricity prices, by contrast, display considerably more variation: prices in Shanxi and Guangdong often exceed 150 cents/kWh, while prices in Shandong fluctuate around 40 cents/kWh. Visually, Figure 5 does not suggest a clear co-movement between the carbon price and provincial electricity prices.



(a) Coal



(b) Gas

Figure 6: Carbon, Coal, and Gas Price Dynamics.

Notes: The black solid curve shows the opening price in the national carbon market. Since coal futures trading data in China was suspended in late 2022, we use the imported thermal coal price at Shanghai Harbor as a proxy for coal prices. The gas price is the NOWGAS index from the New York futures market.

4.2 Carbon, Coal, and Gas Prices

Carbon Price The carbon price is one of the core explanatory variables in our analysis. Daily national allowance prices are obtained from the *Wind* database. The series starts on July

[8] `https://dianchacha.cn/transaction`. The original data are reported by the Provincial Electric Power Trading Centers.

[9] Shandong is a special case. The market only clears hourly prices, so all four 15-minute observations within an hour take the same value.

16, 2021, the first trading day of the national ETS. In the empirical analysis, we use the daily opening price as our main measure of the carbon price.

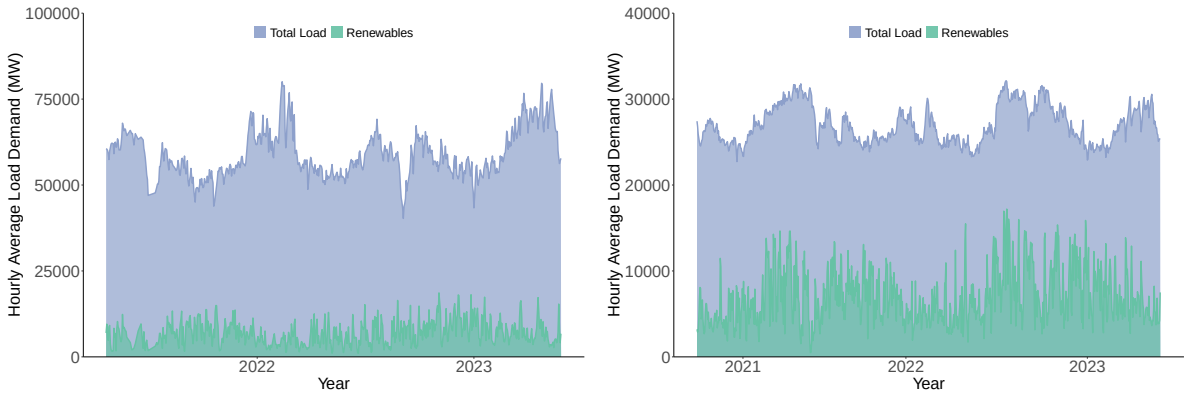
Coal Price Coal is the dominant fuel input in China's power generation mix and therefore a key determinant of generators' bidding strategies, as fuel costs account for a large share of total generation costs. To control for input cost shocks, we include coal prices in our empirical models. Due to the sharp increase in domestic coal prices from 2021 to 2022, trading in coal futures was suspended in September 2022. We therefore proxy coal costs using the spot prices of imported thermal coal at Shanghai Harbor.[10] This series is well suited to capture the underlying trend in input coal costs, especially given the production origin in Shanxi. The evolution of this price is shown as the dash line in Figure 6 (a). Because plant- or province-specific fuel procurement costs are not observable, we also conduct robustness checks using alternative coal price series, including prices at Guangzhou Harbor (Guangdong), Datong (Shanxi), and Zaozhuang (Shandong), which are among the main coal trading hubs in China.

Gas Price Although gas-fired generation accounts for a relatively small share of total electricity supply in China, we also control for natural gas prices to ensure robustness. Gas prices are obtained from the New York futures market (NOWGAS index) and converted into CNY using the exchange rate as of May 8, 2025. This variable captures international gas cost shocks that may affect the competitiveness of gas-fired units in coastal regions.

4.3 Electricity Demand and Renewable Generation

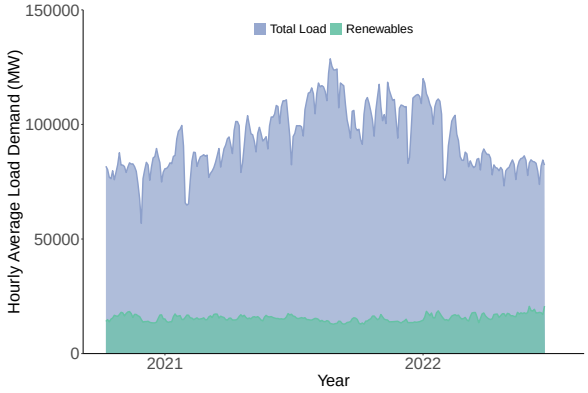
Following Fabra and Reguant (2014), we treat electricity demand as a key explanatory variable. In addition, we account for renewable generation, given the well-documented impact of variable renewable energy on electricity prices (Dillig et al., 2016; Weber and Woerman, 2024). Both electricity demand and renewable generation data are obtained from *DianChaCha.com*. The sample period for these series is aligned with the real-time price data, and the raw frequency is 15 minutes. For the baseline empirical analysis, we aggregate these variables to the daily level. Figure 7 plots the average daily load and renewable generation in each province. On average, renewable generation covers roughly 10% of total load in Shandong, Shanxi, and Guangdong.

[10] NO.4 Thermal Coal, 5,800 kcal/kg, produced in Datong, Shanxi province. Detailed data are available at `https://www.cctd.com.cn/list-167-1.html`. Membership access may be required.



(a) Shandong

(b) Shanxi



(c) Guangdong

Figure 7: Average Load Demand and Renewable Generation in Shandong, Shanxi, and Guangdong.

Notes: The blue area shows the hourly average load in each day; the green area indicates hourly renewable generation.

4.4 Thermal Power Units

Table 2 summarizes unit-level characteristics for thermal power plants in Shandong, Shanxi, and Guangdong. We match individual generating units across multiple government-published sources.[11] Details of the matching procedure are provided in Appendix A.

As shown in Table 2, the generation structures of Shandong and Shanxi are quite similar. More than 80% of coal-fired units have capacities below 300 MW, which typically implies lower efficiency and higher carbon intensity. Consequently, in both provinces, small units (capacity $\leq$ 300 MW) account for a larger share of annual coal-fired generation than large units (capacity $>$

[11] Data sources: *Compilation of Statistics on the Electric Power Industry* and *National Unit Energy Efficiency Competition Data*.

300 MW). Gas-fired units are relatively scarce in Shandong and Shanxi. Their average emission intensity is substantially lower—about one-third of that of coal-fired units. In Guangdong, gas-fired units represent roughly one quarter of all units in number but contribute only about one seventh of total electricity generation.

Energy efficiency differences across provinces are central to our analysis. Units in Shandong exhibit lower average carbon intensity than those in Shanxi: in 2021, average emission intensities are 740.22 gCO_2/kWh and 784.38 gCO_2/kWh, respectively. Guangdong has the lowest average intensity, at 681.27 gCO_2/kWh, largely due to its higher share of gas-fired capacity.

Table 2 also reports the number of units participating in the national ETS in 2021 and the number exceeding the relevant emission benchmarks. In all three provinces, more than 80% of units are covered by the ETS. However, only about 20–25% of units meet or exceed the benchmark, and these are predominantly small units.

Figure 8 compares each unit's carbon emission intensity with the corresponding benchmark. The width of each bar represents the standardized electricity output of a unit in 2021,[12] and the height reflects its emission intensity. Bars are sorted in ascending order of intensity. The black dashed lines indicate the benchmark values.[13] Specifically, the benchmark is 821.8 gCO_2/kWh for units above 300 MW (dashed lines in panels (a), (c) and (e) 877.3 gCO_2/kWh for units below 300 MW (dashed lines in panels (b), (d) and (f)).

For units larger than 300 MW, none of the generators in Shandong exceed the benchmark. In Shanxi, only a small share of large units are above the benchmark, contributing roughly 10% of total generation. For units below 300 MW, about one fifth exceed the benchmark, but together they account for only 10–15% of provincial generation. Overall, Figure 8 indicates that the emission intensity benchmarks are relatively lenient, and only a limited subset of coal-fired units are effectively "taxed." Moreover, the vast majority of these non-compliant units are not owned by the five major state-owned power generation groups (light gray bars), suggesting that large central SOEs are rarely penalized under the current ETS design.

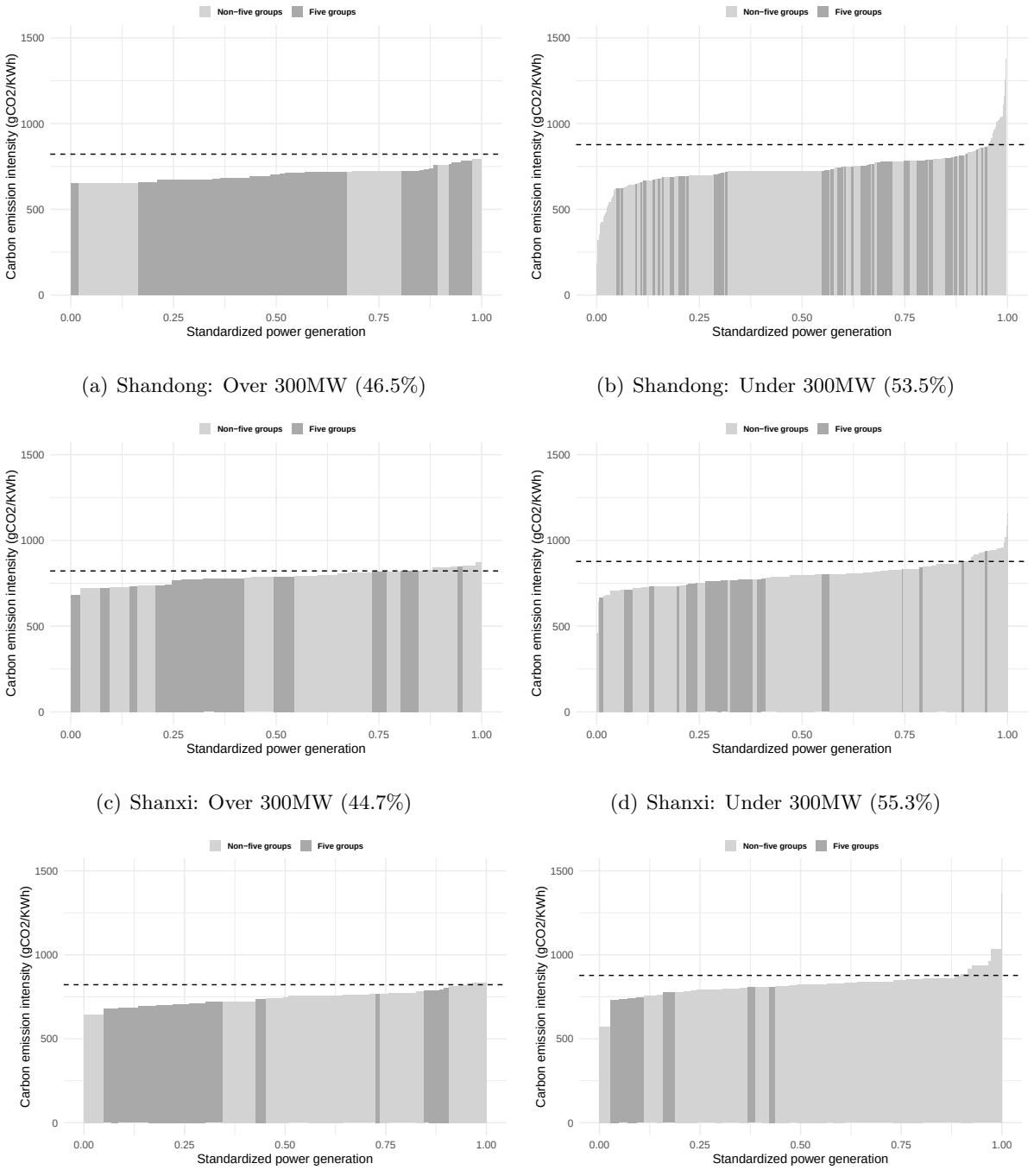
[12] We divide each unit's annual generation by total provincial generation, so the cumulative width increases from 0 to 1.

[13] Benchmarks are taken from the *Implementation Plan for the Total Cap and Quota Allocation for the 2021 and 2022 National Carbon Emissions Trading.*

Table 2: Basic Information of Power Units in Shandong, Shanxi and Guangdong Province

	Number of units		Number of units in the ETS		Number of units beyond emission standard		Annual Electricity Production (billion kWh)		Average Utilization hours (h)		Average Emissions Intensity (gCO_2/kWh)	
	(2019)	(2021)	(2019)	(2021)	(2019)	(2021)	(2019)	(2021)	(2019)	(2021)	(2019)	(2021)
Shandong												
Coal-fired Plants												
Capacity >300MW	49	63	N/A	54	0	0	176.800	241.298	4843	5070	731.508	705.08
Capacity ≤300MW	430	415	N/A	325	86	68	280.269	278.028	3965	3931	839.781	748.628
Gas-fired Plants	-	-	N/A	-	-	-	-	-	-	-	-	-
Total	479	478	N/A	379	86	68	457.069	519.326	4055	4081	828.705	740.220
Shanxi												
Coal-fired Plants												
Capacity >300MW	41	49	N/A	39	0	12	115.090	131.540	4597	4359	796.720	789.278
Capacity ≤300MW	127	125	N/A	111	16	26	149.719	158.875	4352	4533	985.665	808.788
Gas-fired Plants	6	6	N/A	6	0	0	4.234	3.867	2464	2243	290.509	261.214
Total	174	180	N/A	156	16	38	269.043	292.282	4344	4410	917.173	784.376
Guangdong												
Coal-fired Plants												
Capacity >300MW	54	64	N/A	60	0	4	165.400	257.916	3883	5103	763.275	750.833
Capacity ≤300MW	73	67	N/A	63	1	11	89.012	95.344	4400	5055	833.2	834.6
Gas-fired Plants	39	49	N/A	28	15	4	40.255	62.714	3172	3154	389.557	380.835
Total	166	180	N/A	151	16	19	294.667	415.975	3943	4554	706.566	681.274

Note: According to *the National Carbon Emissions Trading Quota Total Setting and Allocation Implementation Plan*, Capacity $\geq$ 300MW refers to generators with a rated capacity greater than 400MW. The same applies to Capacity $\leq$ 300MW. The CO_2 emission coefficients converted from standard coal for coal-fired power generation and natural gas power generation are 2.493kg-CO2/kg-ce and 1.6275kg-CO2/kg-ce, respectively.



(a) Shandong: Over 300MW (46.5%)

(b) Shandong: Under 300MW (53.5%)

(c) Shanxi: Over 300MW (44.7%)

(d) Shanxi: Under 300MW (55.3%)

(e) Guangdong: Over 300MW (62.0%)

(f) Guangdong: Under 300MW (30.2%)

Figure 8: Ordered Carbon Intensity of Generators in Shandong, Shanxi and Guangdong.

Notes: Generators over and under 300 MW are separately presented with their corresponding emission standard rates. The width of each bar shows the standardized annual production of the corresponding generators in 2021, and the height is the carbon emission intensity. The dashed line demonstrates the emission standard for allowance allocation of each group. The percentage in brackets is the proportion of the power generation of the corresponding type of unit to the total power generation. The dark grey bar/light grey bar differentiates the ownership group of generators.

5 Empirical Studies and Results

Building on the theoretical analysis, we conduct a series of empirical tests to examine how the carbon market affects the electricity market and. First, we compare marginal generation cost differentials with marginal carbon costs to infer the bidding incentives of marginal units. Next, we estimate the pass-through rates of coal and carbon costs into electricity prices. Finally, we run panel regressions using daily and 15-minute real-time prices to assess whether fluctuations in carbon and fuel costs are statistically associated with electricity prices.

5.1 Marginal Cost Comparison

Because generators can adjust their markups to increase profits, there is, in principle, an incentive to pass carbon costs through to electricity prices, regardless of whether the marginal unit receives a tax or a subsidy. However, if the unit immediately behind the clearing generator receives a subsidy that is smaller than the underlying generation cost difference between the two units, the marginal generator has no incentive to alter its bid: even if the carbon cost (or subsidy) were fully passed through, the adjacent unit's cost would still not reach the cost level of the clearing unit. In this case, carbon cost pass-through is effectively absent. For this reason, comparing marginal generation cost differences with marginal carbon costs for adjacent generators is crucial.

Identification of Marginal (Clearing) Generators Market clearing in the electricity spot market follows the merit-order principle. We identify the marginal generator using the following procedure: (1) sort all generators from lowest to highest generation cost; (2) cumulatively sum their installed capacities, starting from the lowest-cost unit, until the cumulative capacity meets total load;[14] (3) define the marginal generator as the last unit needed to satisfy the load, and its generation cost as the clearing cost. Using this approach, we construct 15-minute marginal generators for Shandong, Shanxi, and Guangdong. This procedure yields a lower bound on the generation cost in provincial markets, as it assumes all low-cost generators can operate at will. In practice, technical constraints such as grid conditions, ramping limits, and unit start-up requirements may push actual clearing costs above this lower bound.

[14]To reflect priority access for renewable energy mandated by the government, we deduct renewable generation from total load. Furthermore, imports from and exports to other provinces are excluded. The remaining net load is assumed to be cleared in the spot market.

Marginal Generation Cost Difference We measure the marginal generation cost difference between the clearing unit and the adjacent unit in the merit order as:

$$\Delta C_{th}^{\text{diff}} = C_{i+1,th} - C_{i,th}, \tag{5.1}$$

where $C_{i,th}$ is the generation cost per kWh of the clearing generator i and $C_{i+1,th}$ is the cost of the generator immediately behind it in the merit order on day t and hour h.[15] To focus on strategic interaction rather than intra-group coordination, we restrict attention to cases in which generator $i+1$ belongs to a different power generation group than generator i.[16]

Marginal Carbon Cost The marginal carbon cost of the adjacent generator is computed from its fuel consumption, the benchmark, and the carbon price as:

$$CC_{i+1,th} = \lambda_t \left(\alpha \, ec_{i+1,th} - B \right), \tag{5.2}$$

where $CC_{i+1,th}$ is the marginal carbon cost for generator $i+1$, λ_t is the daily carbon price, and B is the emission intensity benchmark. The parameter α is the carbon emission factor, defined as kilograms of CO_2 emitted per kilogram of standard coal equivalent.[17] The term $ec_{i+1,th}$ denotes the heat rate (coal consumption per kWh) of generator $i+1$.

Generation Cost Difference vs. Carbon Cost Figure 9 reports the comparison between marginal generation cost differences and marginal carbon costs. The bars display the average generation cost difference at the 15-minute frequency, while the dashed line reports the corresponding average marginal carbon cost under the current benchmark. A positive marginal carbon cost indicates an implicit subsidy for the adjacent generator, whereas a negative value indicates that the generator is effectively taxed.

On average, marginal generation cost differences in Shandong, Shanxi, and Guangdong are about 0.73 cents/kWh, whereas the average marginal carbon cost in three provinces is approximately 0.56 cents/kWh. Since the subsidy (or tax) is smaller in magnitude than the generation cost difference, the adjacent generator cannot overturn the merit order by adjusting for the carbon cost. As a result, the clearing generator has little incentive to incorporate the carbon subsidy into its bid, and carbon cost pass-through is limited or absent.

Market power may further weaken pass-through. When the clearing generator and the nearby units belong to the same generation group, they may have scope to coordinate bids and

[15] For notational simplicity, we omit province subscripts in this section.

[16] See Appendix B for details on group classification and market power considerations.

[17] We use 2.493 kg-CO_2/kg-ce for coal-fired units and 1.6257 kg-CO_2/kg-ce for gas-fired units.

sustain higher clearing prices. In such cases, subsidies from the carbon market are more likely to be captured as additional rents rather than transmitted to electricity prices.

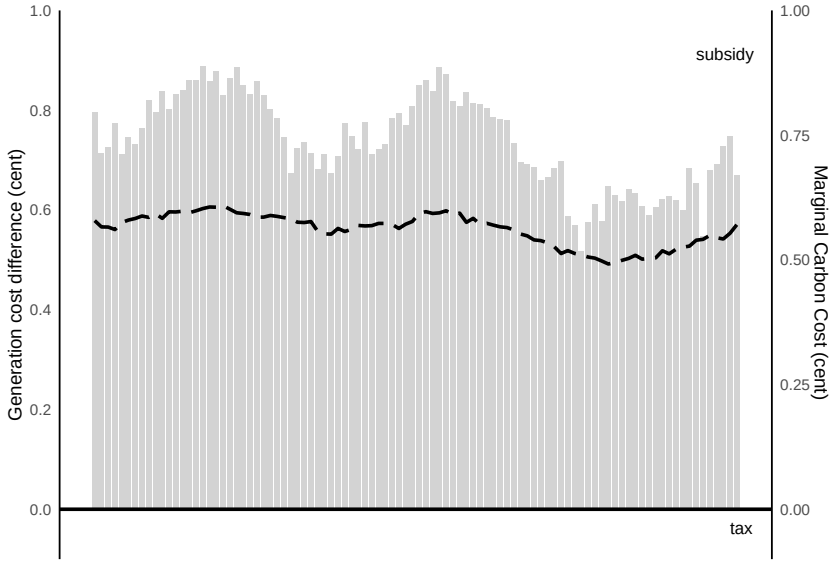


Figure 9: Generation Cost Difference and Marginal Carbon Cost under the Current Emission Intensity Benchmark.

Notes: Gray bars show average generation cost differences between the clearing unit and the adjacent unit in the merit order. The dashed line plots the average marginal carbon cost of the generator following the marginal unit.

5.2 Cost Pass-through from the Carbon to the Electricity Market

Section 5.1 shows that marginal generation cost differences exceed the effective "subsidy" from the carbon market, suggesting limited scope for carbon cost pass-through under the current market design. In this section, we directly estimate the pass-through rate in the existing electricity market in order to quantify how carbon costs affect spot electricity prices.

We estimate the pass-through rate using the following specification:

$$P_{jth} = \beta_1 C_{fuel,jth} + \beta_2 CC_{jth} + X_{jth}^{\text{Demand}} \beta^D + X_{jth}^{\text{Supply}} \beta^S + \theta_j + \lambda_{th} + \epsilon_{jth}, \tag{5.3}$$

where P_{jth} denotes the real-time market price in province j on day t and hour (or 15-minute interval) h. The term $C_{fuel,jth}$ is the fuel cost of the marginal generator, and CC_{jth} is its marginal carbon cost. The vectors X_{jth}^{Demand} and X_{jth}^{Supply} include controls for provincial total demand, renewable generation, and interprovincial electricity flows. Province fixed effects θ_j capture time-invariant regional heterogeneity, while time fixed effects λ_{th} (at the day–hour or day–15-minute level) flexibly absorb common shocks to the electricity market. The marginal fuel

and carbon cost variables $C_{fuel,jth}$ and CC_{jth} are constructed following the procedure described in Section 5.1.

5.2.1 Generation Cost and Carbon Cost of Marginal Generators

Generation Cost of the Marginal Generator The generation and carbon costs of marginal generators are central to measuring the magnitude of carbon cost pass-through in the spot market. Because fuel expenses account for the bulk of variable generation costs, we focus on fuel costs when constructing marginal generation costs. For each unit, we estimate fuel costs using unit-level fuel consumption data as:

$$C_{fuel,jth} = \begin{cases} p_t^{\text{Coal}} FC_{jth}, & \text{if the marginal unit is coal-fired,} \\ p_t^{\text{Gas}} FC_{jth}, & \text{if the marginal unit is gas-fired,} \end{cases} \tag{5.4}$$

where p_t^{Coal} and p_t^{Gas} are, respectively, the coal and gas prices on day t, and FC_{jth} is the fuel consumption per kWh of the marginal generator in province j on day t and hour (15-minute interval) h.

Carbon Cost of the Marginal Generator Given the identified marginal unit, we calculate its marginal carbon cost using:

$$CC_{jth} = \lambda_t \big(ec_{jth}\alpha - B \big), \tag{5.5}$$

where CC_{jth} is the carbon cost of the marginal generator in province j on day t and hour h; λ_t is the daily carbon price; ec_{jth} is the standard coal consumption (heat rate) of the marginal generator; α is the carbon emission factor in kg CO_2 per kg of standard coal equivalent (2.493 kg CO_2/kg ce for coal-fired units, and analogously defined for gas-fired units where applicable); and B denotes the relevant emission intensity benchmark.

5.3 Pass-through Rate Estimation

Table 3 reports the estimates from Equation (5.3) using both hourly and 15-minute data. Unlike earlier studies of carbon cost pass-through in European markets (Fabra and Reguant, 2014; Hintermann, 2016), our setting features (i) a rapidly rising share of renewables and associated intermittency (Jha and Leslie, 2025; Weber and Woerman, 2024), and (ii) a high coverage of medium- and long-term contracts for thermal generation.[18] Under these conditions, thermal

[18]Central government guidelines require that more than 85% of thermal generation be covered by medium- and long-term contracts in order to stabilize electricity prices.

units can exercise market power over the residual demand: during hours with high renewable output and low residual demand, they may submit very low bids, depressing prices, whereas during low-renewable periods they can bid at high prices, generating extreme price spikes. Such behavior can distort pass-through estimates if not addressed.

To mitigate these issues, we exclude extremely low prices (below the estimated marginal fuel cost from Section 5.1) and extremely high prices (top 10% of the price distribution) from the sample. Columns (1)–(4) in Table 3 present the baseline results. Across specifications, the estimated pass-through rate for fuel costs is close to one, ranging from 0.99 to 1.21, and the confidence intervals for the fuel cost coefficient always include 1 but exclude 0. This indicates that marginal fuel costs are almost fully passed through to real-time electricity prices. By contrast, the coefficients on carbon costs are small, statistically insignificant, and imprecisely estimated, with confidence intervals that span both positive and negative values and always include 0. This pattern suggests that, in the current institutional setting, marginal carbon costs are not systematically reflected in spot prices.

Table 3 thus implies that China's current rate-based carbon market has little discernible effect on spot electricity prices. While the carbon and electricity markets are formally linked through the allowance price, the impact of carbon pricing appears confined to the power sector's internal cost structure rather than transmitted to the broader economy via electricity prices. Consistent with the theoretical discussion in Section 3, the main effect of carbon trading under the present design is to reallocate profits: low-emission generators gain at the expense of high-emission ones, but the overall merit-order based dispatch remains largely unchanged. As a result, the ETS reinforces existing efficiency improvements rather than driving additional emission reductions at the margin.

We further explore cross-provincial heterogeneity in pass-through using Equation (5.3), estimated separately for each province while controlling for time fixed effects and the full set of covariates. The results are reported in Table 4. Shanxi's electricity market appears most efficient in terms of cost pass-through, with fuel cost coefficients close to one. By contrast, Shandong exhibits much lower pass-through, with only around 20–25% of fuel costs reflected in market prices. Guangdong lies between these two extremes. Importantly, across all three provinces, the estimated carbon cost coefficients remain statistically insignificant and far from full pass-through.

We conduct several robustness checks on the baseline estimates in Table 3. First, we allow for lagged cost effects by including 2-day, 5-day, and 10-day lags of fuel and carbon costs.

Table 3: Results of Pass-through Rate Estimation

	Hourly Results		Minute Results	
	(1)	(2)	(3)	(4)
Carbon	0.020	0.691	0.056	−0.035
	(0.664)	(0.596)	(0.276)	(0.254)
Fuel	1.141***	1.207***	0.997***	0.988***
	(0.093)	(0.135)	(0.042)	(0.062)
Renewables	−0.008***	−0.008***	−0.008***	−0.008***
	(0.0002)	(0.0003)	(0.0001)	(0.0001)
Load	0.004***	0.003***	0.004***	0.004***
	(0.0001)	(0.0002)	(0.0001)	(0.0001)
Transmission	−0.002***	−0.002***	−0.002***	−0.002***
	(0.0002)	(0.0002)	(0.0001)	(0.0001)
Indi-FE	N	Y	N	Y
Time-FE	Y	Y	Y	Y
Adjusted R^2	0.362	0.362	0.357	0.357

Note: The dependent variable is the real-time price in Shandong, Shanxi, and Guangdong. Marginal fuel and carbon costs are constructed by matching the marginal generator based on total demand and renewable output. Load, transmission, and renewable generation are included as controls. Robust standard errors are reported. For statistical significance, $^{*}p < 0.1$, $^{**}p < 0.05$, and $^{***}p < 0.01$.

Across these specifications, fuel cost pass-through remains positive and close to one, whereas carbon cost coefficients remain unstable and statistically insignificant (see Appendix C). Second, because true plant-level fuel procurement costs are unobserved, we re-estimate the models using alternative coal price series, including prices at Guangzhou Harbor, Datong, and Zaozhuang. The results are very similar, reinforcing the conclusion that marginal fuel costs are largely passed through to electricity prices, while carbon costs are not (see Appendix C).

5.4 Correlation between Carbon Costs and Electricity Prices

We next examine whether carbon costs are correlated with electricity prices at different time frequencies, starting from the daily level. Because carbon prices are often viewed as a medium- to long-run signal in the energy sector, daily regressions provide an intuitive benchmark for assessing their impact on power prices. Our baseline daily regression model is:

$$P_{jt} = \beta_1 p_t^{Carbon} + \beta_2 p_t^{Coal} + \beta_3 p_t^{Gas} + X_{jt}^{Demand}\beta^D + X_{jt}^{Supply}\beta^S + \theta_j + \lambda_t + \epsilon_{jt}, \tag{5.6}$$

Table 4: Pass-through Rates by Province

	Hourly Results			Minute Results		
	Shandong	Shanxi	Guangdong	Shandong	Shanxi	Guangdong
Carbon	−0.958	−0.472	4.147	−0.814	−0.497	1.195
	(1.918)	(1.150)	(1.284)	(1.145)	(0.566)	(0.550)
Fuel	0.256**	1.035**	0.645***	0.236***	1.037**	0.610***
	(0.026)	(0.168)	(0.0004)	(0.013)	(0.166)	(0.004)
Renewables	−0.010***	−0.017***	−0.006	−0.009***	−0.016***	−0.006
	(0.0004)	(0.001)	(0.002)	(0.0002)	(0.0003)	(0.002)
Load	0.010**	0.004*	0.003**	0.010**	0.004*	0.003*
	(0.001)	(0.001)	(0.0002)	(0.001)	(0.001)	(0.0003)
Transmission	−0.013	−0.013*	−0.001	−0.013	−0.012*	−0.001
	(0.005)	(0.003)	(0.001)	(0.005)	(0.003)	(0.001)
Time-FE	Y	Y	Y	Y	Y	Y
Observations	9,485	7,940	5,647	33,754	26,742	22,290
Adjusted R^2	0.390	0.628	0.604	0.373	0.617	0.601

Note: The dependent variable is the real-time price in Shandong, Shanxi, and Guangdong, estimated separately by province. Load, transmission, and renewable generation are included as controls. Robust standard errors are reported. For statistical significance, *$p < 0.1$, **$p < 0.05$, and ***$p < 0.01$.

where P_{jt} denotes the average real-time electricity price in province j on day t; p_t^{Coal}, p_t^{Gas}, and p_t^{Carbon} are the daily coal, gas, and carbon allowance prices, respectively, and β_1, β_2, β_3 capture their correlations with electricity prices. The vectors X_{jt}^{Demand} and X_{jt}^{Supply} include demand- and supply-side controls, respectively. Consistent with Equation (5.3), we control for total load, net interprovincial transmission, and renewable generation. Province fixed effects θ_j and time fixed effects λ_t are also included.[19]

Table 5 presents the estimation results from Equation (5.6) for both daily and hourly data. Columns progressively add demand and supply controls as well as province fixed effects to assess robustness. The results are consistent with those in Table 3. Coal prices are positively and significantly associated with electricity prices across specifications, with coefficients that are stable in magnitude once controls are included. Demand- and supply-side variables also have the expected signs: higher load is associated with higher prices, while greater renewable generation

[19]Because the carbon, gas, and coal prices are observed at the national, daily level, we include a rich set of time fixed effects: year, month-of-year, day-of-month, and hour-of-day.

Table 5: Correlation between Carbon Prices and Electricity Prices

	Daily Results			Hourly Results		
Carbon Price	−1.691	−1.160	−1.039	−1.312	−3.950	−0.429
	(2.313)	(2.004)	(1.779)	(2.807)	(3.321)	(2.359)
Coal Price	0.210***	0.235***	0.225**	0.210***	0.149**	0.257**
	(0.051)	(0.042)	(0.035)	(0.039)	(0.075)	(0.043)
Gas Price	0.065	0.267	0.150	0.452**	−1.120	0.642
	(0.281)	(0.337)	(0.284)	(0.194)	(1.097)	(0.332)
Load		0.003***	0.003**		0.006***	0.005*
		(0.0005)	(0.001)		(0.001)	(0.002)
Renewables		−0.003	−0.007		−0.006***	−0.010*
		(0.003)	(0.004)		(0.002)	(0.003)
Transmission		−0.003***	−0.002		−0.006**	−0.003
		(0.001)	(0.001)		(0.002)	(0.002)
Individual FE	N	N	Y	N	N	Y
Time FE	Y	Y	Y	Y	Y	Y
Observations	1,601	1,601	1,601	23,072	23,072	23,072
Adjusted R^2	0.396	0.484	0.516	0.255	0.450	0.465

Note: The dependent variable is the average real-time price in Shandong, Shanxi, and Guangdong. We sequentially add control variables (load, renewables, transmission) and fixed effects. Robust standard errors are reported. For statistical significance, *$p < 0.1$, **$p < 0.05$, and ***$p < 0.01$.

tends to reduce prices by displacing coal-fired generation and lowering marginal costs. Net exports (positive transmission) are generally associated with lower local prices, consistent with market integration effects.

By contrast, the coefficients on the carbon price are negative and statistically insignificant in all specifications. This pattern is consistent with our theoretical predictions and the pass-through regressions in Table 3. Under the current rate-based ETS design, low-emission, high-efficiency generators receive implicit subsidies that reduce their effective marginal costs, yet they do not systematically pass these cost reductions on to final electricity prices. As a result, the estimated relationship between carbon prices and electricity prices is slightly negative but economically small and statistically indistinguishable from zero.

6 Discussion

The empirical results show that carbon costs are not effectively transmitted to electricity prices. This section discusses the mechanisms behind this missing carbon pass-through and its political economy implications. We address three interrelated questions: what explains the lack of carbon cost pass-through in China's electricity–carbon market, who actually benefits under the current rate-based design, and under what conditions carbon costs would start to be reflected in electricity prices.

6.1 What Causes the Missing Carbon Pass-through?

6.1.1 Regulatory Capture in Pilot Carbon Markets

In a textbook rate-based ETS, sufficiently tight benchmarks and credible enforcement should raise the marginal cost of emission-intensive generators and, in turn, create scope for carbon cost pass-through to electricity prices. Our theoretical model shows that, when the benchmark is loose and many generators receive net subsidies rather than taxes, this mechanism weakens: the ETS primarily redistributes rents within the power sector instead of changing the merit order or affecting prices. The empirical finding of negligible carbon cost pass-through therefore raises a natural question: why are benchmarks in China's system so lenient, and why do they appear to favor particular types of firms?

To shed light on this question, we first examine how regulatory stringency differed across sectors in the regional pilot ETSs. Using official policy documents, we compare the tightening of emission ceilings in power, cement, steel, and other heavy industries relative to a 2015–2017 baseline. Figure 10 shows that the power sector experienced much weaker tightening of emission caps than cement and steel, even though it accounts for the largest share of CO_2 emissions. Sectors with a higher share of state-owned enterprises also tend to face less stringent caps.[20] We document a strong negative correlation between the stringency of sectoral benchmarks and the share of SOEs within a sector, conditional on province and year. This pattern is consistent with, though not a formal proof of, regulatory capture in benchmark design.

From a political economy perspective, this evidence aligns with classic theories of regulation that emphasize the influence of large, politically connected firms on regulatory outcomes (Peltzman, 1976; Stigler, 1984). In China's case, sectors dominated by SOEs have both stronger

[20] Appendix D provides additional evidence by relating sectoral cap tightening to the share of SOEs within sectors at the provincial level.

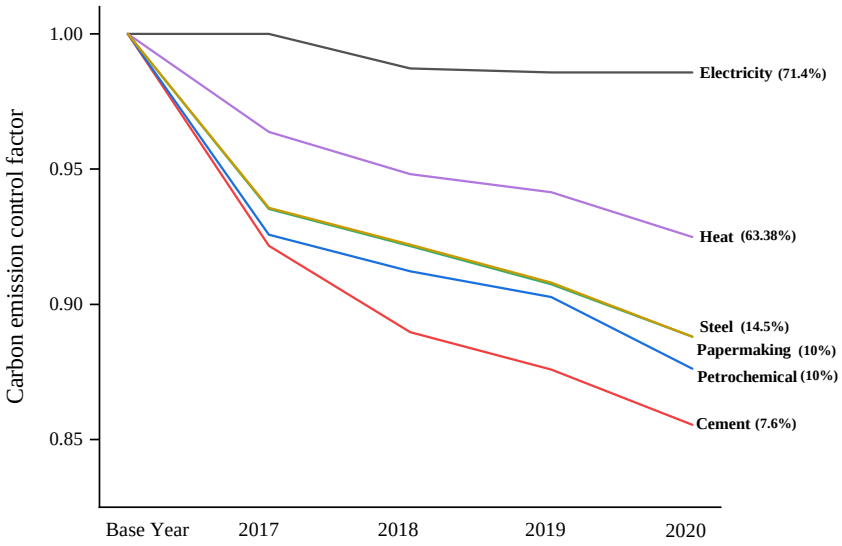


Figure 10: Trends of Carbon Regulation Intensity in Different Industries.

Notes: The curves show sectoral emission ceilings from 2017 to 2020 relative to the average cap over 2015–2017, based on regional pilot ETS documents. Numbers in brackets report the share of state-owned firms in each sector, calculated from the 2015 Chinese Industrial Enterprise Database.

incentives and greater capacity to shape benchmark setting and compliance rules in ways that protect their interests. The reduced-form correlations in Figure 10 do not, by themselves, establish causality, but together with the ownership-specific patterns in the national ETS documented below, they point toward a systematic alignment of carbon policy design with the preferences of state-owned incumbents rather than with purely environmental or efficiency objectives.

Figure 11 further illustrates the relationship between market power and regulatory stringency in the pilot markets. The horizontal axis plots the share of generation controlled by the major power groups (a proxy for market power), and the vertical axis shows the share of generation from units that are effectively penalized by the benchmark. Regions with higher SOE dominance tend to have a smaller share of penalized generation, suggesting that areas where the major groups are stronger politically also face looser benchmarks and weaker enforcement.

6.1.2 Regulatory Capture in the National ETS

We next examine how regulatory capture manifests in the national ETS. Using data from the *Compilation of Electric Power Industry Statistical Data*, we identify units that are penalized under the national carbon market and classify them into the five major power groups and all other (non-five) groups. Table 6 summarizes the number and capacity of penalized units from 2021 to 2024. The patterns are striking: only about 2–5% of units belonging to the five major groups are penalized, compared with 19–23% of units outside the five major groups. A similar

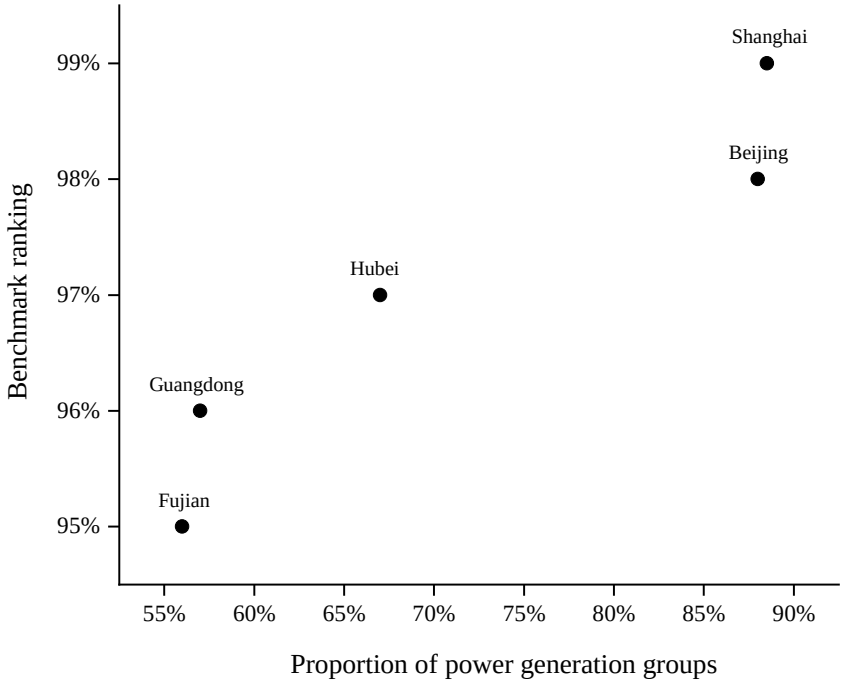


Figure 11: Market Power and Benchmark Stringency in Pilot Carbon Markets.

Notes: The x-axis shows the share of generation by the major state-owned power groups in each region. The y-axis shows the share of generation from units whose emission intensity exceeds the sectoral benchmark.

asymmetry arises for capacity: penalized capacity shares for non-five groups are several times higher than those for the five groups.

Table 6: Number and Capacity of Penalized Units by Ownership Group

		2021	2022	2023	2024
Number of penalized units					
	Five groups	46 (2%)	51 (2%)	74 (4%)	92 (5%)
	Non-five groups	364 (19%)	371 (20%)	409 (22%)	431 (23%)
Penalized capacity (MW)					
	Five groups	35,061 (3%)	40,521 (4%)	60,719 (5%)	73,522 (7%)
	Non-five groups	81,052 (7%)	86,060 (8%)	118,324 (11%)	129,883 (12%)

Note: Numbers in parentheses denote the share of penalized units or capacity for each ownership group.

The asymmetry in penalization rates between the five major power groups and other owners, documented in Table 6, does not by itself prove regulatory capture. Units owned by the five groups are, on average, larger and more efficient than those operated by other firms, so a lower fraction of them exceeding any given intensity benchmark is to be expected under a purely technology-based rule. A neutral benchmark that reflects underlying efficiency differences would

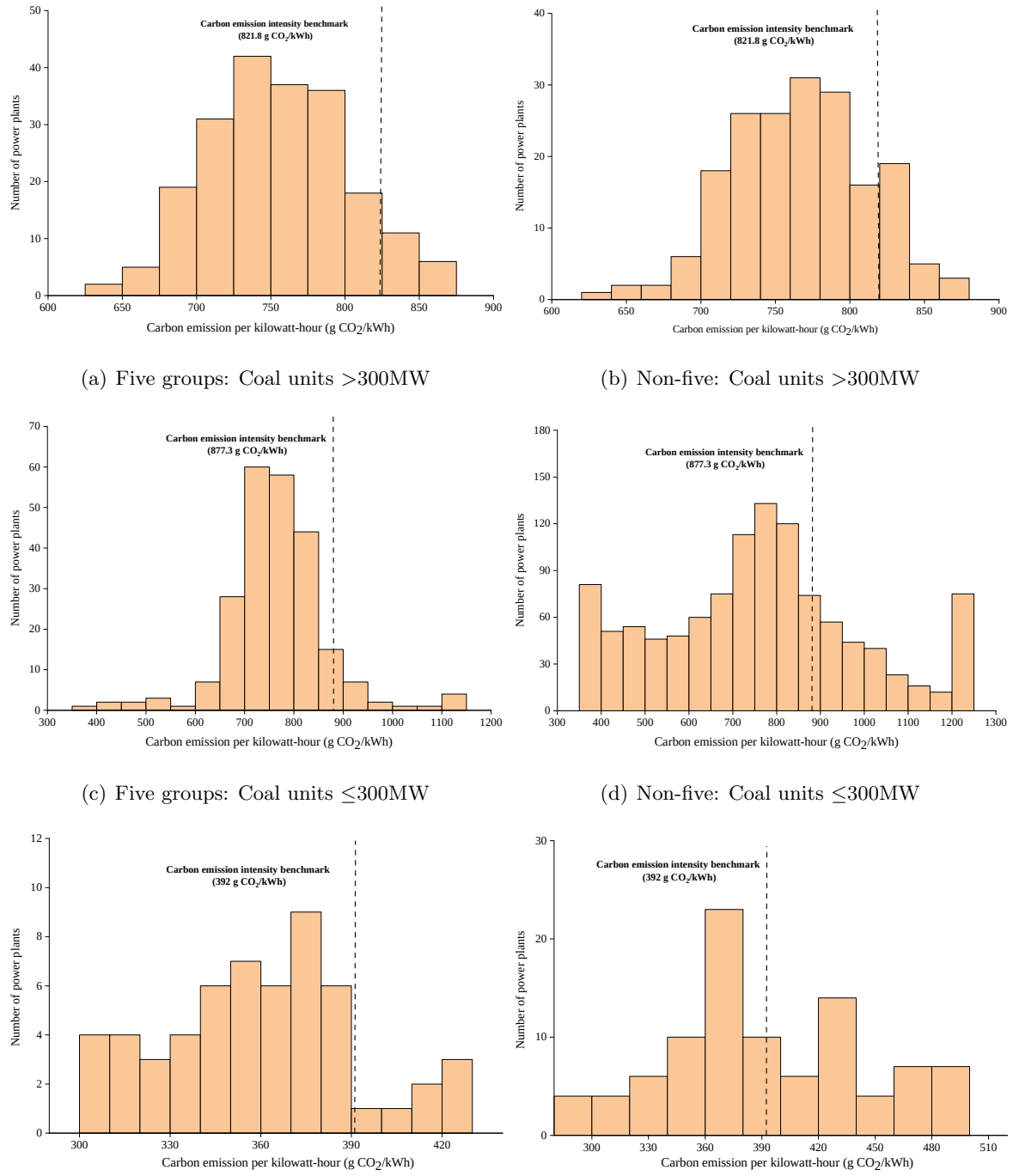
therefore naturally imply some gap in penalization rates across ownership types.

However, both the magnitude and the shape of the penalization pattern are difficult to reconcile with efficiency considerations alone. Even after conditioning on unit size and fuel type, only about 2–5% of units owned by the five groups are penalized, compared with roughly 19–23% of units outside the five groups, and the share of penalized capacity is several times higher for non-five units than for the five groups. Figure 12 provides additional structure: panels (a), (c), and (e) show that, for coal and gas units owned by the five major groups, the official benchmarks lie just to the right of the main mass of the emission-intensity distributions (especially for the larger coal units and gas units). A modest tightening of the benchmark would move the vertical line leftward into the bulk of the distribution, instantly bringing a large number of five-group units into non-compliance. The current benchmark values therefore sit precisely at the point where almost all five-group units remain on the "safe" side of the threshold.

By contrast, panels (b), (d), and (f) in Figure 12 show no comparable bunching pattern for non-five units. Their emission-intensity distributions are more dispersed around the benchmark, with a sizable number of units located on both sides of the vertical line rather than clustering just below it. In other words, benchmarks appear to be chosen so that they tightly hug the right tail of the five-group distributions, while cutting more deeply into the distributions of other owners.

Taken together, these patterns suggest that benchmark levels and enforcement practices are more closely aligned with the cost structures of the dominant state-owned groups than would be implied by a neutral, purely efficiency-driven rule. We interpret this as suggestive—though not definitive causal—evidence of regulatory capture in the national ETS. In combination with the sectoral evidence from the pilot ETSs, where sectors with higher SOE shares face systematically looser caps, the ownership-specific bunching around benchmarks points to a carbon market design that systematically protects large state-owned incumbents.

Finally, we compare emission and emission-intensity trends between provinces with and without competitive electricity markets, before and after the launch of the national ETS. Using the *Compilation of Electric Power Industry Statistical Data*, Figure 13 plots total emissions and average emission intensity for (i) all thermal units nationwide, (ii) provinces without spot markets (covered only by carbon trading), and (iii) provinces with both electricity and carbon markets (Shandong, Shanxi, Guangdong). Emission intensity declines more steeply in provinces with electricity markets, while it remains almost unchanged in non-spot provinces and at the



(a) Five groups: Coal units >300MW

(b) Non-five: Coal units >300MW

(c) Five groups: Coal units ≤300MW

(d) Non-five: Coal units ≤300MW

(e) Five groups: Gas units

(f) Non-five: Gas units

Figure 12: Emission Intensity Distributions and Benchmarks by Ownership Group.

Notes: The x-axis is unit-level emission intensity (gCO_2/kWh); the y-axis is the number of units. Vertical lines indicate benchmark values. Statistics use 2021 power plant data and the 2021–2022 benchmark rules.

national average. At the same time, total emissions in electricity-market provinces increase, reflecting scale effects from more efficient dispatch. Taken together, these patterns suggest that recent efficiency gains have been driven primarily by electricity market reforms rather than by the national ETS itself. The carbon market, given its loose benchmarks and limited

pass-through, has so far had only a modest impact on the power system.

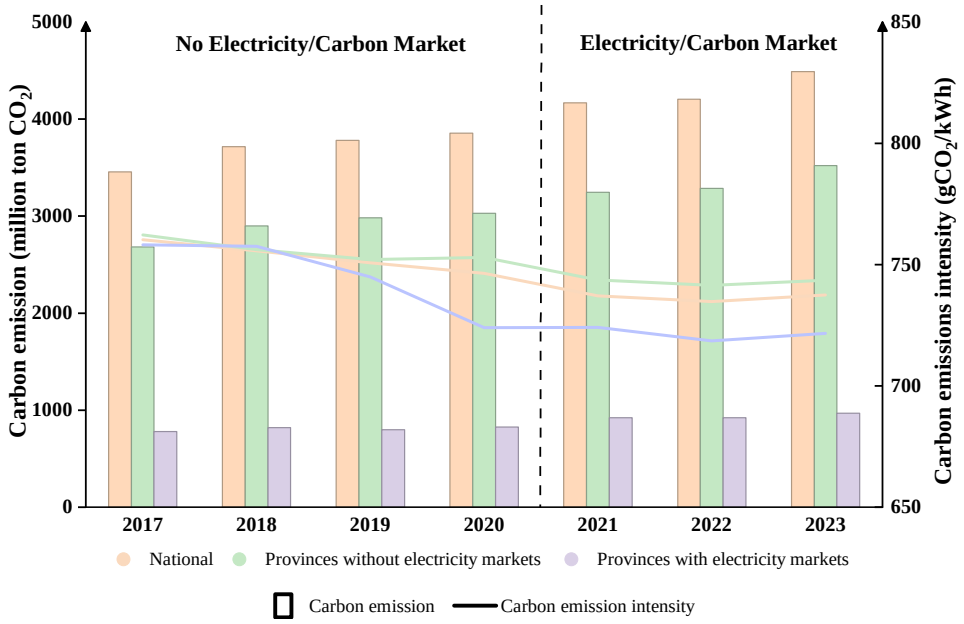


Figure 13: Trends in Carbon Emissions and Emission Intensity.

Notes: Bars show annual total CO_2 emissions from thermal units. Solid lines show average emission intensity for the national sample, provinces without spot markets, and provinces with both spot and carbon markets.

6.2 Who Benefits from the Carbon Market?

The rate-based ETS in China creates implicit carbon assets or liabilities for generators depending on their emission intensity relative to the benchmark. To quantify the incidence of these transfers, we calculate unit-level carbon costs using annual weighted-average carbon prices, benchmark rules, unit-level fuel consumption, and generation. Aggregating by province, ownership, and unit size yields the patterns reported in Tables 7 and 8.

Table 7 shows that the total carbon cost in all three provinces is negative over 2021–2023, indicating that the ETS has operated as a net subsidy scheme for thermal power units.[21] For coal units above 300 MW, total subsidies received by units owned by the five major power groups are substantially larger in absolute terms than those received by non-five units. When we examine average carbon costs per unit (Table 8), the same pattern emerges: the five major groups receive larger average subsidies per unit than other owners, even though non-five groups own more small units and, in some cases, more carbon-intensive plants.

Overall, the ETS operates as a sizable intra-sectoral transfer scheme, with large and relatively efficient state-owned units receiving sizeable net subsidies, especially for coal units above

[21] Appendix F reports the share of units receiving net subsidies in each province and year.

Table 7: Provincial Total Carbon Cost (million CNY)

	Province	2021	2022	2023
Shandong				
>300MW	Five groups	-902.55	-1001.15	-1086.43
	Non-five groups	-443.51	-492.43	-534.40
≤300MW	Five groups	-638.56	-709.13	-515.83
	Non-five groups	-1352.83	-1505.47	-1129.13
Shanxi				
>300MW	Five groups	-144.06	-190.69	-217.04
	Non-five groups	-96.44	-124.51	-141.52
≤300MW	Five groups	-248.16	-349.88	-241.33
	Non-five groups	-319.36	-436.74	-145.41
Guangdong				
>300MW	Five groups	-487.06	-603.49	-686.93
	Non-five groups	-478.84	-579.51	-658.83
≤300MW	Five groups	-76.48	-94.89	-66.82
	Non-five groups	-181.28	-212.64	-8.72
Gas-fired units	Five groups	-15.98	-19.15	18.89
	Non-five groups	-33.12	-37.11	114.12

Note: Negative values indicate net subsidies; positive values indicate net carbon taxes.

300 MW. Smaller and non-five units receive smaller average subsidies and are more likely to be penalized. These distributional patterns are hard to reconcile with a neutral or purely efficiency-based benchmark and are instead consistent with the regulatory capture mechanism outlined above.

6.3 When Will Carbon Cost Pass-through Occur?

The previous sections show that under the current benchmark rules, most units—especially those owned by the five major groups—receive subsidies, and carbon cost pass-through to electricity prices is negligible. We now ask under what conditions carbon costs would start to be reflected in power prices. To address this question, we simulate the effect of tightening emission intensity benchmarks on the carbon cost of marginal and near-marginal units.

Table 8: Provincial Average Carbon Cost per Unit (million CNY)

	Province	2021	2022	2023
Shandong				
>300MW	Five groups	-22.01	-24.42	-26.50
	Non-five groups	-20.16	-22.38	-24.29
≤300MW	Five groups	-7.61	-8.44	-6.14
	Non-five groups	-3.37	-3.74	-2.81
Shanxi				
>300MW	Five groups	-5.15	-6.81	-7.75
	Non-five groups	-4.19	-5.41	-6.15
≤300MW	Five groups	-6.89	-9.72	-6.70
	Non-five groups	-3.67	-5.02	-1.67
Guangdong				
>300MW	Five groups	-22.14	-27.43	-31.22
	Non-five groups	-11.40	-13.80	-15.69
≤300MW	Five groups	-9.56	-11.86	-8.35
	Non-five groups	-3.07	-3.60	-0.15
Gas-fired units	Five groups	-1.99	-2.39	2.36
	Non-five groups	-0.81	-0.91	2.78

Note: Negative values indicate net subsidies; positive values indicate net carbon taxes.

6.3.1 Benchmarks and the Onset of Pass-through

We gradually tighten the emission intensity benchmarks for coal units above 300 MW, coal units below 300 MW, and gas units, and recompute the marginal carbon cost received by units immediately behind the clearing generator.[22] Figure 14 shows that as benchmarks become more stringent, the marginal carbon cost received by the adjacent unit declines and eventually changes sign from subsidy to tax. Table 9 summarizes the benchmark levels at which this transition occurs. When benchmarks tighten to about 0.71 tCO_2/MWh for large coal units, 0.80 tCO_2/MWh for small coal units, and 0.33 tCO_2/MWh for gas units, the adjacent unit no longer receives a subsidy on average and starts paying a tax.

[22]Appendix G details how we recalculate the carbon price under alternative benchmark schedules.

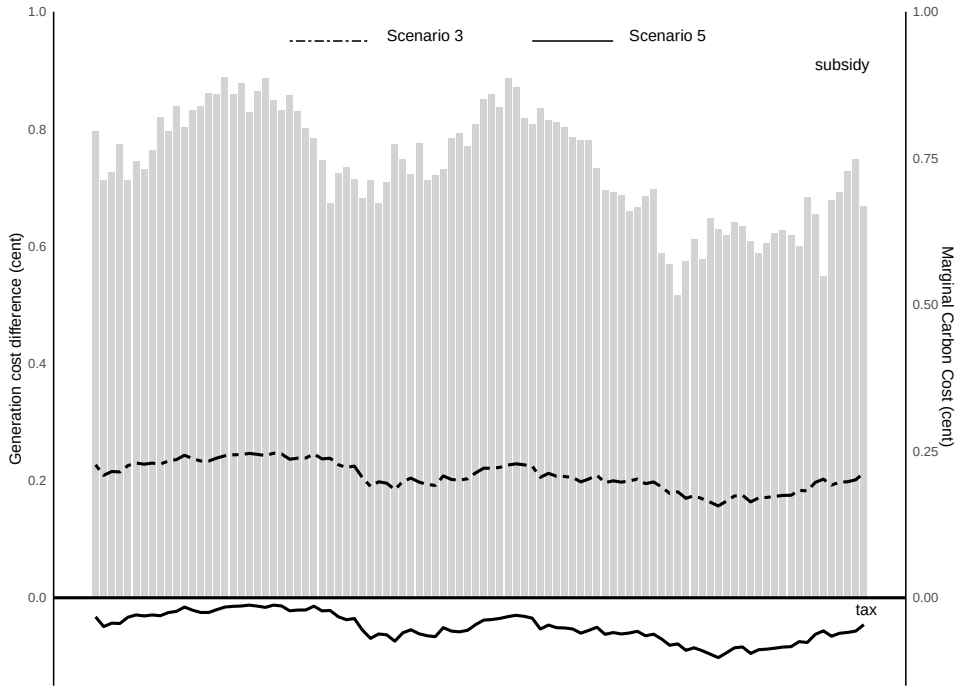


Figure 14: Generation Cost Difference and Marginal Carbon Cost under Tighter Benchmarks.

Notes: Gray bars show the generation cost differences between the marginal unit and the next unit. The dotted and solid lines show the marginal carbon cost of the adjacent unit under different benchmark levels. Positive values indicate subsidies; negative values indicate taxes.

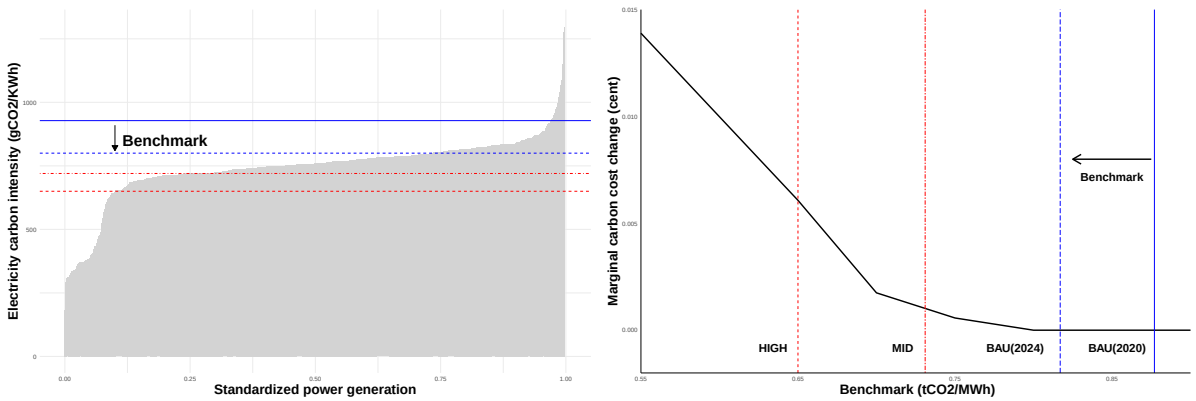
Table 9: Subsidies or Taxes under Alternative Benchmarks (tCO_2/MWh)

Scenario	Coal >300	Coal ≤300	Gas	Carbon cost
1	0.80	0.88	0.37	subsidy
2	0.77	0.86	0.36	subsidy
3	0.75	0.84	0.35	subsidy
4	0.73	0.82	0.34	subsidy
5	0.71	0.80	0.33	tax

Note: We gradually tighten emission intensity benchmarks until the average marginal carbon cost of the unit after the marginal generator becomes negative (i.e., it pays a tax rather than receiving a subsidy), corresponding to the solid line in Figure 14.

6.3.2 Benchmark Tightening and Marginal Carbon Costs

Figure 15 provides a more detailed view of how marginal carbon costs evolve as benchmarks tighten. Panels (a) shows ordered carbon intensities for generators owned by the five major groups and by other owners, with bars weighted by standardized annual output. Most units, particularly those owned by the five major groups, currently lie below the official benchmark,



(a) Benchmark and penalized generators

(b) Marginal carbon cost change

Figure 15: Ordered Carbon Intensity and Marginal Carbon Cost under Alternative Benchmarks.

Notes: Panel (a) shows ordered emission intensities with bar width equal to standardized annual output in 2021. Dashed and dotted lines indicate four benchmark levels (high, medium, BAU 2024, BAU 2020), corresponding to the scenarios in panel (b). Panel (b) plots the average marginal carbon cost change as a function of emission intensity under these benchmark levels.

implying that they receive subsidies rather than taxes. Under such loose benchmarks, carbon costs cannot be easily added to electricity prices.

Panel (b) of Figure 15 plots the average marginal carbon cost change for different benchmark levels. When benchmarks exceed about 0.8 tCO_2/MWh, nearly all generators receive subsidies, and the magnitude of those subsidies is smaller than the underlying generation cost differences. In this range, carbon cost pass-through is effectively absent because the ETS merely reinforces the existing merit order. As benchmarks tighten into the 0.65–0.8 tCO_2/MWh range, some marginal units begin to pay taxes rather than receive subsidies, but the resulting marginal carbon cost—on the order of 0.005 cents/kWh—is still only a small fraction of the marginal generation cost. Generators thus have little incentive to adjust their bidding strategies.

Once benchmarks are tightened below roughly 0.6 tCO_2/MWh, marginal carbon costs increase more sharply and become economically significant relative to marginal generation cost differences. In this regime, it becomes more likely that generators will internalize carbon costs in their bids, and genuine carbon cost pass-through to electricity prices could emerge. In other words, for carbon pricing to meaningfully affect electricity prices—and thereby downstream sectors—China would need both to tighten benchmarks substantially and to address the regulatory capture that currently keeps benchmarks aligned with the performance and interests of the dominant state-owned power groups.

7 Conclusion

This paper examined how China's national, rate-based emissions trading system (ETS) affects power generators, electricity prices, and emissions in the world's largest carbon-emitting economy. Unlike cap-and-trade systems such as the EU ETS, China's tradable performance standard allocates allowances based on emission intensity benchmarks, so firms are effectively taxed or subsidized relative to these standards rather than facing a uniform price on all emissions. This institutional design raises the question of whether lessons from cap-and-trade markets carry over to China's system and whether its ETS can generate a meaningful carbon price signal in the electricity sector, which currently accounts for a large share of national CO_2 emissions.

From a theoretical perspective, we develop a model of profit-maximizing generators operating in coupled electricity and carbon markets under both cap-and-trade and rate-based designs. Under a standard cap-and-trade scheme, all inframarginal generators face a positive marginal carbon cost, so carbon prices tend to be fully or nearly fully passed through into electricity prices when demand is inelastic. In contrast, under a rate-based scheme with loose benchmarks, generators experience heterogeneous cost impacts: relatively clean units receive implicit subsidies, while dirtier units pay taxes, and the merit order of marginal generation costs is unchanged. The rate-based ETS therefore rotates the supply curve and redistributes profits within the sector without necessarily raising prices or reducing aggregate emissions, and the combination of low carbon prices and small, heterogeneous subsidies gives generators an incentive to keep carbon rents rather than pass them through to electricity prices.

The empirical analysis uses high-frequency price data and unit-level information from three provinces with competitive electricity markets—Shandong, Shanxi, and Guangdong—to test the model's predictions. Comparing marginal fuel cost differences with marginal carbon subsidies or taxes for adjacent units shows that, in most periods, carbon payments are too small to overturn the bidding order, so clearing generators can retain subsidies without changing their bids. Regression estimates of cost pass-through confirm that fuel costs are almost fully reflected in real-time prices, whereas the pass-through of carbon costs is statistically indistinguishable from zero at both 15-minute and daily frequencies. Additional correlation analysis also finds no robust relationship between national carbon prices and provincial electricity prices once fuel costs, demand, renewable output, and interprovincial transmission are controlled for.

We then investigate the distributional and political economy implications of China's rate-based ETS. Aggregating unit-level carbon payments shows that the system operates as a net

subsidy scheme for thermal generators in all three provinces, with particularly large transfers to large coal units owned by the five major state-owned power groups. While these units are on average more efficient, penalization rates and benchmark placement suggest that efficiency alone cannot account for the observed asymmetries: only a small share of units owned by the five groups are penalized, compared with a much higher share of units owned by other firms, and the emission-intensity distributions of five-group units bunch just to the left of the benchmark, whereas non-state units display no comparable bunching. Combined with sector-level evidence from pilot ETSs—where sectors with higher state-owned shares face systematically looser caps—these patterns are consistent with, though not a formal proof of, regulatory capture in benchmark design and implementation.

Simulation exercises further explore the conditions under which carbon costs would start to be transmitted to electricity prices. Tightening benchmarks gradually shows that only when coal and gas benchmarks are reduced by roughly 10–20% relative to current levels do marginal units begin to pay economically meaningful carbon taxes rather than receive small subsidies, and only then does the marginal carbon cost become comparable in magnitude to marginal fuel cost differences. In other words, effective carbon cost pass-through in China's power sector would require substantially stricter emission intensity benchmarks and, likely, higher allowance prices than those observed so far. At the same time, national data comparing provinces with and without electricity spot markets suggest that recent improvements in emission intensity are mainly driven by electricity market reforms rather than by the ETS, as emission intensity falls fastest in market-based provinces while national emissions and emissions in non-market provinces remain flat or increase.

From a policy perspective, the findings highlight both the strengths and limitations of China's current carbon market design. The rate-based ETS has successfully redirected profits toward more efficient generators, reinforcing the merit-order effect and supporting the expansion of high-efficiency and gas-fired units, but it has not yet created a strong, economy-wide carbon price signal. To move from intra-sectoral redistribution toward genuine decarbonization, policymakers would need to tighten benchmarks significantly, increase the share of allowances allocated through auctioning, expand coverage beyond the power sector, and coordinate ETS reforms with ongoing electricity market liberalization. Addressing the political economy forces that align benchmark design with the interests of dominant state-owned incumbents will be crucial for turning China's carbon market into an effective instrument for achieving its dual goals of peaking emissions before 2030 and reaching carbon neutrality by 2060.

Acknowledgement

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Appendix

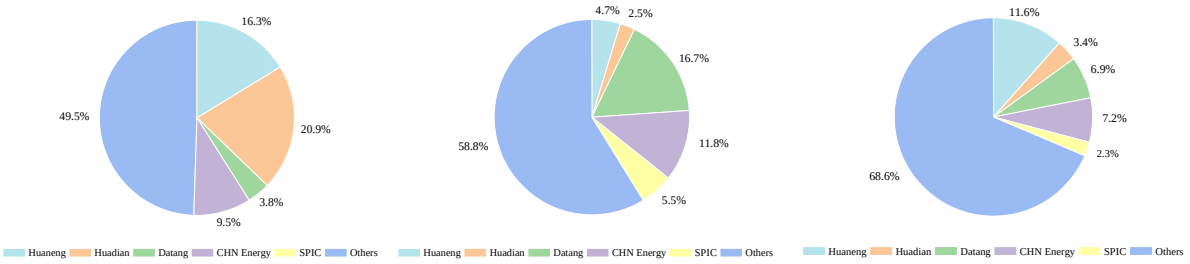
A Unit-level Data in Shandong, Shanxi, and Guangdong

The primary data sources are the *"Compilation of Statistics on the Electric Power Industry"* and the *"National Unit Energy Efficiency Competition Data"*, both of which are annually published by the *"China Electricity Council"*.

The Compilation data provides firm-level information, including details such as installed capacity, electricity production, coal consumption, and utilization hours for a given year. After filtering out power plants lacking data on installed capacity, coal consumption, and electricity production, we identified 314, 87, and 68 coal-fired power plants in Shandong, Shanxi, and Guangdong respectively. Meanwhile, the National Unit Energy Efficiency Competition Data offers unit-level data with matching information to the Compilation dataset. It should be noted that not all units participate in the competition, and unit-level data does not cover all power plants. To address this, we cross-referenced the firm-level and unit-level data. For power plants with unmatchable data and an installed capacity exceeding 300MW, we manually checked the unit mix using publicly available information. Ultimately, we constructed unit-level data, including installed capacity, electricity production, utilization hours, and coal consumption for power supply, comprising 478 units in Shandong, 180 units in Shanxi and 180 units in Guangdong.

B Power Generation Groups and Market Power

In China, the five largest power generation groups, which are Huaneng, Huadian, Datang, CHN Energy, and SPIC, have strong market power and occupy a large share of installed capacity in all three provinces, as shown in Figure A1. The installed capacity of the five major power generation groups accounts for approximately 30%-50% of the province's total installed capacity. Since generators within the same power generation group may engage in collusion when bidding, we set that the next generator, $i+1$ should be from another generation group.



(a) Shandong (b) Shanxi (c) Guangdong

Figure A1: Proportion of Installed Capacity of the Five Major Power Generation Groups in each Provinces

C Robustness Check

C.1 Lag Term Test

Table A1: Robustness Checks of Pass-through Rate Estimation with Different Lag Terms

	2-day Lag		5-day Lag		10-day Lag	
	Hourly	Minute	Hourly	Minute	Hourly	Minute
Carbon	0.709	-0.075	1.045	0.271	1.067	0.445
	(0.994)	(0.445)	(0.991)	(0.441)	(0.981)	(0.438)
Fuel	1.154***	0.953***	1.159***	0.964***	0.993***	0.811***
	(0.224)	(0.109)	(0.224)	(0.109)	(0.205)	(0.100)
Indi-FE	Y	Y	Y	Y	Y	Y
Time-FE	Y	Y	Y	Y	Y	Y

Note: The dependent variable is the real-time prices in Shandong, Shanxi, and Guangdong provinces. We estimated the cost by matching the marginal generator with 2-day, 5-day, and 10-day lags. The load, transmission, and renewable variables are also covered. Only hourly data is applied in Shandong province as it runs with market prices at an hourly frequency. Robust standard errors are reported. For statistical significance, $*p < 0.1$, $**p < 0.05$, and $***p < 0.01$.

C.2 Changing the Coal Costs

Table A2: Robustness Checks of Pass-through Rate Estimation Using Different Coal Prices

	Guangzhou Harbor			Datong			Zaozhuang		
	Shandong	Shanxi	Guangdong	Shandong	Shanxi	Guangdong	Shandong	Shanxi	Guangdong
Carbon	−0.431	−0.458	1.101	−0.835	−0.648	0.021	−0.436	0.120	1.729
	(0.946)	(0.778)	(0.522)	(1.077)	(0.454)	(0.937)	(1.028)	(0.901)	(0.517)
Fuel	0.151**	0.952**	0.624***	0.390**	1.180**	1.134	0.030	1.012***	0.443***
	(0.017)	(0.189)	(0.003)	(0.069)	(0.129)	(0.191)	(0.054)	(0.055)	(0.003)
Time-FE	Y	Y	Y	Y	Y	Y	Y	Y	Y
Observations	35,175	28,244	23,083	39,681	39,198	24,340	35,596	26,436	23,260
Adjusted R^2	0.380	0.594	0.596	0.419	0.531	0.610	0.367	0.564	0.576

Note: The dependent variable is the real-time prices in Shandong, Shanxi, and Guangdong provinces. We estimated the cost by matching the marginal generator with different coal prices from Guangzhou Harbor, Datong, and Zaozhaung. Additional shipping fees are added (20% to 30%). The load, transmission, and renewable variables are also covered. Only hourly data is applied in Shandong province as it runs with market prices at an hourly frequency. Robust standard errors are reported. For statistical significance, $*p < 0.1$, $**p < 0.05$, and $***p < 0.01$.

D Carbon emission constraint trends in different industries

Table A3: Carbon emission constraint trends in different industries

	Base Year	2017	2018	2019	2020	State-owned firms (%)
Beijing						
Power	1	1	0.95	0.95	0.95	88.16
	(936.30)	(936.30)	(886.40)	(886.40)	(886.40)	
Heat	1	0.98	0.97	0.97	0.97	78.95
Steel	1	0.9	0.87	0.86	0.82	34.48
Cement	1	0.8	0.72	0.69	0.66	30.49
Petrochemical	1	0.83	0.8	0.81	0.77	23.96
Papermaking	1	0.9	0.87	0.86	0.82	13
Shanghai						
Power	1	1	1	1	1	88.50
	(882.97)	(882.97)	(882.97)	(882.97)	(882.97)	
Heat	1	0.96	0.95	0.95	0.93	72.73
Steel	1	0.93	0.91	0.89	0.86	17.43
Cement	1	0.93	0.91	0.89	0.86	16.67
Petrochemical	1	0.93	0.91	0.89	0.86	12.24
Papermaking	1	0.93	0.91	0.89	0.86	3.45
Guangdong						
Power	1	1	0.99	0.99	0.99	56.70
	(891.88)	(891.88)	(882.38)	(882.38)	(882.38)	
Papermaking	1	1	1	1	1	5.84
Steel	1	1	1	1	1	5.25
Cement	1	1	1	1	1	3.82
Petrochemical	1	1	1	1	1	3.75
Hubei						
Power	1	1	1	1	1	66.94
	(783.91)	(783.91)	(783.91)	(783.91)	(783.91)	
Heat	1	0.95	0.92	0.91	0.88	38.46
Steel	1	0.96	0.95	0.93	0.91	9.76
Papermaking	1	0.97	0.95	0.94	0.92	8.43
Petrochemical	1	0.97	0.95	0.94	0.92	6.74
Cement	1	0.96	0.94	0.92	0.90	6.30
Fujian						
Power	1	1	1	0.99	0.99	56.49
	(897.20)	(897.20)	(897.20)	(890.29)	(890.29)	
Papermaking	1	0.88	0.88	0.85	0.83	9.09
Steel	1	0.88	0.88	0.85	0.84	5.48
Petrochemical	1	0.90	0.90	0.87	0.83	4.71

Note: The values in the table are emission control coefficients. Only the power industry uses the benchmark method to allocate carbon quotas and we calculate the emission control coefficient based on the benchmark. The benchmark value of the power industry is shown in brackets below the emission control coefficients. All data comes from the carbon emission quota allocation plan announced by the provincial Ecology and Environment Departments/Bureaus.

E Comparison of penalties imposed on the five and non-five major groups in the carbon market

Table A4: Number of penalized units (Provincial level)

Provinces		2021	2022	2023	2024
Anhui	Five groups	0 (0%)	0 (0%)	0 (0%)	0 (0%)
	Non-five groups	4 (8%)	4 (8%)	4 (8%)	4 (8%)
Beijing	Five groups	0 (0%)	0 (0%)	0 (0%)	1 (7%)
	Non-five groups	2 (13%)	2 (13%)	4 (27%)	6 (40%)
Chongqing	Five groups	0 (0%)	0 (0%)	0 (0%)	1 (5%)
	Non-five groups	3 (14%)	3 (14%)	4 (19%)	4 (19%)
Fujian	Five groups	0 (0%)	0 (0%)	0 (0%)	0 (0%)
	Non-five groups	2 (8%)	2 (8%)	5 (20%)	5 (20%)
Gansu	Five groups	0 (0%)	0 (0%)	0 (0%)	0 (0%)
	Non-five groups	6 (21%)	6 (21%)	7 (24%)	7 (24%)
Guangdong	Five groups	0 (0%)	0 (0%)	0 (0%)	0 (0%)
	Non-five groups	4 (4%)	6 (6%)	6 (6%)	6 (6%)
Guangxi	Five groups	0 (0%)	0 (0%)	1 (6%)	2 (12%)
	Non-five groups	0 (0%)	0 (0%)	0 (0%)	0 (0%)
Guizhou	Five groups	4 (13%)	4 (13%)	4 (13%)	4 (13%)
	Non-five groups	2 (7%)	4 (13%)	5 (17%)	5 (17%)
Hainan	Five groups	1 (14%)	1 (14%)	1 (14%)	1 (14%)
	Non-five groups	0 (0%)	0 (0%)	0 (0%)	0 (0%)
Hebei	Five groups	0 (0%)	1 (1%)	1 (1%)	2 (3%)
	Non-five groups	10 (13%)	10 (13%)	10 (13%)	10 (13%)
Heilongjiang	Five groups	4 (4%)	5 (5%)	5 (5%)	5 (5%)
	Non-five groups	30 (29%)	30 (29%)	31 (30%)	31 (30%)
Henan	Five groups	1 (1%)	1 (1%)	4 (5%)	4 (5%)
	Non-five groups	3 (4%)	3 (4%)	3 (4%)	3 (4%)
Hubei	Five groups	2 (6%)	2 (6%)	2 (6%)	2 (6%)
	Non-five groups	2 (6%)	2 (6%)	2 (6%)	2 (6%)
Hunan	Five groups	0 (0%)	0 (0%)	0 (0%)	0 (0%)
	Non-five groups	12 (31%)	12 (31%)	12 (31%)	13 (33%)
Jiangsu	Five groups	0 (0%)	0 (0%)	7 (3%)	11 (5%)
	Non-five groups	51 (21%)	51 (21%)	56 (23%)	63 (26%)
Jiangxi	Five groups	1 (5%)	1 (5%)	2 (10%)	3 (14%)
	Non-five groups	6 (29%)	6 (29%)	6 (29%)	6 (29%)
Jilin	Five groups	0 (0%)	0 (0%)	0 (0%)	0 (0%)
	Non-five groups	11 (24%)	12 (27%)	12 (27%)	13 (29%)
Liaoning	Five groups	0 (0%)	0 (0%)	1 (1%)	1 (1%)
	Non-five groups	14 (18%)	15 (19%)	15 (19%)	16 (20%)
Neimeng	Five groups	6 (4%)	6 (4%)	6 (4%)	6 (4%)
	Non-five groups	26 (18%)	26 (18%)	30 (21%)	30 (21%)
Ningxia	Five groups	4 (15%)	5 (19%)	5 (19%)	5 (19%)
	Non-five groups	1 (4%)	1 (4%)	1 (4%)	1 (4%)
Qinghai	Five groups	0 (0%)	0 (0%)	0 (0%)	0 (0%)

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Table A4 – *Continued from previous page*

Provinces		**2021**	**2022**	**2023**	**2024**
	Non-five groups	4 (50%)	4 (50%)	4 (50%)	4 (50%)
Shaanxi	Five groups	5 (8%)	5 (8%)	6 (10%)	7 (11%)
	Non-five groups	23 (37%)	23 (37%)	24 (38%)	24 (38%)
Shandong	Five groups	0 (0%)	0 (0%)	0 (0%)	0 (0%)
	Non-five groups	15 (10%)	15 (10%)	15 (10%)	15 (10%)
Shanghai	Five groups	1 (4%)	1 (4%)	3 (11%)	4 (15%)
	Non-five groups	10 (37%)	10 (37%)	11 (41%)	13 (48%)
Shanxi	Five groups	8 (13%)	8 (13%)	10 (16%)	10 (16%)
	Non-five groups	26 (25%)	29 (27%)	29 (27%)	29 (27%)
Sichuan	Five groups	1 (6%)	1 (6%)	1 (6%)	1 (6%)
	Non-five groups	1 (6%)	1 (6%)	1 (6%)	2 (12%)
Tianjin	Five groups	1 (4%)	1 (4%)	1 (4%)	2 (7%)
	Non-five groups	4 (15%)	4 (15%)	4 (15%)	5 (19%)
Xinjiang	Five groups	1 (2%)	1 (2%)	1 (2%)	1 (2%)
	Non-five groups	6 (14%)	6 (14%)	6 (14%)	7 (16%)
Yunnan	Five groups	2 (15%)	2 (15%)	2 (15%)	2 (15%)
	Non-five groups	4 (31%)	4 (31%)	4 (31%)	4 (31%)
Zhejiang	Five groups	1 (1%)	1 (1%)	6 (4%)	9 (6%)
	Non-five groups	17 (12%)	17 (12%)	22 (16%)	22 (16%)

Table A5: The installed capacity of penalized units (Provincial level, MW)

Provinces		2021	2022	2023	2024
Anhui	Five groups	0.0 (0%)	0.0 (0%)	0.0 (0%)	0.0 (0%)
	Non-five groups	880.0 (2%)	880.0 (2%)	880.0 (2%)	880.0 (2%)
Beijing	Five groups	0.0 (0%)	0.0 (0%)	0.0 (0%)	508.0 (5%)
	Non-five groups	280.58 (3%)	280.58 (3%)	696.58 (7%)	1361.58 (13%)
Chongqing	Five groups	0.0 (0%)	0.0 (0%)	0.0 (0%)	934.0 (7%)
	Non-five groups	80.0 (1%)	80.0 (1%)	740.0 (5%)	740.0 (5%)
Fujian	Five groups	0.0 (0%)	0.0 (0%)	0.0 (0%)	0.0 (0%)
	Non-five groups	550.0 (2%)	550.0 (2%)	4408.0 (14%)	4408.0 (14%)
Gansu	Five groups	0.0 (0%)	0.0 (0%)	0.0 (0%)	0.0 (0%)
	Non-five groups	1664.0 (8%)	1664.0 (8%)	1914.0 (9%)	1914.0 (9%)
Guangdong	Five groups	0 (0%)	0 (0%)	0 (0%)	0 (0%)
	Non-five groups	2580 (5%)	3780 (8%)	3780 (8%)	3780 (8%)
Guangxi	Five groups	0.0 (0%)	0.0 (0%)	120.0 (1%)	330.0 (2%)
	Non-five groups	0.0 (0%)	0.0 (0%)	0.0 (0%)	0.0 (0%)
Guizhou	Five groups	4200.0 (13%)	4200.0 (13%)	4200.0 (13%)	4200.0 (13%)
	Non-five groups	1740.0 (5%)	4140.0 (13%)	5340.0 (16%)	5340.0 (16%)
Hainan	Five groups	132.0 (3%)	132.0 (3%)	132.0 (3%)	132.0 (3%)
	Non-five groups	0.0 (0%)	0.0 (0%)	0.0 (0%)	0.0 (0%)
Hebei	Five groups	0.0 (0%)	1200.0 (2%)	1200.0 (2%)	1800.0 (4%)
	Non-five groups	2085.0 (4%)	2085.0 (4%)	2085.0 (4%)	2085.0 (4%)
Heilongjiang	Five groups	2955.0 (14%)	4155.0 (20%)	4155.0 (20%)	4155.0 (20%)
	Non-five groups	1185.8 (6%)	1185.8 (6%)	1285.8 (6%)	1285.8 (6%)
Henan	Five groups	780.0 (1%)	780.0 (1%)	3080.0 (5%)	3080.0 (5%)
	Non-five groups	1270.0 (2%)	1270.0 (2%)	1270.0 (2%)	1270.0 (2%)
Hubei	Five groups	615.6 (2%)	615.6 (2%)	615.6 (2%)	615.6 (2%)
	Non-five groups	526.5 (2%)	526.5 (2%)	526.5 (2%)	526.5 (2%)
Hunan	Five groups	0.0 (0%)	0.0 (0%)	0.0 (0%)	0.0 (0%)
	Non-five groups	762.5 (3%)	762.5 (3%)	762.5 (3%)	967.0 (4%)
Jiangsu	Five groups	0.0 (0%)	0.0 (0%)	5172.0 (5%)	7000.6 (7%)
	Non-five groups	3722.4 (4%)	3722.4 (4%)	6908.88 (7%)	9277.88 (9%)
Jiangxi	Five groups	440.0 (2%)	440.0 (2%)	3140.0 (14%)	3227.0 (14%)
	Non-five groups	245.5 (1%)	245.5 (1%)	245.5 (1%)	245.5 (1%)
Jilin	Five groups	0.0 (0%)	0.0 (0%)	0.0 (0%)	0.0 (0%)
	Non-five groups	519.0 (3%)	611.0 (4%)	611.0 (4%)	772.0 (5%)
Liaoning	Five groups	0.0 (0%)	0.0 (0%)	2400.0 (7%)	2400.0 (7%)
	Non-five groups	1720.6 (5%)	1744.6 (5%)	1744.6 (5%)	1768.6 (5%)
Neimeng	Five groups	4302.0 (5%)	4302.0 (5%)	4302.0 (5%)	4302.0 (5%)
	Non-five groups	13990.0 (15%)	13990.0 (15%)	17740.0 (19%)	17740.0 (19%)
Ningxia	Five groups	4140.0 (14%)	4800.0 (16%)	4800.0 (16%)	4800.0 (16%)
	Non-five groups	1320.0 (5%)	1320.0 (5%)	1320.0 (5%)	1320.0 (5%)
Qinghai	Five groups	0.0 (0%)	0.0 (0%)	0.0 (0%)	0.0 (0%)
	Non-five groups	775.0 (21%)	775.0 (21%)	775.0 (21%)	775.0 (21%)
Shaanxi	Five groups	5620.0 (13%)	5620.0 (13%)	5870.0 (14%)	7190.0 (17%)
	Non-five groups	2282.0 (5%)	2282.0 (5%)	3602.0 (9%)	3602.0 (9%)
Shandong	Five groups	0 (0%)	0 (0%)	0 (0%)	0 (0%)

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Table A5 – *Continued from previous page*

Provinces		**2021**	**2022**	**2023**	**2024**
	Non-five groups	3518 (7%)	3518 (7%)	3518 (7%)	3518 (7%)
Shanghai	Five groups	1300.0 (6%)	1300.0 (6%)	2687.4 (11%)	3547.4 (15%)
	Non-five groups	6589.44 (28%)	6589.44 (28%)	7514.64 (32%)	10009.04 (42%)
Shanxi	Five groups	8 (13%)	8 (13%)	10 (16%)	10 (16%)
	Non-five groups	7845 (20%)	9345 (24%)	9345 (24%)	9345 (24%)
Sichuan	Five groups	100.0 (1%)	100.0 (1%)	100.0 (1%)	100.0 (1%)
	Non-five groups	600.0 (6%)	600.0 (6%)	600.0 (6%)	1800.0 (17%)
Tianjin	Five groups	265.0 (2%)	265.0 (2%)	265.0 (2%)	1195.0 (7%)
	Non-five groups	526.0 (3%)	526.0 (3%)	526.0 (3%)	1187.0 (7%)
Xinjiang	Five groups	12.0 (0%)	12.0 (0%)	12.0 (0%)	12.0 (0%)
	Non-five groups	5420.0 (16%)	5420.0 (16%)	5420.0 (16%)	7520.0 (22%)
Yunnan	Five groups	2200.0 (18%)	2200.0 (18%)	2200.0 (18%)	2200.0 (18%)
	Non-five groups	4850.0 (39%)	4850.0 (39%)	4850.0 (39%)	4850.0 (39%)
Zhejiang	Five groups	405.0 (1%)	405.0 (1%)	4325.6 (7%)	6648.5 (11%)
	Non-five groups	2214.94 (4%)	2214.94 (4%)	6239.07 (10%)	6239.07 (10%)

F Proportion of Units Receiving Subsidies

As shown in Table A6, 85%, 78%, and 87% of Shandong, Shanxi, and Guangdong units received subsidies in 2021. This indicates that the current carbon intensity benchmark is too loose and has not solved the problem of reducing thermal power generation essentially. As the benchmark gradually tightens, the proportion of units receiving subsidies in the three provinces also dropped to 80%, 68%, and 53%, respectively.

Table A6: The Proportion of Units Receiving Subsidies to the Total Units

Province	**2021**	**2022**	**2023**
Shandong	85%	85%	80%
Shanxi	78%	76%	68%
Guangdong	87%	86%	53%

G Carbon Price under Different Benchmark Level

To calculate the carbon price under different benchmark levels, we first collected the expected carbon price under different benchmarks based on the simulation results of Yu et al. (2022). Then, the actual carbon price under the current benchmark was used to calibrate with the simulated carbon price results and obtain the adjustment coefficient. Based on the adjustment coefficient, we adjusted the simulated carbon prices under the corresponding benchmark levels, as shown in Table A7. Taking the carbon price results as anchors, we simulated the carbon price series under the benchmark that can lead to effective carbon pass-through through the proportional amplification of the existing carbon price level and the addition of certain random disturbances.

Table A7: Emissions Intensity Benchmark and Expected Carbon Price

Coal-fired units ($> 300MW$)	**Coal-fired units** ($\leq 300MW$)	**Gas-fired units**	**Carbon price (CNY/ton CO_2)**
0.753	0.841	0.347	109.76
0.731	0.815	0.337	137.14
0.709	0.791	0.327	174.56
0.687	0.767	0.317	239.36
0.667	0.744	0.307	346.44
0.647	0.721	0.298	498.56
0.608	0.679	0.280	714.97