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Preprint

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Suggested Citation: Bento, Antonio M.; Koch, Nicolas; Marmarelis, Zissis E. (2026) : Emergency Response Mechanisms for addressing challenges with high gas prices in international energy markets, ZBW - Leibniz Information Centre for Economics, Kiel, Hamburg

This Version is available at:

<https://hdl.handle.net/10419/337665>

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Emergency Response Mechanisms for addressing challenges with high gas prices in international energy markets

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Abstract

Recent natural gas price surges prompted the adoption of various policies, such as a natural gas price cap, aimed at preserving climate goals and preventing increases in wholesale electricity prices. However, it is unclear whether such policies are effective. Here, we take advantage of the unexpected spike in natural gas prices around the time of the Russian invasion into Ukraine to estimate the effects of such a spike on coal generation, carbon emissions, and wholesale electricity prices, highlighting its heterogeneous impacts in 13 EU countries that still rely on both coal and gas for electricity production. We use these estimates to show that the effectiveness of the gas price cap is limited, and instead propose an emergency response mechanism that would *simultaneously* safeguard the EU's climate policy and protect households from excessive fluctuation in natural gas prices. The proposed mechanism introduces an emergency auction reserve price within the existing EU Emissions Trading System, triggered automatically under predefined rules whenever gas prices reach unusually high levels. Revenues generated by the reserve price would be used to provide relief to consumers. Our results demonstrate that a modest emergency reserve price could serve as an effective response mechanism and that this approach overcomes key shortcomings of the widely used natural gas price cap.

Keywords: European energy crisis, excessive natural gas prices, decarbonization, wholesale electricity prices, emergency response mechanisms, emission trading

Episodes of extraordinarily high natural gas prices in international energy markets can compromise the effectiveness of climate policy and the pace of decarbonization, prompting the switch from gas to coal in the generation of electricity [1]. Higher natural gas prices can also lead to increases in wholesale electricity prices, impacting consumers and the rest of the economy [2]. Due to its dependence on Russian gas, the European energy system faces unique challenges [3]. The unexpected spike in natural gas prices following the Russian invasion of Ukraine in February 2022 underscores such challenges. In a year, gas prices increased by nearly 600 percent - from 18 euros per megawatt-hour (EUR/MWh) in March 2021 to 124 EUR/MWh in March 2022, achieving record high levels of about 300 EUR/MWh by September 2022 (Figure 1 Panel A). In this period, coal prices also surged by nearly 500 percent, reflecting gas-to-coal substitution (Figure 1 panel C). Despite an almost doubling of carbon price levels under the EU Emissions Trading System (EU ETS) from 45 EUR/tonne to 75 EUR/tonne (Figure 1 Panel D), coal power generation raised by 42 percent EU-wide (Figure 1, Panel B). Wholesale electricity prices also increased steadily from about 82 EUR / MWh to more than 200 EUR / MWh (Figure 1, panel E). While since September 2022 natural gas prices have declined (Figure 1, Panel A), over the course of 2025, prices for gas futures contracts with delivery in the year 2026 are still almost 100 percent higher than pre-crisis level, suggesting a new normal of higher gas prices. At the same time, future increases in the global demand for natural gas, as well as geopolitical challenges, could well revive price volatility and trigger renewed price spikes, as seen in early March 2026 when gas prices roughly doubled within a week to about 66 EUR/MWh following the escalation of the Iran conflict.

In response to the challenges that higher natural gas prices pose in relation to electricity prices and carbon emissions, some European nations have called for a faster transition away from fossil fuels through aggressive investments in carbon-free technologies to reduce Europe’s exposure to natural gas markets [4]. Others, like Poland, have urged a delay in stricter climate action amid the crisis. The EU has implemented a uniform cap on natural gas prices at 180 EUR/MWh in late 2022, and considered various electricity price controls starting in October 2023 ([5],[6],[7]). These interventions have come under scrutiny as critics are unsure if they provide a clear solution to the soaring prices of natural gas and its impacts on consumers ([8, 9]). In principle, countries that have implemented an ETS to regulate greenhouse gas emissions have the potential to effectively address the challenges that high gas prices pose within the design of the ETS. However, in practice, no existing ETS has a direct response mechanism that could alleviate the effects of international energy price crises by automatically triggering an emergency mechanism in the auctions of carbon permits. Such a rule-based mechanism could apply an emergency auction reserve price that would set to contain the gas-to-coal switch. In addition, the revenues generated through this auction reserve price could be used to provide relief to consumers.

Three largely disconnected strands of literature are relevant for designing policies that mitigate the effects of unexpected natural gas price spikes on decarbonization and electricity prices. First, a substantial body of work examines the importance of fuel switching, particularly gas-to-coal switching, in energy transitions [10–15], highlighting that high natural gas prices induce coal use and associated CO₂ emissions. Second, another literature analyzes the pass-through of fuel costs to wholesale electricity prices [16], typically in country-specific contexts, including the United States [17], Spain [16], Germany [18] and Nordic countries [19], showing that high natural gas price translate to electricity price increases that can burden consumers. Third, a separate line of research studies long-term stabilization mechanisms in emissions trading systems—such as price floors, ceilings, and collars—that aim to reduce intertemporal volatility in abatement costs [20]. Despite their relevance to a common policy challenge, these three strands have not been systematically integrated. As a result, we lack a unified framework for assessing how an emissions trading system can be made resilient to short-lived but extreme episodes of natural gas price spikes. Our contribution is such a unified framework that lies at the intersection of these literatures. It allow us to conceptualize and compare alternative policy options that aim to simultaneously protect consumers against high energy prices and not compromise decarbonization goals. Identifying robust emergency response mechanisms is important because political economy pressures, stemming from commitment challenges and distributional concerns, intensify during periods of energy price crisis. Absent evidence-based guidance for predictable, rule-based response mechanisms, policymakers revert to ad hoc interventions that risk distorting incentives and weakening long-term climate policy commitments.

In this paper, we propose an emergency response mechanism within the existing emissions trading architecture that would enhance the resilience of the climate policy against the energy crisis, and compare its effects against gas price caps, which to date are the most widely used policy to tackle the impacts of unexpected high energy prices. We propose an empirical framework that provides the analytical toolkit to quantify how excessive natural gas price spikes compromise climate policy and to conceptualize and assess different policy responses based on their environmental effectiveness and capacity to address wholesale

electricity prices. The 2022 energy crisis following the Russian invasion of Ukraine provides the empirical context upon which we bring this framework to bear on the data. We first take advantage of the unexpected, plausibly exogenous spike in natural gas prices around the time of the Russian invasion to Ukraine of February 2022 to estimate the causal effects of such a spike on coal generation and resulting carbon emissions, highlighting its heterogeneous impacts across 13 EU countries that still rely on both coal and gas for electricity production. Specifically, we employ regression techniques using rich hourly electricity market data. Second, by combining our empirical estimates with estimates of the impacts of natural gas prices on wholesale electricity prices, we examine the emissions and wholesale price effects of the 180 EUR/MWh natural gas price cap already implemented by the EU. Third, we propose an alternative emergency response mechanism within the EU ETS and contrast its performance against the EU gas price cap. This emergency response mechanism would build on the existing framework of the Market Stability Reserve, which already provide the institutions for rule-based interventions in the auctioning of emission permits in the EU ETS. It would be triggered automatically according to a predefined rule whenever gas prices reach levels substantially above their historical trends. Upon activation of the emergency mechanism, emission permits would be auctioned temporarily only if bids exceed a prespecified minimum price—what we refer to as the emergency reserve price. This reserve price would be set to keep the relative price of gas to coal constant at a defined historical reference level. The proposed emergency mechanism is designed as a “second-best” policy that preserves the political and dynamic integrity of the ETS under conditions of market stress, and that constrain policymakers from resorting to ad hoc interventions.

Compared to the existing gas price cap, the proposed mechanism offers some advantages. First, a small increase in the price of carbon is relatively more effective in reducing carbon emissions than a cap on the price of gas. Two underlying channels of adjustment drive this difference. Both instruments explore what we term the *substitution effect* by limiting substitution away from gas toward coal. However, a gas price cap effectively subsidizes the price of wholesale electricity, leading to an increase in demand and resulting emissions. We term this effect the *output effect*. In contrast, a higher carbon price induced by the proposed emergency reserve price contracts the electricity demand and reduces carbon emissions by raising the price of electricity. In other words, only with the emergency mechanism proposed here will the substitution and output effects reinforce each other, maximizing the potential of emissions reductions. Second, the emergency response mechanism has the advantage of generating revenues, which can be used to alleviate the consequences of higher electricity prices. Taken together, we show that a modest emergency levy of 12.18 EUR/tonne on top of the regular carbon price in the EU ETS could serve as an effective response mechanism to reduce excess emission from the gas price spikes. Such a mechanism would generate greater relief to consumers than a natural gas price cap.

Results

In Figure 2, we show how the episode of extraordinarily high natural gas prices during the 2021/2022 crisis has affected CO₂ emissions from coal and therefore the pace of decarbonization in the electricity sector (panels A-D), and wholesale electricity prices (panels E-G), which affect consumers and the rest of the economy. Our focus is on the 13 EU countries that still rely on coal and gas for electricity production. In addition, our analysis focuses on the period between April 2021 and May 30 2022 to isolate the effect of natural gas price spikes triggered by plausibly exogenous geopolitical events (see Figure 1). The restriction to this time period also minimizes any empirical challenge arising due to other observed or unobserved time-varying factors, such as potential confounding policy responses to the crisis or (longer-term) changes in generation capacity in different countries (see Supplementary Discussions 1.1 and 1.2).

CO₂ emission increase from natural gas price surge

Figure 2 panels A and B quantify the excess coal generation and the excess CO₂ emissions from natural gas to coal switching in the generation of electricity induced by the unexpected, plausibly exogenous surge in the price of natural gas around the time of the Russian invasion of Ukraine in the period between April 2021 and May 2022. Excess coal generation and excess CO₂ emissions are presented relative to a counterfactual scenario, in which the relative price of natural gas to coal – subsequently referred to as relative gas price – remains at the low pre-crisis price level (34% lower than in the crisis period). For instance, for Germany we calculate that annual CO₂ emission are about 43,572 kt or 27% above this counterfactual scenario. The overall increase in emissions of 19% or 73,587 kt in all our sample countries provides clear evidence that the episode of extraordinarily high relative gas prices in the aftermath of the Russian invasion of Ukraine compromised the pace of decarbonization of the electricity sector in the EU.

Quantified excess coal generation and excess CO₂ emissions are determined by the product of the responsiveness of coal-fired power generation to the relative gas prices shown in Figure 2D and the quantity of coal-fired electricity generated shown in Figure 2F (see Methods). Our estimates of the price responsiveness of coal generation (see Methods for the underlying regression techniques) suggest a large heterogeneity across the 13 EU countries in the magnitude of the gas-to-coal switching occurring in response to high relative gas prices. We find the greatest effects for Italy (0.75) and Spain (0.71). The estimate of 0.75 for Italy suggests that the generation of coal increases by 75% if the relative price of gas increases by one unit. The effects are more moderate in Finland, Germany, and Denmark, while they are much less pronounced in Eastern and Southeastern EU countries. A high relative price responsiveness of coal generation translates into a high *relative* increase in coal generation and CO₂ emissions. This is why we observe in Figure 2B the largest relative emission increase induced by the rise in the price of natural gas in Italy and Spain (50% and 48%). However, the *absolute* emission increase in these two countries is limited. This is because the total amount of coal-fired power generation drives the absolute emission effect and the dependence on coal is relatively low in Italy and Spain (Figure 2F). In contrast, more coal dependent countries such as Germany, Poland, Czechia, and Bulgaria show high absolute emission increases - despite their medium to small responsiveness to relative gas prices.

Electricity price increase from natural gas price surge

In addition to the increasing emissions resulting from the substitution from natural gas to coal power generation, high natural gas prices also pass through to higher wholesale electricity prices. Figure 2E quantifies the excess wholesale electricity price increase induced by the 2021/2022 natural gas price surge relative to the counterfactual scenario, in which the relative gas price remains at the low precrisis price level. We find the greatest effects for the southern EU countries, where Greece stands out with an increase in electricity price of 131 € / MWh (245%). The price increase is lowest in Northern Europe, such as 59 €/MWh (120%) in Finland.

The quantified excess electricity prices are determined by the pass-through rate of natural gas prices to wholesale electricity prices (Figure 2F) and the level of wholesale electricity price (Figure 2G). Our estimates of the pass-through rates (see Methods for discussion of underlying regression techniques) again suggest important heterogeneity in the extent to which high natural gas prices trigger higher electricity prices across the 13 EU countries. We find the greatest effects for Italy (1.96) and the Netherlands (1.9) and the least effects for Poland (0.79) and Bulgaria (0.54). The estimate of 1.96 for Italy suggests that an increase of 1 EUR / MWh in the natural gas price results in an increase of 1.96 EUR / MWh in the wholesale electricity price. Because the heterogeneity in the electricity price levels is limited (Figure 2G), it is mainly the pass-through rate that drives the relative and absolute increase in wholesale electricity prices observed in Figure 2E.

Heterogeneity in the adjustment

In Figure 3, we decompose the channels of adjustment behind the *average* effects for the gas-to-coal substitution and the electricity price in response to the higher relative natural gas price by showing hourly estimates for the responsiveness of coal generation (left panel) and the responsiveness of electricity price measured by pass-through rates (middle panel) for six selected countries with different combinations of electricity (right panel). It shows clear hourly patterns in the two responsiveness estimates. The electricity load is one driver of these temporal patterns. In times of high load during the morning and evening peaks, we generally observe a higher responsiveness of either coal generation (i.e. more gas-to-coal switching) or electricity prices (i.e. a higher pass-through of natural gas prices). The mix of electricity generation technologies is a second driver of temporal heterogeneity. For example, in times with abundant intermittent renewables (IRE), we generally observe a lower response of coal generation to the relative price of gas. Taken together, three different cases of adjustment can be identified from the temporal response patterns.

First, for coal-dependent countries, such as Poland and Czechia, we show a negative correlation between coal generation responsiveness and electricity price responsiveness. In particular, during hours of high electricity load (shown as dashed line in the right panel), we observe a high coal generation responsiveness but a lower electricity price responsiveness. This suggests that these two Eastern European countries use their coal capacity to balance out fluctuations in gas prices, and the available coal capacity keeps electricity prices from rising. A similar adjustment mechanism can be observed in Greece, where, however, coal capacity is not sufficient to prevent electricity price increases in the evening peak.

Second, for countries with a high share of IRE but also nuclear energy, namely Finland and Spain, we instead find a positive correlation between the coal generation responsiveness and the electricity price

responsiveness. During periods of high electricity load, these two countries do not have sufficient coal capacity that could be used to replace more expansive gas generation, and thus the higher generation costs must be passed through higher electricity prices.

Finally, Germany is an example of a country with a relatively high share of IRE but still a high share of coal. With a correlation between the coal generation responsiveness and the electricity price responsiveness close to zero, the country falls between the two cases with a clear positive and negative correlation, suggesting that in times of high relative gas prices, it can use gas-to-coal switching to prevent some of the electricity price increase but not to a larger extent as Poland and Czechia. It is worth noting that coal-fired plants generally lack the fast-ramping capabilities of gas-fired units that make the latter particularly well suited to balancing intermittent renewable generation, which can constrain the extent of fuel switching.

Trade-off between gas-to-coal switch and higher electricity price

The pattern with trade-offs between switching to more coal generation or paying higher electricity prices discussed for the six selected countries generalizes across all our sample countries (see Supplementary Figures 20 to 26). To show this, Figure 4A presents a relative responsiveness score that is based on the negated correlation coefficient between the hourly estimates for the coal responsiveness and for the price pass-through (see Methods). The higher the score, the more negatively correlated the response of the coal and the pass through of the price. In addition to Czechia, Poland and Greece, all other Eastern European countries but also Italy and the Netherlands are among the group of countries with a high relative responsiveness score. In most cases, these countries rely on coal to balance out high natural gas prices and keep electricity prices from rising. However, in some countries such as Italy (Supplementary Figure 24) and the Netherlands (Supplementary Figure 25) and in some periods of the day (such as late afternoon in Greece, but also Czechia and Poland), the high responsiveness score reflects cases with rising electricity prices because coal generation does not respond.

In contrast, a second group of countries is characterized by a negative score (i.e. a positive correlation between the coal responsiveness and the price pass-through), which suggests that the switch from gas to coal generation in these countries is insufficient to stop electricity prices from increasing or that the country uses some alternative generation technology that prevents gas-to-coal switching. This group includes Finland and Spain, but also Croatia and Denmark, i.e., those countries that have a high share of decarbonized electricity and a relatively low coal capacity.

Figure 4B and 4C suggest that the electricity mix is the determinant of the trade-off countries face when dealing with higher relative natural gas prices. A higher reliance on coal generation is correlated with a higher responsiveness score and a higher share of decarbonized energy is correlated with a lower score (specifically, high shares of wind and hydro energy are correlated with a lower score; Extended Data Fig. 4).

Effectiveness of EU gas price cap is limited

In response to the 2021/2022 natural gas price surge, the EU implemented a price cap, aiming to "limit episodes of excessive gas prices".¹ The so-called "Market Correction Mechanism" is automatically activated if the month-ahead price for natural gas on the Title Transfer Facility (TTF) trading platform exceeds 180 EUR/MWh for three working days.² Even though the EU-wide mechanism was only applied from February 2023 when the crisis was already subsiding, it remains relevant to understand how it would have worked if it had already been active in 2022 when natural gas prices still soared. Figure 5A shows results for this policy counterfactual. It indicates that the emissions savings from a natural gas price cap in 2022 would have been low in most countries except Germany. For the EU in total, we estimate minor CO₂ emission savings of 7,717 Kt CO₂. The environmental effectiveness is low despite the fact that the 180 EUR/MWh threshold would have been triggered 115 times in the year, as 2022 stands out as the period with record natural gas prices hitting an all-time high of more than 300 EUR/MWh (see Figure 1 & Supp. Fig. 14).

Figure 5B highlights the channels exploited by the natural gas price cap and underscores why its effectiveness is limited. It shows two opposing effects of the cap. First, there is an emission-reducing

¹ Council Regulation (EU) 2022/2578 of 22 December 2022 establishing a market correction mechanism to protect Union citizens and the economy against excessively high prices. <https://eur-lex.europa.eu/eli/reg/2022/2578/oj>

² The second market event triggering the mechanism is when the month-ahead TTF price is 35 EUR/MWh higher than a global reference price for LNG for the same three working day. Once activated, the cap is valid for at least 20 working days. It will be automatically deactivated if gas prices are below 180€/MWh for the last three consecutive working days.

substitution effect. By capping natural gas prices, less gas-fired power generation is substituted by coal-fired generation, and this results in lower CO₂ emissions. However, there is a second, emissions-increasing output effect. The lower gas prices imposed by the cap are passed through to lower wholesale electricity prices, which increases electricity demand and, thus, increases CO₂ emissions. Figure 5C shows the induced electricity price decrease that causes this output effect.

Small carbon price increase can effectively reduce excess emissions

Strengthening the carbon price in the existing EU Emissions Trading System (EU ETS) is an alternative policy option that could more effectively address excess CO₂ emissions. A higher price on carbon makes coal effectively more expensive than natural gas, and thus works in the same direction as a price cap on natural gas which makes natural gas cheaper. We calculate that the additional price of carbon that would generate the same substitution effect that the cap on the price of natural gas yields amount to 12.18 EUR/tonne (see Methods). In comparison, the average carbon price in the EU ETS in 2022 was 80 EUR/tonne.

Figure 5A shows that the cap-equivalent carbon price would deliver more significant CO₂ emission reductions because, in sharp contrast to the natural gas price cap, there is a negative output effect (Figure 5B). This is because electricity prices would increase to some extent (Figure 5C), which reduces electricity demand. For the EU in total, we estimate that the 12.18 EUR/tonne carbon price would reduce CO₂ emission by 14,048 kt of CO₂, which is a reduction nearly twice that of the gas price cap.

Consumer relief from gas price cap vs. carbon price with revenue recycling

Finally, Figure 5D compares the financial burden and relief from the gas price cap and the equivalent carbon price. The addition of a carbon price of 12.18 EUR/tonne imposes higher electricity costs on consumers (blue bar), and the increase in the electricity price is more pronounced in countries with a high relative responsiveness score (see Extended Data Figure 1). However, the 12.18 EUR/tonne carbon price also raises additional revenues (pink bar) that can be used for consumer compensation. These revenues are significantly larger than the aggregate burden (pink bar > blue bar), with the break-even value of revenue to burden being 8 percent on average. Thus, a recycling of revenues could fully offset the carbon cost burden and provide an additional consumer relief of considerable magnitude (equal to the difference between the blue and pink bars, as seen in Figure S6). The natural gas price cap also provides consumer relief through lower electricity prices (green bar). However, the financial compensation from a full revenue recycling of the additional carbon price of 12.18 EUR/tonne would far exceed that from the gas price cap. For example, in Spain only 32% of the revenues would be required to deliver the same level of consumer relief as the gas price cap (as indicated by the percentage values under each country's bars). Even under a pessimistic scenario in which administrative and transaction costs associated with such recycling reduce the available revenues for compensation by half, revenue recycling would still provide greater relief than the gas price cap in almost all countries.

In sum, our analysis suggests that a moderate strengthening of the EU ETS combined with a financial compensation of consumers equal to all additional carbon revenues outperforms a gas price cap both in terms of environmental effectiveness but also providing a consumer relief during the crisis.

Discussion

Our study reveals the critical importance of understanding the relationship between natural gas price spikes, coal-fired generation, and resulting excess CO₂ emissions. The results confirm that the use of natural gas as a transition fuel has potential shortcomings ([22], [23]). In particular, we provide convincing empirical evidence that episodes of extraordinary high gas prices compromise the pace of decarbonization by generating excess CO₂ emissions in electricity production. The response of coal-fired generation to spikes in gas prices is related to the share of coal in the electricity energy mix, the diversity of energy sources in electricity production, and how responsive a country is to natural gas prices. Countries with a mix of electricity generation that still rely relatively more on coal and are more sensitive to gas prices tend to experience the largest excess CO₂ emissions. Given the complementarities between natural gas and renewables, countries that invested in renewables as a decarbonization strategy are still at risk of increased CO₂ emissions due to their high responsiveness to natural gas prices, but the resulting increase in excess emissions is relatively smaller given their limited coal capacity. Taken together, these results point to the importance of accelerating coal phase out and diversifying energy sources, since coal can have a comeback during times with extraordinary high natural gas prices. In this sense, the analysis complements recent

literature that stresses the need of promoting a zero-carbon electricity sector to achieve climate goals [24],[25].

Because European electricity systems are physically constrained and highly interconnected, fuel-switching possibilities are shaped by transmission capacity, congestion, ramping constraints, and interconnector availability. Our empirical strategy relies on realized hourly generation and price data during the crisis period. These observed market outcomes already incorporate prevailing physical and institutional constraints within each national system. Accordingly, the estimated fuel-switching elasticities reflect substitution that was feasible under actual system conditions. Cross-country heterogeneity in estimated responses therefore captures differences in generation portfolios, grid structure, interconnection capacity, and operational flexibility. Our analysis is thus reduced-form and equilibrium-based, rather than a simulation of unconstrained engineering dispatch.

Several important policy insights can be drawn from our findings. First, the effectiveness of the existing EU gas price cap is limited. Our framework reveals the underlying mechanisms that lead to this result. By lowering the price of gas relative to coal, the gas price cap promotes a substitution effect that leads to a reduction of emissions. However, to the extent that gas price caps lower the overall wholesale electricity price, electricity demand and emissions increase. This output effect partly neutralizes the substitution effect, compromising the effectiveness of the gas cap. This insight suggests that the gas price cap suffers from some of the same limitations noted in studies that examined the effectiveness of low carbon fuel standards ([26]), and Clean Energy Standards ([27]).

Second, a small carbon price in the existing EU emission trading system can overcome the limitations of the gas price cap. In the 2022 crisis, a carbon price of 12.18 EUR/tonne would reduce CO₂ emissions more than twice as much as from a gas price cap. This carbon price can generate the same substitution effect as the gas price cap. But because wholesale electricity prices increase with a carbon price, the output effect will instead reinforce the substitution effect. This insight suggests potentially important reforms for the existing EU ETS. A fundamental implication of our study is that the EU ETS, as well as most existing emissions trading schemes, would benefit from an explicit emergency mechanism to address international energy price crises. Recent policy debates in Italy—including a reform proposals to decouple carbon costs from wholesale electricity prices in order to reduce consumer bills, and broader public calls to reconsider elements of the EU ETS to better balance decarbonization goals with energy costs—underscore the relevance of a predictable, rule-based mechanism that preserves the credibility and integrity of the ETS under conditions of market stress.

Political economy considerations are the "second-best" rationale for our proposal of a rule-based emergency mechanism. In a first-best setting, temporary surges in coal use and emissions would not pose a concern, as the emissions cap in the EU ETS fixes cumulative emissions. However, this perspective overlooks two important real-world dynamics. First, high energy prices trigger policy debates about the political commitments to the EU ETS cap. Because the cap is not static but subject to periodic updates and unexpected policy revisions, the literature has long recognized that policymakers governing an ETS face a classic time-inconsistency problem with ex-post incentives to renege on ex-ante commitments [28, 29]—with these pressures intensifying during periods of crisis [30, 31]. The proposal of Poland and other Eastern European countries to abandon the scheduled tightening of the EU ETS cap following the onset of the war in Ukraine [32] exemplifies the commitment problem that can arise during crisis. Although the proposal failed to gain majority support, the political debate surrounding the long-term cap's stringency induced uncertainty among market participants. Such uncertainty has been shown to deter investment in clean technologies, potentially undermining the dynamic efficiency of the ETS [33]. The proposed emergency mechanism for the EU ETS would act as a commitment device designed to preserve the political and dynamic integrity of the ETS under conditions of market stress. Second, the first-best perspective neglects policymakers' concerns about the political repercussion of distributional impacts associated with high energy prices during crisis. These concerns often trigger calls for relaxing climate policy or for alternative interventions that promise financial relief. Absent of a readily available mechanism to address them, policymakers tend to adopt ad hoc measures that distort incentives and are limited in their effectiveness. The EU's introduction of the gas price cap in 2022 is a salient example of such an ad hoc intervention. The emergency mechanism would act as rule-based device aimed at providing a predictable response to distributional concerns, which should constrain policymakers from resorting to ad hoc interventions.

Currently, the EU ETS lacks a dedicated emergency mechanism. However, the Market Stability Reserve (MSR) of the EU ETS already provides an institutional framework for rule-based interventions, and extending its mandate presents an administratively feasible way to integrate the proposed emergency levy into the existing governance architecture. The MSR automatically adjusts the supply of emission

allowances (EUAs) according to *quantity-based* rules: when the number of allowances in circulation falls below a specified threshold, allowances are released from the MSR for auctioning, and when it exceeds an upper threshold, a fraction of the surplus is withdrawn.³ The emergency mechanism could be incorporated into the MSR via an additional *price-based* rule: when natural gas prices exceed a prespecified threshold, allowances would be auctioned with a predetermined top-up. Price-based mechanisms of this type are well established in the literature [34–36] and already implemented in the UK, California, or in the U.S. Regional Greenhouse Gas Initiative—indicating that existing institutions have the administrative capacity to implement such schemes. Even within the EU ETS, Article 29a in principle already provides for a price-based emergency intervention linked to the carbon price: if EUA prices rise “more than twice” the two-year average and the increase is not “justified by fundamentals”, the European Commission may release additional allowances. However, this rule is discretionary and has never been used. By contrast, the emergency mechanism proposed here would be rule-based and linked to natural gas price levels.

The implementation of the emergency mechanism within an extended MSR framework requires defining three rules. The first defines the criterion for identifying excessive high natural gas prices that would trigger the mechanism. A simple option is to specify a fixed absolute price level, such as the 180 EUR/MWh threshold used for the EU gas price cap. An alternative option, following the logic of Article 29a, is to define the threshold based on a proportional increase in natural gas prices (or in the relative price of natural gas to coal) relative to a historical reference period—for instance, a rise exceeding twice the two-year average natural gas price. Once the average natural gas price over the preceding month exceeds the prespecified threshold, the emergency mechanism is activated automatically. Upon activation, a second rule determines a reserve price that applies temporarily to all EUA auctions. Under this rule, allowances in auctions are only released when the bid price exceeds the prespecified minimum—what we refer to as the emergency reserve price. A simple way to set this reserve price is to add a fixed top-up, such as 10 EUR per ton, to the average bid price in the previous auction round. A more flexible alternative, adopted in our policy counterfactual analysis above, is to define the top-up based on the actual carbon price increment required to keep the relative price of natural gas to coal (i.e., the gas-to-coal price ratio) constant at a specified historical reference level—for instance, again, the two-year average relative price of natural gas to coal. The calculation of this equivalent carbon price is straightforward for any combination of natural gas and coal prices (see Methods).⁴ A third rule determines the duration of the emergency activation. Following the design of Article 29a, we propose a fixed period of six consecutive months. After six months, the price situation would be reassessed.

From a political feasibility perspective, a challenge of the emergency mechanism is that it raises electricity prices precisely during periods of already high energy costs. However, our analysis has shown that the emergency reserve price generates revenues far exceeding the aggregate household costs from the resulting electricity price increase. In our counterfactual analysis for the 2022 energy crisis, only about 8 percent of the revenue would have been needed to fully offset the rise in consumer costs. This demonstrates that, even after accounting for administrative costs of the scheme, the emergency mechanism has substantial potential to provide meaningful relief to households. Recent literature on public support for carbon pricing ([37],[38],[39]) suggests that designing a revenue recycling scheme is a necessary condition for the political acceptability of such policies. While the EU lacks a legal framework for direct financial transfers to citizens, existing EU ETS compensation funds already provide an institutional foundation for a refund mechanism. Notably, the Social Climate Fund (SCF), established to offset costs from carbon pricing [40], could serve this purpose.⁵ It is financed through ETS auction revenue and it distributes these funds to EU Member States according to a formula designed to mitigate distributional tensions across the diverse EU economies. Member States then use the funds they receive *conditionally* on national Social Climate Plans approved by the EU, which determine how citizens are compensated. All revenues generated by the proposed emergency mechanism (net of administrative costs) could be channeled into the SCF. It would be in the self-interest of Member States to utilize the additional revenues from the emergency mechanism to provide financial support directly to households in times of crisis.

We acknowledge some limitations of the proposed emergency mechanism. First, while we focus on the potential of providing relief to consumers by recycling the revenues of the emergency mechanism, our study abstracts from consumers’ attitudes towards taxation and trust in the ability of the regulator to

³More specifically, the rule is based on the Total Number of Allowances in Circulation (TNAC). If the TNAC exceeds 833 million, 24% of the surplus is placed in the MSR. If the TNAC falls below 400 million, 100 million allowances are released.

⁴Specifically, this calculation is as follows:

$$\text{Mean}_{2022} \left[\frac{P_{\text{Gas}} + (P_{\text{ETS}} + \Delta C) \cdot EF_{\text{Gas}}}{P_{\text{Coal}} + (P_{\text{ETS}} + \Delta C) \cdot EF_{\text{Coal}}} \right] = \text{Mean}_{2022 \text{ GasCap}}(\text{Relative Price})$$

⁵The SCF was established in the context of extending the EU ETS to buildings and road transport.

actually deliver on the promise of recycling the revenues to provide consumer relief. In fact, studies highlight that public acceptability of carbon taxation depends, in part, on explicit ex ante clarity of its revenue use ([41],[42]). In the context of the COVID pandemic, state capacity to transfer funds directly to citizens has been identified as a key prerequisite for a credible compensation policy [43]. This raises broader questions about the long-term reliance on indirect redistribution mechanisms in the EU, such as the SCF or similar COVID-era assistance programs, particularly in the context of future crisis responses. Second, we also abstract from potential behavioral failures that may lead consumers to disproportionately pay attention to the increase in wholesale electricity prices that result from a higher carbon tax and potentially underestimate the true benefits that recycling revenues can provide ([44]. Third, we abstract from potential competitiveness effects from higher electricity prices for industry that may require additional compensation mechanisms. Forth, we acknowledge that the proposed emergency mechanism would add another layer to the already complex EU ETS architecture. However, it could build exclusively on existing MRS institutions, and unintended interaction with the current framework are unlikely. This is because the MSR's quantity-based rules are designed to address longer-term structural imbalances in the EU ETS. Activation is determined by the total number of allowances in circulation, but there is a two-year gap between the year it is measured and the year of the MSR intake or release. By contrast, the proposed, price-based emergency mechanism would respond immediately to excessive gas prices and operate only for a short, predefined period, such as six months. Given this limited and temporary nature, it is unlikely that the emergency intervention would materially influence the MSR activation two years later.

Finally, our analysis focuses on short-run operational responses during a crisis episode and does not explicitly model long-run capital adjustment. Nevertheless, the proposed emergency mechanism may have implications beyond the short run. By preserving a credible and undistorted carbon price signal during periods of extreme gas price volatility, the mechanism can help maintain stable investment incentives for renewables, storage technologies, demand response, and electrification. In contrast, recurrent interventions that suppress electricity prices through gas price caps risk weakening long-run investment signals and increasing policy uncertainty. At the same time, the relevance of the mechanism is likely to evolve as the electricity system decarbonizes. In the short run, when coal and gas plants remain central to marginal electricity supply, large gas price shocks can induce substantial fuel-switching toward more carbon-intensive generation. However, as investment in renewables, storage, and demand flexibility expands and the fossil share of marginal generation declines, extreme gas price movements should have a smaller impact on aggregate emissions and wholesale prices. In such a setting, the emergency mechanism would be activated less frequently. The instrument is therefore inherently transitional and state-dependent: its importance diminishes as reliance on fossil fuels declines.

Methods

Data and Sample

The majority of our data for the econometric analysis is obtained from the association of European Transmission System Operators (ENTSO-E) for each Transmission System Operator (TSO)—TSOs generally correspond to countries, with the exception of Germany and Denmark, which are split into four and two respectively. We obtain hourly data on wholesale electricity prices (EUR/MWh), electricity generation by technology (MWh), and Load (MWh). Hourly energy generation is obtained for each available source in each country and includes biomass, coal, lignite, natural gas, dispatchable hydro, nuclear, oil, solar, geothermal, wind, hydro-run-of-river, waste, and “other”. We focus on those 14 European Union countries that utilize hard coal or lignite, in addition to natural gas, in their electricity mix (Supp. Fig. 9 & Extended Data Fig. 3). This is a requirement for our empirical approach to work as we aim to quantify the substitutability between coal sources and natural gas. As such, we are left with Bulgaria, Croatia, Czechia, Denmark, Spain, Finland, Germany, Greece, Hungary, Ireland, Italy, the Netherlands, Poland, and Romania. The island states of Malta and Cyprus do not have available electricity generation data, while Ireland is left out of the policy analysis (Figures 4 & 5) due to missing electricity price data.

Price data of natural gas, coal and carbon prices are obtained from the Intercontinental Exchange (ICE). The natural gas price data (in units of EUR/MWh) refer to the TTF month-ahead daily futures price (the benchmark gas price of European markets). The coal price data (in units of EUR/tonnes) refer to the ARA month-ahead daily futures price. The appropriate conversion to EUR/MWh is used under the assumption of 8.14 tonnes of coal per MWh. Similarly, the carbon price, which refers to the daily futures price for EU allowances in the EU ETS, is in units of EUR/tonnes CO₂, and converted using an EU-wide average emissions factor of 0.3 gCO₂ per KWh, based on the 2018-2021 average emissions intensity of EU countries. In the policy analysis, we use country-specific emission factors given each country’s electricity generation mix.

Our sample comprises a total of 10,224 hours spanning the time period of April 2021-May 2022. We focus on data from this time period as it reflects a period in which natural gas prices experienced massive exogenous shocks in no small part due to the ramping up and eventual conflict in Ukraine and can thus be treated as plausibly exogenous, before any wholesale market distortive mechanisms were put in place (see Supp. Discussion 1). Hence, this allows us to elucidate electricity generator responses to commodity prices and the environmental impact of the natural gas price crisis. We note that the beginning of our sample period coincides with the late phase of the COVID-19 pandemic, when economic activity and natural gas demand in the EU were still depressed, exerting downward pressure on gas prices. Our analysis therefore spans two distinct crisis episodes with opposing price dynamics: a negative demand shock associated with the late-COVID period and a subsequent positive price shock following the invasion of Ukraine. Given the short time period and the longtime it takes to construct new fossil fuel facilities, it is reasonable to assume that the capacity mix is virtually unchanged. While most countries have near complete datasets for this time period, Finland, Croatia, and Ireland have the most missing data, with a total non-missing dataset of 8,882, 7,981, and 9,974 respectively. The remaining countries have all less than 50 hours of missing data (Extended Data Fig. 5). For the electricity price pass-through regressions, all countries have complete data (Extended Data Fig. 6).

Econometric Model of Coal Responsiveness

We use the aforementioned exogenous variation in prices to run our main regression specification separately for each country from April 1 2021 - May 30 2022 as follows:

$$\begin{aligned}
 CoalGen_{i,t} = & \beta_1^i \left(\frac{Gas_p}{Coal_p} \right)_{i,t} + \beta_2^i \left(\frac{Gas_p}{Coal_p} \right)_{i,t}^2 + \beta_3^i \left(\frac{Gas_p}{Coal_p} \right)_{i,t}^3 + \beta_4^i IRE_{i,t} \\
 & + \beta_5^i Load_{i,t} + \beta_6^i Load_{i,t}^2 + \zeta_{m,i} + \delta_{h,i} + \gamma_{w,i} + \epsilon_{i,t}
 \end{aligned} \tag{1}$$

Our preferred specification utilizes hourly electricity generation and load data, and daily commodity price data. $CoalGen_t$ refers to the log transformed generation of aggregated coal and lignite at any given hour. Our regressor of interest is the price ratio of natural gas to coal, also known as the relative price. The relative price is inclusive of carbon prices, proportional to the amount of CO₂ coal or natural gas (one third of that from coal) emits. In doing so, we implicitly assume that endogeneity between the carbon price and fuel switching is negligible, which is supported by evidence showing that fuel-switching behavior accounts

for only a small share of carbon price variation [45–48] and that carbon prices are largely determined by political and institutional factors affecting allowance supply rather than by contemporaneous emissions demand [29–31]. The cubic form of the relative price is used to allow for the flexibility of generator responses to thresholds of these prices that may experience potential nonlinearities. That is, at a certain price point coal generation may experience changing behavior unexplained by a linear model, due to ramping constraints. This is in line with previous work on coal capacity factor responsiveness to relative prices in the US context [12]. Alternative specifications including only the quadratic or the linear term are included (Supp. Table 14), in which the fit is worse than the cubic form through a larger BIC statistic. At the same time, it remains highly plausible that other functional forms (e.g., fourth or fifth power) could also yield qualitatively similar results and we choose this avenue as it is most in line with the extant literature [12].

Identification is based on month-of-year, hour-of-day, and day-of-week fixed effects, included as ζ_m , δ_h , and γ_w , respectively. We thus rely on within-hour and within-month variation across our sample period and natural gas price shocks due to events outside of the energy sector’s domain. We further control for load (flexibly) and intermittent renewable energy generation (solar, wind, and hydro-run-of-river). To address possible heteroskedasticity and serial correlation in commodity prices and coal generation we cluster standard errors at the level of variation in the treatment variable (natural gas and coal prices), which is daily. We run further robustness checks with different variations of fixed effects, covariates, and functional form, as shown in Supp. Tab. 1-13 for all countries. We further run robustness checks with different time period samples, as shown in Supp. Tab. S16-S19. While most countries show consistent results, few are insignificant when the sample window is shortened before the massive price spikes in 2022, suggesting that a certain relative price threshold was needed to be reached to see the substitution effect.

To validate our choice of standard errors clustering for heteroskedasticity and autocorrelation concerns, the ACF of the regression residuals for each country confirm strong intraday correlation, and the PACF show dependence of the first few lags, in line with operational fuel-switching dynamics and inertia or ramping of coal generation (Supp. Tab. 22-23). An additional check including a lagged regressor of the relative price of the previous day (24 hours before) is included, yielding virtually identical results (Supp. Tab. 20), providing no evidence of delayed fuel-switching adjustments, suggesting that generation decisions respond to contemporaneous fuel prices rather than lagged price signals. An additional robustness check is concluded by running the pooled regression (Supp. Tab. 21) to get an average estimate for all countries, including country fixed effects and thus controlling for any EU-wide shocks. This elasticity estimate (0.21) is significant and similar to the average of the 14 country specific estimates (0.26).

To ease interpretation, we calculate marginal effects using the delta method and present them as the focal estimate of interest. Through this, we are able to estimate the substitution effect for each country i . Specifically, the marginal effect is calculated as:

$$\mu_i = 3 * \beta_3^i * \overline{\left(\frac{Gas_p}{Coal_p}\right)}_i^2 + 2 * \beta_2^i * \overline{\left(\frac{Gas_p}{Coal_p}\right)}_i + \beta_1^i \quad (2)$$

This marginal effect, μ_i , which represents the responsiveness of the coal generation to the relative price of gas and coal, is then multiplied by the average generation of coal and lignite of each country during the sample period (due to the log-scaling) to obtain a value that reflects the change in coal generation per unit of relative price increase. Utilizing the change in relative price for the specified period, we can calculate the change in coal generation in each country at this time (Fig. 2A). Based on the standard emission factors (Lignite as 1100 gCO₂/KWh and hard Coal as 830 gCO₂/KWh), we obtain the induced change in CO₂ emissions (Fig. 2B). The overall increase across our sample of countries is calculated as the sum of excess emissions for our sample countries during this time period. We further calculate the marginal effect $\mu_i h$ at each hour of the day for each country, by including an hourly interaction term (Fig. 3).

Econometric Model of Pass-Through

Pass-through of natural gas prices to wholesale electricity prices in European countries is driven by whether natural gas is the marginal fuel on the merit order system at any given hour. The level of pass-through dictates the change in wholesale electricity price, which in turn influences the studied effects of each policy. Our preferred econometric model of electricity price pass-through is discussed below, based on previous work by quantifying this level of pass-through across European countries during the crisis ([49]). The model regresses hourly electricity prices on daily natural gas prices, with alternative models used to examine the robustness of our estimates (see Extended Data Fig. 6 for main estimates). Each country

is estimated separately to determine the market-wide pass-through of natural gas prices to wholesale electricity prices, as well as for every hour of the day by including an hourly interaction term. Through this, we are also able to calculate the excess electricity price during our sample period, compared to the counterfactual when natural gas prices were at pre-crisis levels (Fig. 2E).

For each country i , we separately estimate the following regression specification:

$$p_{i,t}^{Electricity} = \beta_i^h p_{i,t}^{Gas} + \gamma_{1,i} IRE_{i,t} + \gamma_{2,i} Load_{i,t} + \gamma_{3,i} Load_{i,t}^2 + \delta_{m,i} + \eta_{d,i} + \zeta_{h,i} + \epsilon_{i,t} \quad (3)$$

where hourly electricity price $p_{i,t}^{Electricity}$ is regressed on daily natural gas prices $p_{i,t}^{Gas}$, exogenous controls including hourly intermittent renewable energy generation of solar, wind, and hydro-run-of-river *IntermittentRenewables_t* (dispatchable hydro is not included, since it is endogenous), hourly load $Load_t$ and its quadratic $Load_t^2$, month fixed effects δ_m , hour fixed effects ζ_h , and day-of-week fixed effects η_d (see Supplementary Discussion for an exception of month fixed effects regarding Greece). This is estimated for the period of April 2021-June 2022, with a robustness check of January 2022-December 2022 and January 2021-December 2022 (see Supp. Tab. 21-22).

The coefficients of interest, β^h , that we obtain for each country i are the changes in hourly h wholesale electricity price (EUR/MWh) per 1 EUR/MWh increase in TTF natural gas prices. Month and hour fixed effects are a key control variable as they control for any systematic, unobservable trends over the time sample that may be correlated with gas and electricity prices (e.g. drought, planned nuclear outages). Day-of-week fixed effects η_{dh} similarly control for any systematic, unobservable hourly differences in prices on different days of the week (e.g. weekday vs weekend). Thus, within the same month, on the same day of the week, with the same intermittent renewable energy generation and load, we are statistically comparing two otherwise identical hours, but for the difference in daily gas prices.

Relative Responsiveness Index

To understand the hourly interplay between coal and natural gas usage in each country, we construct an index that relates the hourly coal responsiveness to the hourly natural gas price pass-through coefficients. Specifically, we utilize the Pearson correlation coefficient with the 24 time points for each country, calculated as the covariance of the two estimates, divided by the product of their standard deviations as:

$$\text{Relative Responsiveness} = -\frac{1}{n} \left(\frac{\sum (A_i - \bar{A})(B_i - \bar{B})}{\sqrt{\sum (A_i - \bar{A})^2 \sum (B_i - \bar{B})^2}} \right)$$

whereby A is the hourly coal responsiveness, and B is the hourly pass-through coefficient (the left and center panels of Fig 3. for a subset of countries and Supp. Fig. 20-26 for the rest), and n is the number of observations (24). Intuitively, this is negated to ensure that a more positive score is also a more "responsive" country to the competition between coal and natural gas. A score of 1, which reflects a perfectly negatively correlation, is interpreted either as that country being very reliant on coal to balance out the fluctuations in gas price and prevent electricity prices from rising, or that coal generation does not increase and thus wholesale prices increase. Conversely, a score of -1 can be interpreted as that country using both coal and natural gas at any given hour and the coal is insufficient in preventing prices from rising. Further, a higher relative responsiveness score can suggest that when coal generation does down (e.g., due to a policy such as the one we suggest) wholesale electricity prices are more likely to go up. On the other hand, a low score suggests that coal is not eliminating this vulnerability to higher price. In presence of a gas cap, when coal generation goes down, the price responsiveness effects are diminished.

Policy analysis

We use our estimates of coal responsiveness, μ_i , and pass-through, β_i^h , for each country, to assess the environmental and economic impact of counterfactual policies imposed on natural gas or carbon prices during 2022, as shown in Figure 3. It is important to note that in each of these policy scenarios, we assume that while the cap or tax is imposed all other prices remain the same and are not directly affecting coal or natural gas prices. We subsequently explain the calculation of the responses shown in Figure 5.

First, each policy creates a so-called "substitution effect" of an emissions change from the change in coal generation in response to the relative price of natural gas to coal (Supp. Fig 4). The effect is determined through the responsiveness of coal generation to the relative price based on our estimates for μ_i (Extended Data Fig. 5) and the coal generation of each country. For instance, a cap on the price of natural gas makes

coal relatively more expensive and thus disincentivizes its usage in lieu of the alternative. A certain level of a carbon price can have the same effect, since coal is more emissions intensive and thus a 1 EUR increase in the carbon price makes coal relatively more expensive in relation to natural gas. We determine that equivalent additional carbon tax to be 12.18 EUR/tonnes, through an iterative approach. That is, the *additional* carbon price that would have been needed in 2022 to cause the exact same coal-to-gas switch as the natural gas price would. Specifically, the added price of carbon is found for which the relative price (inclusive of carbon price) during the year of 2022 is equivalent to the average relative price under the hypothetical natural gas cap in this period, as shown in SI Equation (1). The underlying assumptions are the assumed average emission factors of natural gas, in comparison to coal. The iterative approach entails a grid-approach of 10000 points calculating the new relative price with incremental carbon prices (from 0.1 EUR/tonne to 20.0 EUR/tonne) until it equated the relative price under the natural gas price cap in 2022.

Second, each policy induces a change in the wholesale electricity price (Fig. 5C). This is determined through the change in natural gas price multiplied by the level of pass-through of natural gas to electricity prices, β_i^h , (Extended Data Fig. 6). The pass-through of the change in price from carbon is assessed through its impact on the price of natural gas, in which we assume 0.37 EUR/ton CO₂ is passed through for every 1 EUR/MWh of natural gas, given its relative lower emitting nature than coal. Taking Germany (DE) as a numerical example, the natural gas cap reduces the average wholesale price of electricity for 2022 by 13.2 EUR/MWh, while the equivalent carbon tax increases it by 3.2 EUR/MWh, using the pass-through coefficient of the natural gas to electricity price of 1.61 multiplied by the change in natural gas during this period (8.2 EUR/MWh), or the change in carbon tax adjusted via the country-specific emissions factor (2.0 EUR/MWh for Germany after the conversions), respectively.

Third, through the impact on the wholesale electricity price each policy induces demand effects for electricity and thus change in emissions – the so-called "output effect" (Fig. 5B). Intuitively, an increase in the wholesale electricity price will yield a certain reduction in emissions given that a higher price disincentivizes the consumption of electricity. By assuming an average short-run elasticity of demand of electricity price coherent with the extant literature of -0.06, we are able to calculate this effect for each policy, given each country's average emissions factor (the average emissions from an additional KWh generated in each country's grid). Though previous studies for this estimate vary considerably [50–57], we use a conservative estimate, with different assumptions yielding qualitatively similar results (Supp. Fig. 6). Continuing the example of Germany, we arrive at an output effect increase of 712 MWh and -172 MWh respectively for the natural gas cap and the equivalent carbon tax, by multiplying the change in electricity wholesale price (-13.2 or 3.2 EUR/MWh from above) by the elasticity (0.06) and average load (54.96 MWh) and dividing by the average electricity price (236.1 EUR/MWh). This is then converted to emissions from generation using the country specific emissions factor (tCO₂/MWh). The sum of the output and the substitution effect (7580 ktonnes CO₂/year) reflecting the total emissions change for each policy is depicted in Fig. 5A, specifically a reduction of 6867 ktonnes CO₂/year for the natural gas price cap and a reduction of 7752 ktonnes CO₂/year for the carbon levy.

Forth, each policy can induce a relief and burden on consumers (Fig. 5D). This impact is assessed through the change in wholesale electricity price adjusted via each country's average load and country-specific average emissions factor, to obtain units of EUR and allow for appropriate comparisons. That is, a given additional carbon levy will increase the amount of revenue equivalent to the carbon levy (in units of EUR/MWh by adjusting for the average country-specific emissions factor) multiplied by average load (MWh), while similarly burden the country by an additional amount corresponding to the increase in wholesale electricity price multiplied by average load. Continuing the case of Germany, the revenue is equivalent to 12.18 times the average load (54.96 MWh) divided by the emissions factor (0.441 tCO₂/MWh) times 1000 for unit conversions for a total of 1518,000 EUR. The relief is similarly calculated as the average load times the price change under the gas cap times 1000 to convert units, yielding 130,000 EUR for Germany. The burden is calculated as the average load times the price change under the carbon levy times 1000 to convert units, yielding 176,000 EUR for Germany. As shown, approximately 12 percent of the revenue is needed to offset the burden from the increase in electricity price for Germany. On average across countries, this value is just 8 percent, while the relief generated from the natural gas cap is a 32 percent of the value of the revenue.

Data availability

The datasets (.dta files) used and/or generated during the current study are available in the following public repository, https://github.com/ZissisM/EU_EmissionsPenalty.

Code availability

All analyses reported in this study used the statistical software Stata (v. 16.1). All codes (.do files) used for analysis and figure creation are available publicly at https://github.com/ZissisM/EU_EmissionsPenalty.

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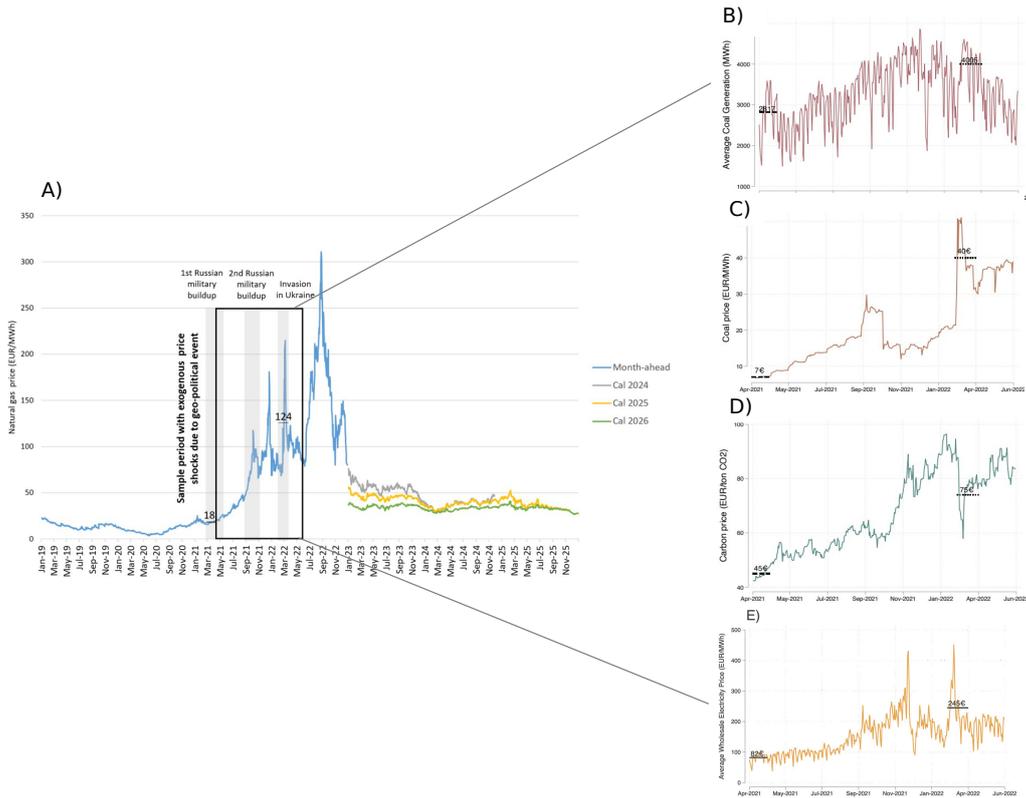


Fig. 1 The spike in natural gas prices in the wake of the Russian invasion to Ukraine and the resultant coal generation, coal prices, carbon prices, and wholesale electricity prices in the EU. The box represents our sample period with plausibly exogenous spikes in natural gas prices triggered by geopolitical events highlighted by gray areas. Each panel highlights average price levels at the beginning and height of crisis, from April 1 2021 to May 30 2022. From the large spikes in natural gas prices one can clearly see the resulting rises in coal generation, carbon price, coal price, and wholesale electricity price. Policymakers thus face two different challenges– mitigating emissions from increased coal generation and mitigating the widespread consequences from increased electricity prices. **A)** Reference prices for natural gas in Europe based on month-ahead futures for natural gas (blue line) and natural gas futures contract with delivery in 2024, 2025, and 2026 (gray, yellow, and green lines) traded at the TTF hub. Prices are interpolated for non-market days. **B)** Average coal generation for our sample of 14 EU countries averaged at a daily level during our sample period. **C)** Coal price based on month-ahead futures (ARA) at the daily level. **D)** Carbon price based on futures for EU allowances (EUAs) in the EU Emission Trading Scheme (EU ETS) traded at ICE ECX at the daily level during our sample period. **E)** Average wholesale electricity price for our sample of countries averaged at a daily level during our sample period.

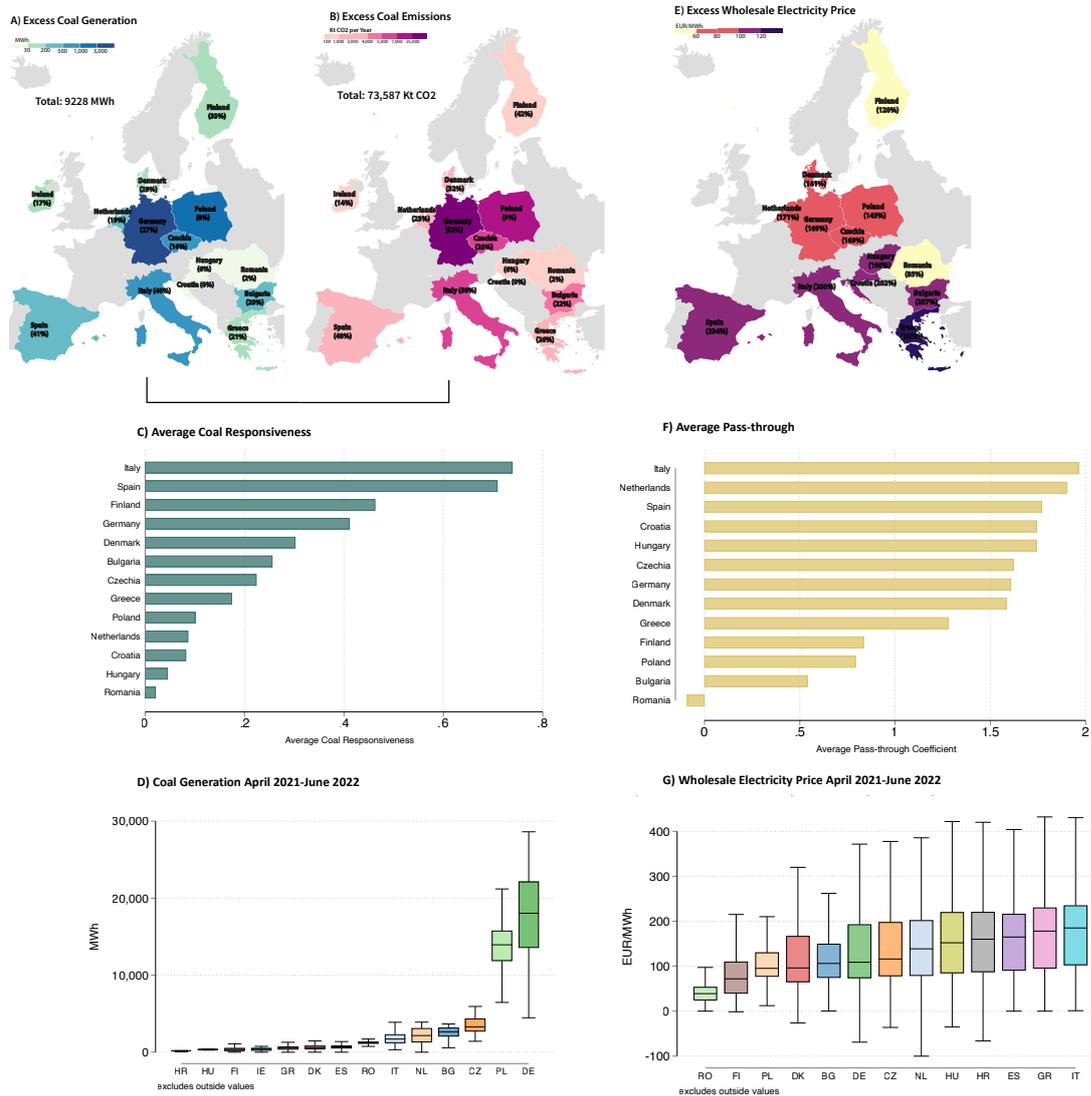


Fig. 2 Excess Emissions and Electricity Price from natural gas price surge. The crisis created two different paths of vulnerability: excess emissions and excess wholesale electricity prices. We estimate the responsiveness of coal generation to the relative price of natural gas to coal and the price pass-through of natural gas to wholesale electricity price (see Methods), allowing us to quantify the excess CO₂ emissions and wholesale electricity price induced by the gas price surge across EU countries during the 2021/2022 crisis (see Extended Data Fig. 5 and 6 for point estimates). **A)** Excess coal and lignite generation during April 1 2021 - May 30 2022. This refers to the additional amount of coal generated in surplus of the predicted coal under "non-crisis price environment." This is calculated by subtracting the estimated amount of coal generated under counterfactual scenario where relative gas prices are equivalent to the pre-crisis period January - March 2021 (a price ratio 34% lower during this period at 1.25 as opposed to 1.88; see Supp. Fig for excess calculations using alternative baselines) – from the actual observed coal generation (panel D). The relative percentage increase is compared to this pre-crisis period as a baseline. **B)** The excess carbon emissions generated from excess coal generation depicted in panel A, using standard emission factors for lignite and hard coal (see Methods). **C)** Average coal responsiveness estimates per country during April 1 2021-May 30 2022, as seen in Extended Data Fig. 1. **D)** Average coal generation per country during April 2021-June 2022, with vertical box plots capturing the $\pm 1.5 \times \text{IQR}$ (the interquartile range) with bounds at the 25th percentile (Q1) and 75th percentile (Q3). The center line of the box represents the median (50th percentile). Whiskers extend to the smallest and largest values within $1.5 \times \text{IQR}$ of the lower and upper quartiles, respectively. See Supp. Fig. 17 for same panel excluding the outliers Germany and Poland. **E)** Excess wholesale price during April 2021-May 2022. This refers to the additional price of electricity in surplus of the predicted price under a "non-crisis price environment." This is calculated by subtracting the estimated wholesale electricity price predicted under a counterfactual low gas scenario (price from January-March 2021) using the country pass-through estimates (panel F) from the actual observed wholesale price (panel G). **F)** Average price pass-through estimates per country during April 2021-May 2022, as seen in Extended Data Fig. 2. **G)** Average wholesale electricity price per country during April 2021-June 2022, with vertical box plots capturing the $\pm 1.5 \times \text{IQR}$ (the interquartile range) with bounds at the 25th percentile (Q1) and 75th percentile (Q3).

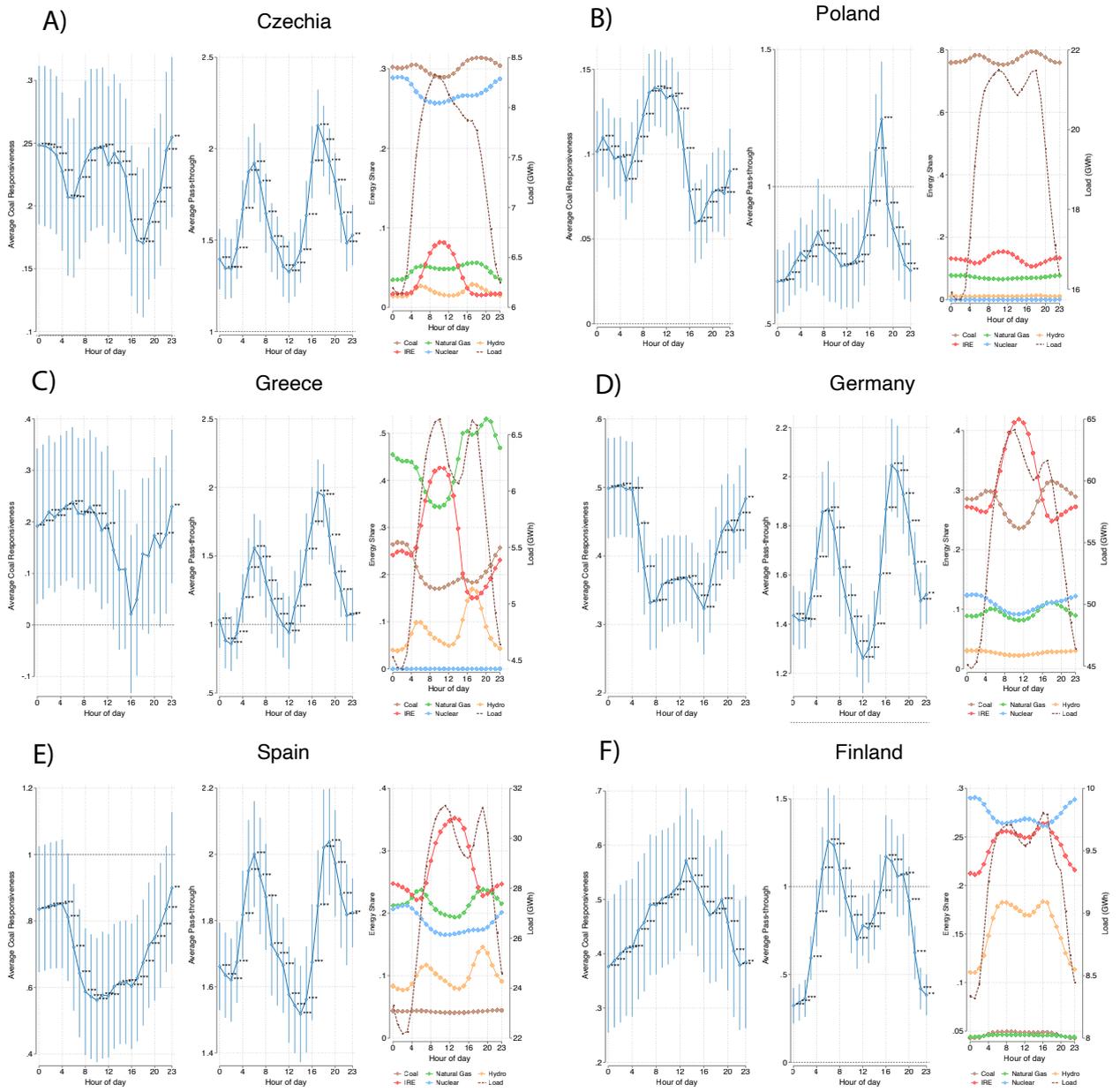


Fig. 3 Channels of adjustment suggested by hourly coal responsiveness, natural gas price pass-through, and energy shares for six representative countries. A) - F) Estimated hourly coal responsiveness (left panels), estimated pass-through coefficients by hour (middle panels) and the average share of different generation technologies used by hour (right panels) for the following countries: Czechia, Poland, Greece, Germany, Finland and Poland, using our main specifications for each country (Extended Data Fig. Figure 5 & 6) while including an hourly interaction term with our regressor of interest. These countries were selected to highlight the varying nature of the interrelationship between coal responsiveness and price responsiveness, while also providing geographic diversity. For each country, dots in the first two panels represent the estimated hourly coal responsiveness or pass-through coefficients respectively, while the vertical lines capture 95% confidence intervals (± 1.96 times the standard error of each point estimate). The statistical test used is a two-sided t-test. The coefficients that are statistically distinct from either 0 or 1 at the 1% or 5% significance level are indicated with three stars or two stars, respectively. In the right panel, “intermittent renewable” includes solar, wind, and hydro-run-of-river. The dashed line displays the average hourly load. The exact sample size for each country is depicted in Extended Data Fig. 5 & 6. For the remaining country-specific figures see Supplementary Fig. 20-26.

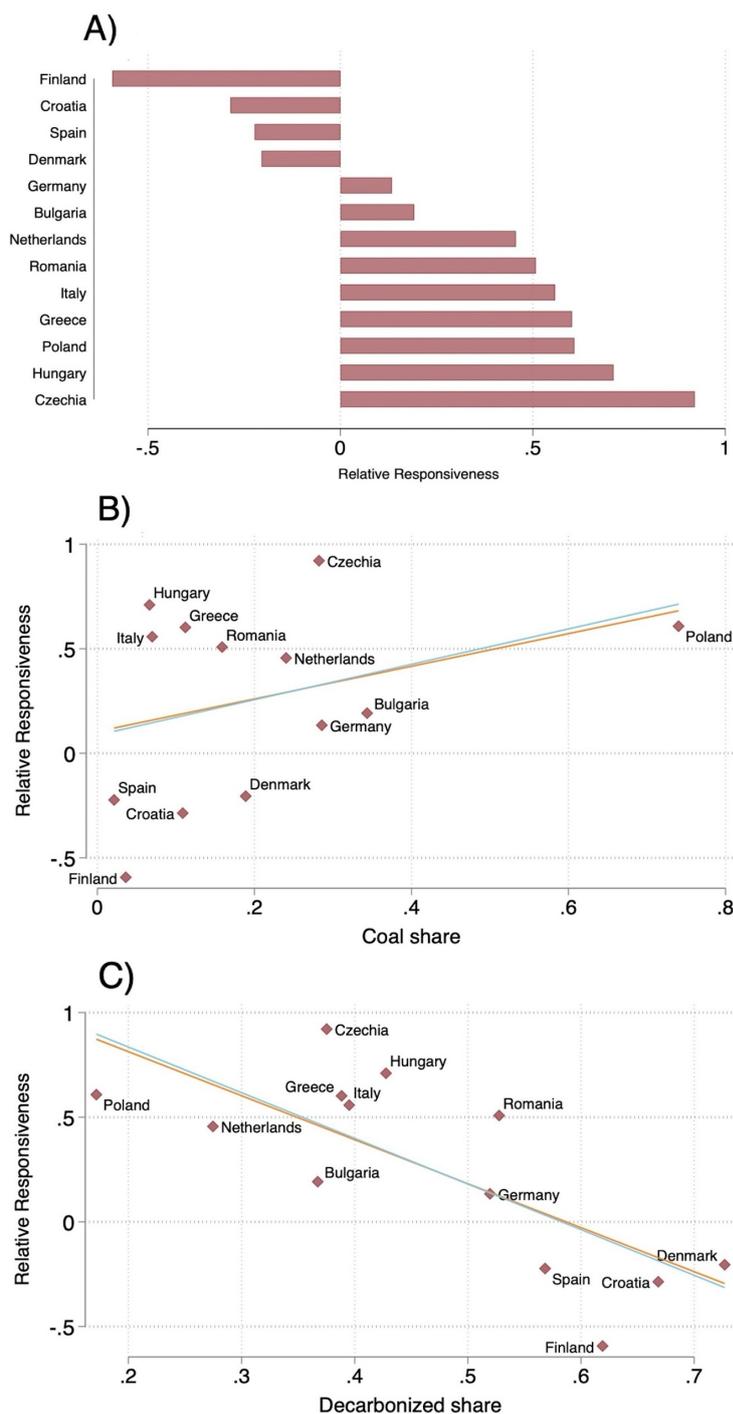


Fig. 4 Relative Responsiveness Index reflecting trade-off between gas-to-coal switch and higher electricity price. For each country separately, a relative responsiveness score is calculated based on the hourly estimates of each responsiveness. **A)** Score of relative responsiveness for all countries. This is defined as the negated Pearson correlation coefficient between the 24 hourly estimates of coal responsiveness and price pass-through (as depicted in Figure 3A and 3B for a subset of countries; see Methods for more information on the index calculation). The higher the relative responsiveness score, the more negatively correlated coal responsiveness and natural gas price pass-through to electricity are. As such, it indicates that this country is reliant on coal to balance out the fluctuations in natural gas prices and keep electricity prices from rising. This is in contrast to a negative score, which suggests that coal generation is insufficient to stop the electricity price from increasing. **B)** Correlation between relative responsiveness and share of coal in electricity production. A higher coal usage is correlated with a higher score. **C)** Correlation between relative responsiveness and share of decarbonized electricity production (solar, wind, hydro, and nuclear energy). A higher decarbonized energy share is correlated with a lower score. Breaking down the decarbonized share, a higher hydro or wind share is correlated with a lower score, while nuclear and solar have a slight positive correlation (Extended Data Fig. 4). Scatter plots include a fitted line of a linear regression estimated via OLS (blue line), and a fitted line estimated using the robust MM-estimator (orange line). The robust MM-estimator is preferred when the data has outliers and likely-influential but non-representative points [21].

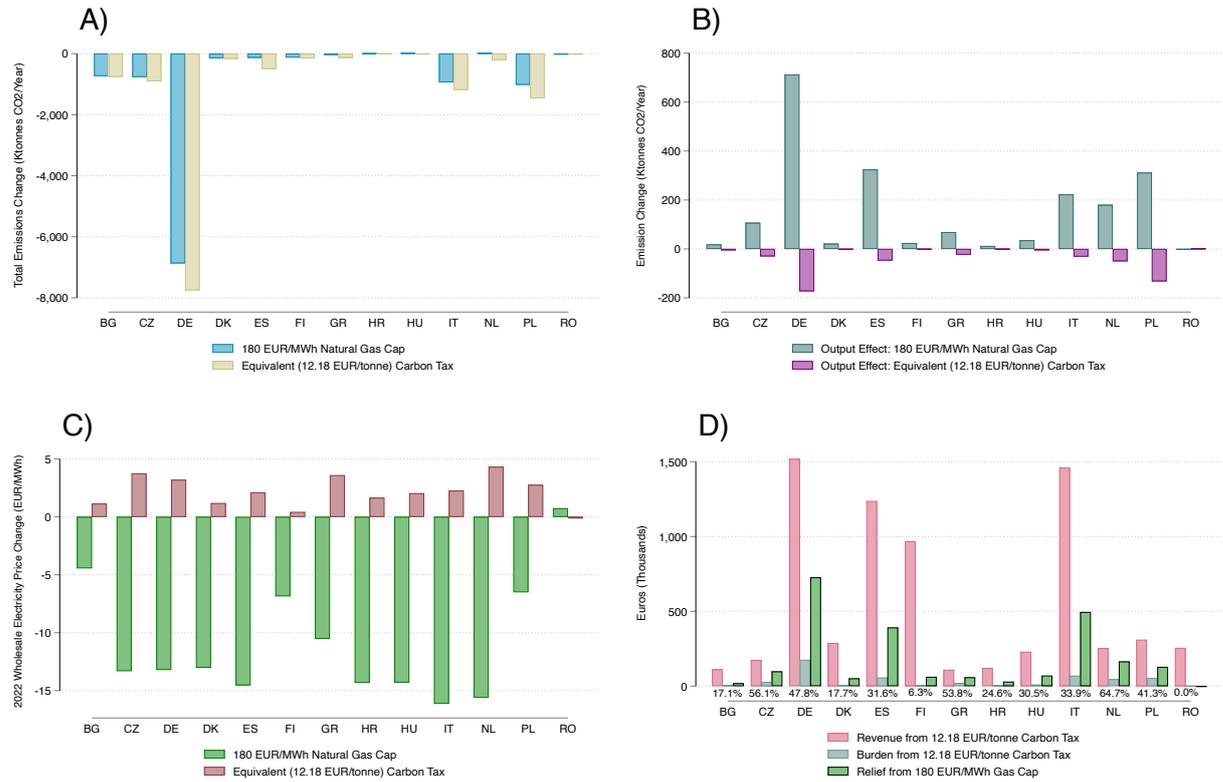
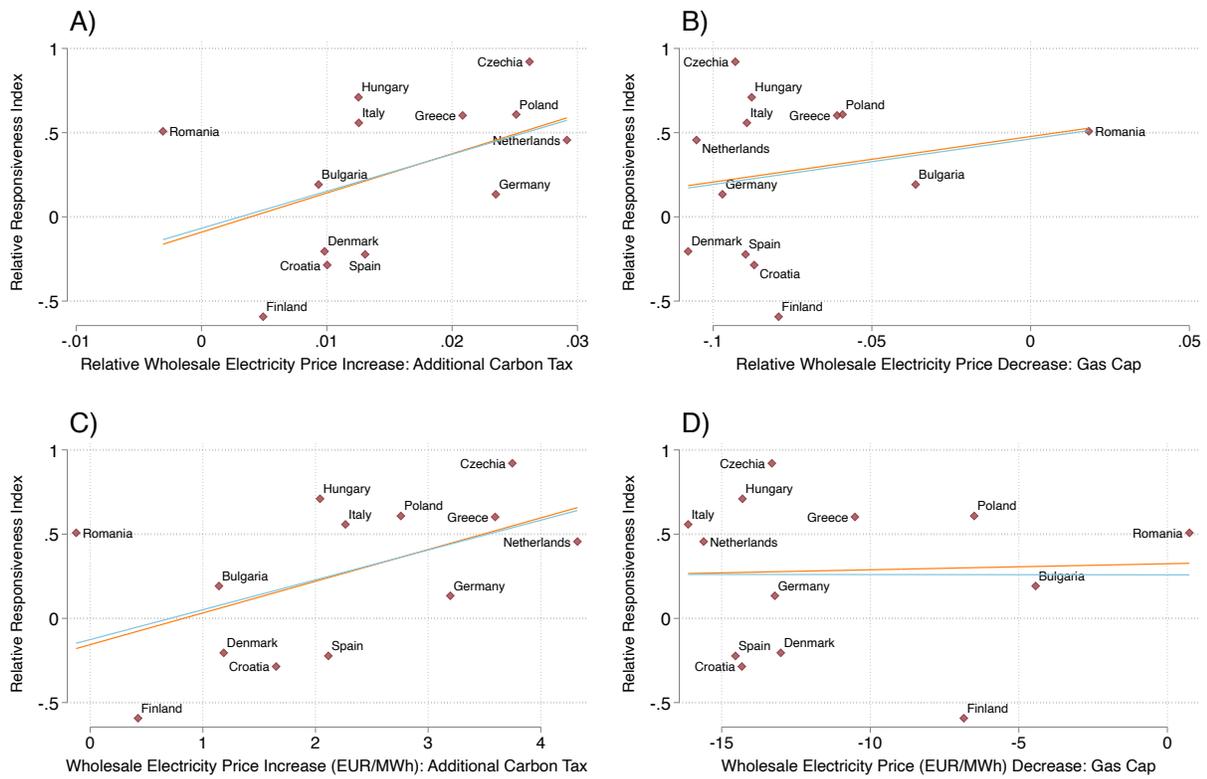
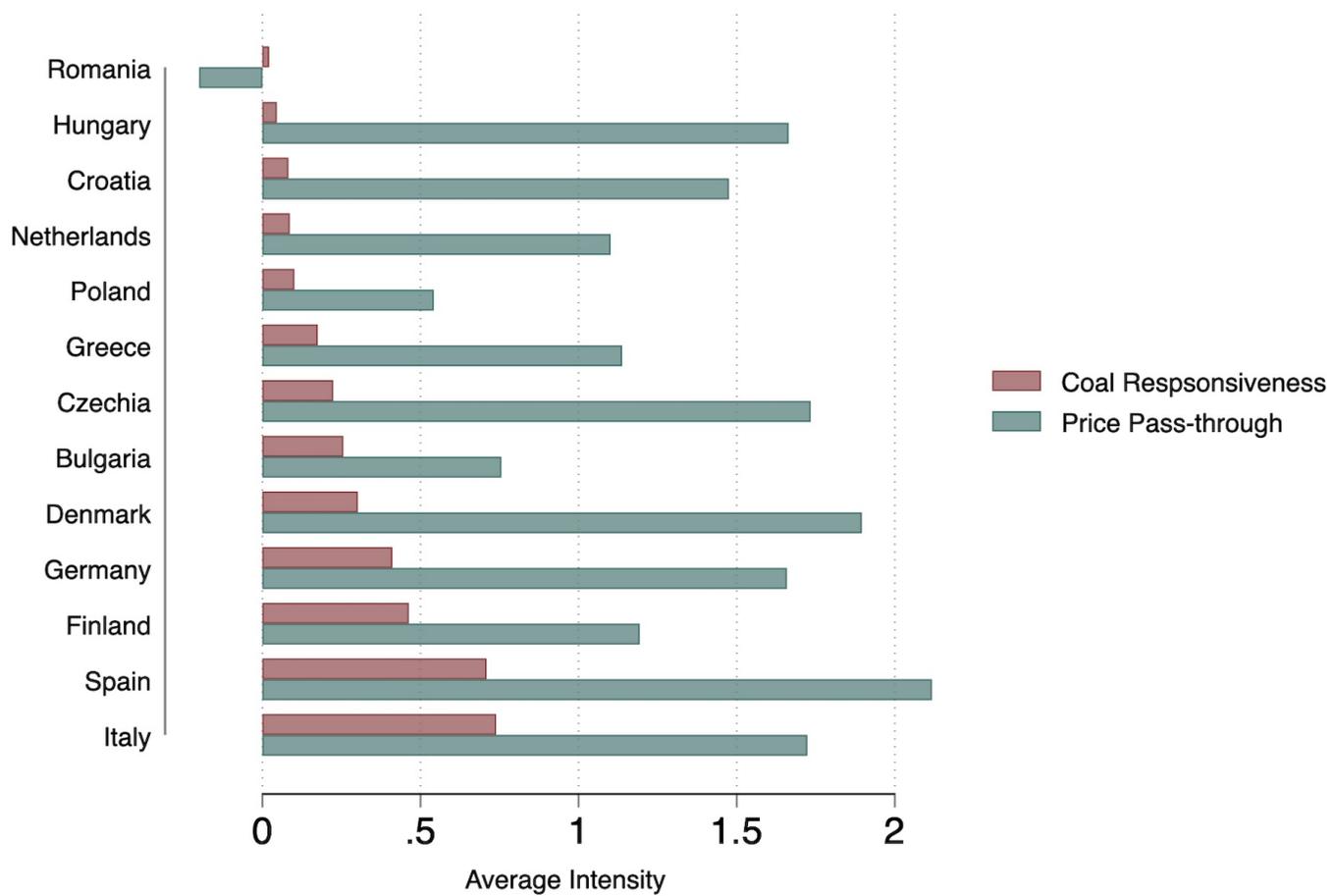


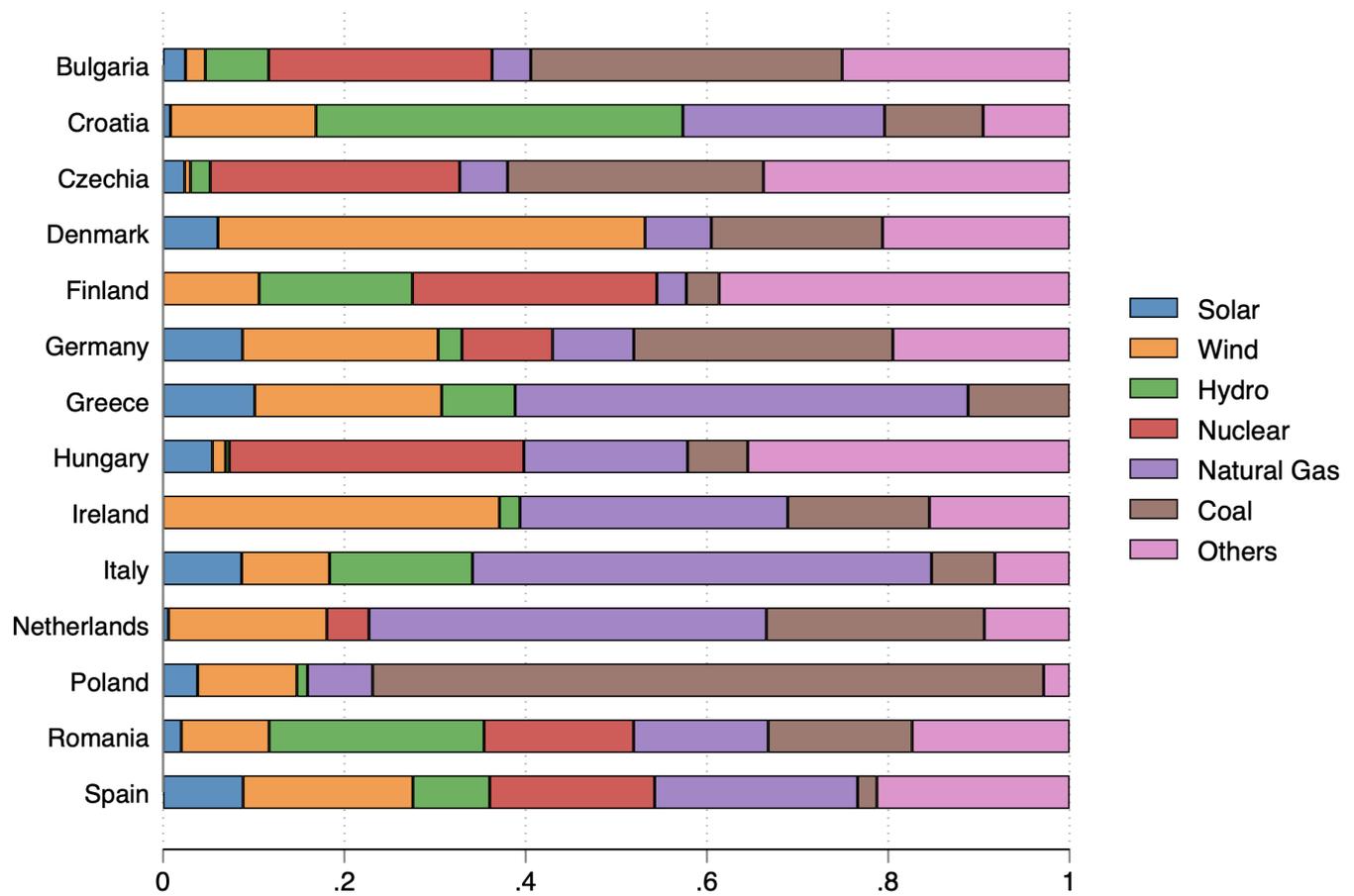
Fig. 5 Policy counterfactual analysis comparing the gas price cap (180 EUR/MWh) and the substitution-equivalent carbon price (12.18 EUR/tonne) over the period January 2022-December 2022. Equivalent carbon price represents the additional price that would generate the same substitution effect that the cap on the price of natural gas yields during 2022. **A)** Comparison of total emissions change under each policy per country, including the substitution and output effect. **B)** Comparison of underlying output effect and substitution effect under each policy per country. The output effect per country is calculated using electricity price pass-through estimates and assumed elasticity of demand (-0.06), based on prior literature, while Supplementary Fig. 6 provides alternative estimations based on lower and higher assumptions. **C)** Comparison of wholesale electricity price change under each policy using our pass-through estimates (see Methods). Pass-through under the equivalent carbon price is assumed to work via the corresponding increase in natural gas price, and we assume it remains unchanged aside from the increase in corresponding carbon price (see Supp. Fig. 8 for changing assumption of carbon price pass-through to electricity price). **D)** Comparison of the change in revenue and financial burden and relief of each policy per country. For the gas price cap, the relief that results from the policy-induced lowers electricity prices. For the equivalent carbon price, the burden from the additional carbon pass-through and the revenues that could be used for consumer relief is shown. The revenue is significantly greater than the relief provided by the natural gas cap, as seen in the percentage value shown under each country’s bars which shows the share of revenue left after covering the relief from the gas cap. All values are normalized by average load per country, while the revenue and burden are adjusted with country specific emissions factors.



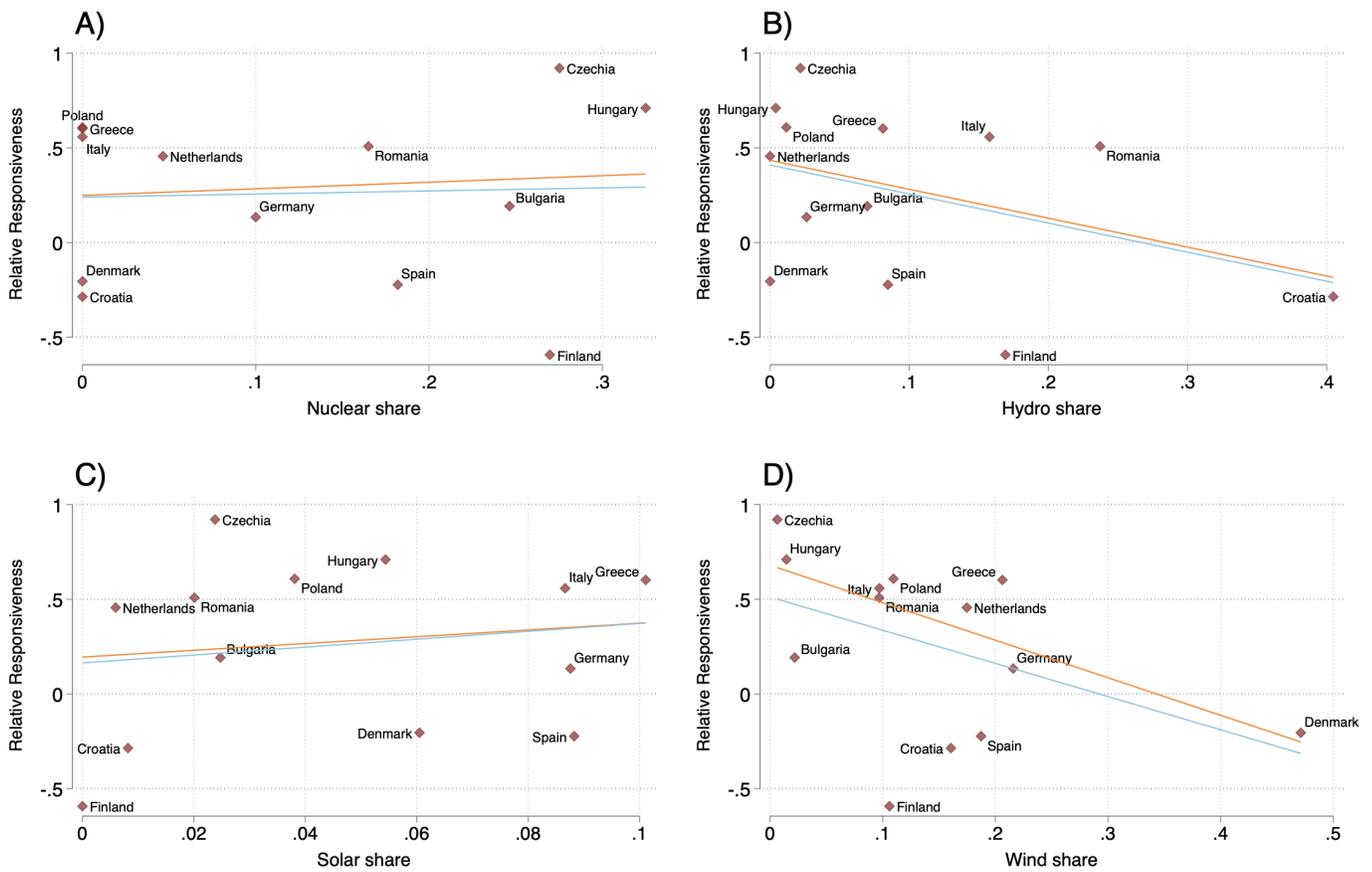
Extended Data Fig. 1: **A)** Relationship between the relative responsiveness index and the relative wholesale price change (compared to a pre-crisis baseline price) under an additional carbon tax (12.18 EUR/tonne), during 2022. **B)** Relationship between the relative responsiveness index and relative wholesale price change (compared to a pre-crisis baseline price) under 180 EUR/MWh Gas Cap, during 2022. **C)** Relationship between the relative responsiveness index and the wholesale price change under an additional carbon tax (12.18 EUR/tonne), during 2022. **D)** Relationship between the relative responsiveness index and wholesale price change under 180 EUR/MWh Gas Cap, during 2022.



Extended Data Fig. 2: Average intensity (regression coefficients) of coal responsiveness and natural gas price pass-through for all countries during our sample period.



Extended Data Fig. 3: Illustration of the energy generation mix for all countries during our sample period. Coal refers to both hard coal and lignite, as used in our analysis, while Hydro refers to both dispatchable and run-of-river.



Extended Data Fig. 4: Relationship between relative responsiveness and breakdown of decarbonized energy sources. A) Relationship between the relative responsiveness index and the nuclear energy generation share. B) Relationship between the relative responsiveness index and the hydro energy generation share. C) Relationship between the relative responsiveness index and the solar energy generation share. D) Relationship between the relative responsiveness index and the wind energy generation share.

VARIABLES	(1) BG	(2) CZ	(3) DE	(4) DK	(5) ES	(6) FI	(7) GR	(8) HR	(9) HU	(10) IT	(11) IE	(12) NL	(13) PL	(14) RO
Relative Price	1.959*** (0.244)	1.279*** (0.280)	2.431*** (0.307)	1.277** (0.541)	4.605*** (0.592)	3.269*** (0.460)	-0.244 (0.855)	0.455 (0.401)	0.092 (0.270)	4.324*** (0.603)	-2.109*** (0.759)	-1.883*** (0.642)	0.589*** (0.078)	0.135 (0.194)
Intermittent Renewables (GWh)	-0.150*** (0.019)	-0.055*** (0.017)	-0.024*** (0.001)	-0.157*** (0.010)	-0.025*** (0.004)	-0.063*** (0.018)	-0.064*** (0.024)	-0.066*** (0.023)	0.059** (0.026)	-0.040*** (0.005)	-0.335*** (0.016)	-0.110*** (0.012)	-0.054*** (0.001)	-0.055*** (0.006)
Load (GWh)	0.311*** (0.045)	0.123*** (0.044)	0.075*** (0.008)	0.086 (0.161)	0.047 (0.035)	0.696*** (0.122)	0.455*** (0.087)	0.248** (0.118)	0.168** (0.077)	0.043** (0.019)	0.083* (0.050)	0.265*** (0.023)	0.135*** (0.009)	0.430*** (0.044)
Load Squared (GWh)	-0.019*** (0.004)	-0.001 (0.002)	-0.000*** (0.000)	0.014 (0.016)	-0.001 (0.001)	-0.021*** (0.005)	-0.011* (0.006)	-0.036 (0.023)	-0.006 (0.007)	-0.000 (0.000)	0.013 (0.010)	-0.010*** (0.001)	-0.002*** (0.000)	-0.023*** (0.003)
Observations	10,223	10,224	10,224	10,223	10,193	8,882	10,213	7,981	10,210	10,224	9,974	10,206	10,224	10,173
R-squared	0.896	0.782	0.809	0.555	0.547	0.825	0.390	0.209	0.143	0.532	0.630	0.732	0.911	0.492
Month FE	YES	YES	YES	YES	YES	YES	YES							
Hour FE	YES	YES	YES	YES	YES	YES	YES							
Day of Week FE	YES	YES	YES	YES	YES	YES	YES							
Marginal Effect	0.259	0.224	0.411	0.302	0.705	0.463	0.179	0.0836	0.0454	0.747	0.0295	0.0868	0.103	0.0206
SE	Day Clustered	Day Clustered	Day Clustered	Day Clustered	Day Clustered	Day Clustered	Day Clustered							

Extended Data Fig. 5: Estimates of main regression results of responsiveness of log-transformed coal generation factor to relative price (natural gas price/coal price). The marginal effect, which is the estimate of interest, is derived through the delta method from the relative price coefficients, using the mean value of relative price during our sample period. The statistical test used is the two-sided t-test. * indicates significance at the 10% level, ** indicates significance at the 5% level, and *** indicates significance at the 1% level.

VARIABLES	BG	CZ	DE	DK	ES	FI	GR	HR	HU	IT	NL	PL	RO
Natural Gas Price	0.540*** (0.047)	1.621*** (0.075)	1.608*** (0.062)	1.584*** (0.067)	1.770*** (0.065)	0.834*** (0.075)	1.280*** (0.108)	1.744*** (0.068)	1.741*** (0.073)	1.964*** (0.072)	1.900*** (0.052)	0.792*** (0.068)	-0.090*** (0.029)
Intermittent Renewables (GWh)	-43.011*** (5.699)	-54.841*** (4.808)	-4.407*** (0.136)	-28.461*** (1.309)	-4.745*** (0.345)	-20.316*** (2.137)	-15.996*** (1.764)	-15.998*** (6.393)	-17.658*** (5.669)	-5.120*** (0.547)	-17.302*** (0.925)	-11.296*** (0.672)	-4.824*** (0.645)
Load (GWh)	-29.351* (16.339)	-54.756*** (9.468)	-0.341 (1.004)	-108.089*** (19.643)	6.098* (3.457)	-153.195*** (23.157)	7.571* (4.516)	-34.895 (33.422)	-95.075*** (18.464)	4.113*** (1.195)	25.851*** (4.664)	-20.057*** (5.123)	-12.386*** (1.376)
Observations	10,224	10,224	10,224	10,224	10,224	10,224	10,224	10,224	10,224	10,224	10,224	10,224	10,224
R-squared	0.778	0.780	0.873	0.753	0.877	0.638	0.817	0.842	0.831	0.902	0.829	0.721	0.603
Month FE	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES
Hour FE	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES
Day of Week FE	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES

Extended Data Fig. 6: Estimates of the main regression results of natural gas price pass-through to wholesale electricity prices for all countries during our main sample period. The Natural Gas price coefficients represent the impact of an increase in the price of natural gas (in EUR/MWh) on the wholesale electricity price (in EUR/MWh) for each country. The statistical test used is a two-sided t-test. * indicates significance at the 10% level, ** indicates significance at the 5% level, and *** indicates significance at the 1% level. Standard errors are clustered at a daily level. See Supplementary Discussion 1.2 for missing country exception.

Supporting Information for "Emergency Response Mechanisms for addressing challenges with high prices in international energy markets"

March 5, 2026

Contents

- 1 Supplementary Discussion 2**
- 1.1 Electricity and Commodity markets 2
- 1.2 Dataset and sample 4
- 1.3 Robustness Checks 5
 - 1.3.1 Econometric Model of Coal Responsiveness 5
 - 1.3.2 Econometric Model of Pass-Through 33
 - 1.3.3 Relative Responsiveness Index 35
 - 1.3.4 Policy analysis 38

- 2 Supplementary Figures 44**

1 Supplementary Discussion

1.1 Electricity and Commodity markets

In this supplementary discussion we provide additional information on natural gas, coal, and wholesale electricity markets in Europe.

Natural Gas Markets Prior to the nineties, natural gas markets across Europe were heavily regulated by government-owned and controlled firms. The next decade resulted in a series of market liberalizations and deregulations, culminating in the European Union directive in 1998 (98/30/EC), eventually creating multiple trading hubs across the nation where market participants act to set a price and delivery dates for natural gas. Several legislative actions further strengthened competition across the EU, bolstering the requirements meant to disentangle the supply from distribution of natural gas [[Broadstock et al., 2020](#), [Heather, 2021](#)].

Since the early 2010s, the Dutch Title Transfer Facility (TTF) hub has grown substantially to become the leading hub in Europe (surpassing the British National Balancing Point) and become one of the global pricing benchmarks for natural gas alongside the Japan Korea Marker (JKM) and US Henry Hub [[Heather, 2021](#)]. Due to its proximity to storage facilities and important port terminals, it proved to be the most connective to other European ports and markets. The TTF is priced in EUR/MWh, which traders prefer to pence/therm that is done in NBP contracts [Heather \[2020\]](#).

The physical infrastructure between and within countries determines the level of natural gas connectivity and the ease of arbitrage between prices at different locations. While natural gas pipelines were the main methods of transportation, re-gasification terminals have been increasing in number due to the rising popularity of LNG. Price differences at all European Hubs with sufficient trading volume are minimal and usually the cost of transportation; even more so, these differences are decreasing due to the development of swap contracts between gas shipping traders. As such, these hubs are strongly correlated and increasing convergent [[Neumann and Cullmann, 2012](#), [Asche et al., 2013](#), [Heather, 2016](#), [Garaffa et al., 2019](#), [Broadstock et al., 2020](#), [Jotanovic and D'Ecclesia, 2021](#)]. Most European natural gas has historically been sourced from Russia and Norway via physical pipelines. Following the onset of the war, from summer 2022 on (i.e. outside of our estimation sample period), Norway and other suppliers such as Algeria and the United Kingdom have increased their supply flow to European countries, while countries such as the US and Qatar have exponentially increased their sales of liquid natural gas to make up for this lack of supply.

The pricing of natural gas is thus determined on these international hub markets that are often results of not only demand and supply forces, but also market speculation of traders. As such,

geopolitical events in that may rattle markets or actors that supply natural gas can greatly impact the price. While actions of a significant market seller of natural gas can evidently affect the price of natural gas (i.e., Russian army buildup and invasion of Ukraine), it is also true that any geopolitical tension in proximity to these actors can also induce volatile and price spikes (i.e., sociopolitical instability in Israel and Gaza). Importantly, these massive price fluctuations are often due to exogenous factors, unrelated to the workings of the natural gas market. Most relevant to the period of our paper, Russia disrupted EU gas supplies starting in Q3 2021 through Gazprom not refilling gas storage sites and randomly interrupting deliveries via pipelines such as Nordstream. Our empirical strategy exploits these geopolitical events that induce exogenous variation in gas prices to estimate key response mechanisms for policy analysis.

In particular, we use the TTF month-end futures prices, which are most used by gas-fired generators to hedge the spark spread risk [Martínez and Torró, 2018]. These prices are thus the ones most observed by market participants and used to determine the profit margin earned by buying natural gas and producing electricity [Emery and Liu, 2002, Spodniak and Bertsch, 2020]. Furthermore, futures prices are shown to be more reactive to market information than spot prices, since the futures market is easily accessible to financial traders, without interest in physical delivery [Silvapulle and Moosa, 1999, Bohl et al., 2011, Nick, 2016]. As such, short-term (month) futures provide the most valid price signals, while spot prices are often impacted by unpredictable short-run conditions against which generators are hedged via future trading Nick [2016].

Coal markets Since before the inception of the European Union, coal has been at the forefront of European markets. The European Coal and Steel Community (pre-cursor of the European Union) set the foundations of European integration and economic cooperation. Today, the most liquid and utilized coal hub is the Amsterdam Rotterdam Antwerp (ARA) hub, imported through Northwestern Europe. This is the largest derivative market for coal, referring to steam coal that takes into consideration the international transportation costs (CIF, Cost Insurance and Freight) [Sribna et al., 2019]. The prices set at this hub are used as a benchmark for European generators, and thus these prices reflect the fuel cost utilized in electricity production under hard coal. The units for this price are in USD/metric tonne, and thus we convert to EUR/MWh based on an assumed heat rate and conversion factor of tonnes to MWh of 8.14. Similarly to the TTF hub gas prices, month-end futures are the most liquid contract on the market. In contrast to the natural gas markets, coal markets are much less volatile. Lignite is not traded on these markets as much of it is sourced in place, but generally follows the coal benchmark prices.

Though to a lesser extent than natural gas markets, European coal prices are affected by international geopolitical conditions, such as the Russian invasion of Ukraine, or even supply constraints in major producers and exporters, such as Australia or Indonesia.

Electricity markets Prior to liberalization reforms in European markets, each country's power sector operated according to its own rules under heavy regulation consisting of vertically-integrated utilities responsible for generation, transmission, distribution, and retail of electricity. European Union directives prompted this liberalization by creating competitive wholesale markets with numerous private generators in lieu of vertically integrated monopolies [Roggenkamp and Boisseleau, 2005, Glachant and Perez, 2011]. Furthermore, it created common rules for countries to allow for integration towards a single power market. While the current state of integration is far from perfect, the foundations in place allow for the partial interconnection of electricity across borders.

Most importantly, the common framework led to the creation of the day-ahead and intraday electricity markets [EU4Energy Initiative, 2022]. The day-ahead market consists of generators bidding for electricity at a specific hour of the day of the following day, under different demand forecasts, while the intraday market allows for balancing bids to the deviations in supply and demand from the day-ahead forecasts. While the intra-day market is essential to match supply and demand at all times of the day, the day-ahead market primarily acts to set the wholesale electricity price as it is directly impacted by the price of fuels used by generators that participate, which is why it remains the focal point of most paper analyses (including this one).

Every noon, an auction is held to determine the quantities and prices of electricity supplied for the next 24 hours the following day. Generators bid the price in EUR/MWh at which they are willing to supply a quantity of electricity at a given time, determined by its operational cost (mainly consisting of fuel costs and emissions costs). The market operator matches each generators' bids to the supply of electricity, creating the merit order, which essentially reflects the ascending order of costs of fuels of the different generators. Thus, the lower-bidding (and hence lower marginal cost) generators are dispatched first (e.g., intermittent renewables, nuclear, etc.). The intersection of the supply curve of generators with the forecasted demand sets the wholesale electricity market-clearing price for each hour of the day. The last, and most expensive, generator dispatched at each hour is termed the "marginal generator," as it sets the market price due to the uniform-price auction. Thus, all generators, including those with much less marginal costs, are paid the exact same price for electricity supply. Given that the fuel cost is often the prime determinant of bids, the wholesale market price of electricity is highly dependent on these commodity prices, such as natural gas. Thus, the composition of the electricity mix is another determinant of a market's level of pass-through of natural gas prices to electricity prices.

1.2 Dataset and sample

The data on hourly wholesale electricity prices, load, and generation were collected via API from ENTSO-E, which covers European Transmission System Operators (TSO) across 35 European

countries. A unique API key was obtained to download these data for 14 EU countries using the EntsoePandas Python client and appropriate zone codes (EIC) outlined on their website ¹ Electricity generation sources used include natural gas, hard coal, lignite coal, nuclear, solar, wind, and hydro-run-of-river. As mentioned in the Methods, Irish electricity prices could not be obtained and thus Ireland is only analyzed during the first part of our paper (Fig. 2). Settlement prices of futures for natural gas, coal, and carbon allowances in the EU ETS were obtained from Thomson Reuters Eikon. For days in which these prices are unavailable due to market closures, the previous day closing value is used, which reflects the appropriate market opportunity cost of using the fuel that the point in time. All commodities are converted to EUR/MWh for calculations (see Methods).

Our sample period for this study was chosen as April 1 2021 to May 31 2022, as it best reflects the onset of the natural gas price shock from the Russian army buildup of preparation of the Ukraine invasion, up to three months after the invasion in which governments started enacting policies that would confound commodity and wholesale markets. For one, the REPowerEU package, meant as an EU-wide comprehensive response to the crisis, was proposed in May 2022. Proposals such as the natural gas price cap, were meant to be implemented starting early 2023. While various initiatives were proposed earlier by national governments, they are primarily targeted towards shielding and relieving consumer retail bills, as opposed to wholesale markets. Almost all countries provided some form of partial retail price compensation to companies and households, as well as VAT reduction, starting December 2021, but sought not influence the wholesale market. Specifically, many countries targeted vulnerable households for subsidies. It was not until the summer of 2022 that talk of capping prices in the wholesale market was pronounced (with some countries eventually adopting windfall taxes on energy producers or wholesale electricity price caps). A key example is the so-called "Iberian exception", which came into place during the summer of 2022 and essentially capped natural gas, and thus wholesale electricity prices.² Thus, during this period we can plausibly justify the natural gas price spikes to be exogenous. For robustness checks of different sample periods see Supp. Tab 15.

1.3 Robustness Checks

1.3.1 Econometric Model of Coal Responsiveness

We conduct a series of robustness checks to verify the validity of our results. In terms of our main regression for the responsiveness of coal generation to the relative gas price, Supp. Tab. 1-13 illustrate the marginal effect estimates with different specifications for each country, such as the

¹https://transparency.entsoe.eu/content/static_content/Static%20content/web%20api/Guide.

²For a comprehensive list of policies enacted by countries see: <https://www.bruegel.org/dataset/national-policies-shield-consumers-rising-energy-prices>

addition of monthly fixed effects, day-of-week and hourly fixed effects, the inclusion of covariates such as load, intermittent renewables, and nuclear energy generation, as well as the clustering of standard errors, to arrive at our preferred specification in column (5). Importantly, while the inclusion of these control variables has a noticeable (though qualitatively similar) impact on the magnitude of the coefficient in most countries, the inclusion of monthly fixed effects (column 4) is shown to have the largest impact on the estimates for most countries, with the largest differences in the Netherlands (Supp. Tab. 11), Ireland (Supp. Tab 9), and Croatia (Sup. Tab. 2) . Since a threat to our estimation strategy could be unobservable variables that are potentially correlated with both coal generation and commodity prices and trending over time, month fixed effects restrict our identifying variation to be strictly within a month. For example, we statistically allow comparisons between prices on June 7 and June 20, but not between September 5 and August 6. ³ Clustered errors yields qualitatively similar results as robust standard errors, with the exception of Croatia and Romania (Supp. Tab. 12). Furthermore, using Newey standard errors yields qualitatively similar results to our main specification of clustering standard errors by day, which is the unit of variation of the treatment variable (natural gas and coal prices). To validate our choice of standard errors clustering for heteroskedasticity and autocorrelation concerns, the ACF of the regression residuals for each country confirm strong intraday correlation, and the PACF show dependence of the first few lags, in line with operational fuel-switching dynamics and inertia or ramping of coal generation (Supp. Tab. 22-23). An additional check including a lagged regressor of the relative price of the previous day (24 hours before) is included, yielding virtually identical results (Supp. Tab. 20) .

We further conduct robustness checks for the sample period analyzed with the main estimates for each subperiod shown in Supp. Tab. 15. Specifically, we shorten the time period in four different ways (Supp. Tab 16-19). While our results remain qualitatively similar across all subperiods, certain countries (Czechia, Denmark, Spain, Finland) exhibit a significant responsiveness effect only during the entire sample period, which may indicate that in these countries either certain thresholds of the relative price need to be reached in order to see a substitution effect, or that these thresholds were already reached and there is no significant substitution change observed during the smaller subsamples. On the other side, Hungary is shown to have significant responsiveness effect for all smaller subsamples but not the full sample, which may indicate idiosyncrasies or confounders in the Hungarian market that obstruct us from observing the desired estimate. Never-

³An exception to the month fixed effects approach is Greece, where (in contrast to the rest of Europe) a smoothing price mechanism based on the average price of the previous month's TTF price is applied (see <https://www.rae.gr/anakoinoseis/31535/> and <https://www.kathimerini.gr/economy/562016074/sta-ypsi-oi-times-toy-fysikoy-aerioy-gia-olo-to-2023/>). As such, month fixed effects would absorb all the meaningful variation in natural gas prices, and so we instead use a linear time trend to control for any spurious unobserved trends. This is also done for the econometric model of natural gas price pass-through.

theless, our full sample period reflects a plethora of relative price variation that allows us to uncover the substitutability of these countries, with most countries showing qualitatively similar patterns. Lastly, we assess a robustness check with different functional forms using our main specification and sample period (Supp. Tab. 14). While for the vast majority of countries the BIC is minimized with our main specification compared to the less complex ones omitting the squared or linear term, few countries exhibit similar BICs with the quadratic specification (Romania, Hungary, Croatia). A few countries also have a minimum BIC under the levels specification, where the dependent variable coal generation is not log-transformed. However, to account for the large variation in coal capacity of different countries we use a log-transform for interpretation purposes. An additional robustness check is concluded by running the pooled regression to get an average estimates for all countries, including country fixed effects and thus controlling for any EU-wide shocks. This elasticity estimate (0.21) is significant and similar to the average of the country specific estimates (0.26).

Bulgaria						
VARIABLES	(1)	(2)	(3)	(4)	(5)	(6)
Relative Price	3.71*** (0.081)	3.38*** (0.070)	3.49*** (0.063)	1.96*** (0.055)	1.96*** (0.244)	1.96*** (0.055)
Relative Price Squared	-1.22*** (0.031)	-1.16*** (0.027)	-1.19*** (0.025)	-0.69*** (0.021)	-0.69*** (0.094)	-0.69*** (0.021)
Relative Price Cubed	0.13*** (0.004)	0.12*** (0.003)	0.13*** (0.003)	0.08*** (0.003)	0.08*** (0.012)	0.08*** (0.003)
Intermittent Renewables (GWh)		-0.13*** (0.007)	-0.18*** (0.006)	-0.15*** (0.006)	-0.15*** (0.019)	-0.15*** (0.006)
Nuclear (GWh)			-0.00*** (0.000)			
Load (GWh)		0.37*** (0.022)	0.45*** (0.017)	0.31*** (0.015)	0.31*** (0.045)	0.31*** (0.015)
Load Squared (GWh)			-0.03*** (0.002)	-0.02*** (0.001)	-0.02*** (0.004)	-0.02*** (0.001)
Observations	10,223	10,223	10,223	10,223	10,223	10,223
Adjusted R-squared	0.549	0.650	0.749	0.895	0.895	
Month FE	NO	NO	NO	YES	YES	YES
Hour FE	NO	NO	NO	YES	YES	YES
Day-of-Week FE	NO	NO	NO	YES	YES	YES
SE	Robust	Robust	Robust	Robust	Day Clustered	Newey
Marginal Effect	0.618	0.481	0.504	0.259	0.259	0.259
Robust standard errors in parentheses						
*** p<0.01, ** p<0.05, * p<0.1						

Supplementary Tab. 1: Coal responsiveness regression estimates for Bulgaria under alternative model specifications, with column (5) being our main preferred specification. The dependent variable is log-transformed coal generation. The marginal effect, shown on the bottom, is our main estimate of interest, derived through the delta method from the Relative Price Coefficients. The statistical test used is a two-sided t-test. * indicates significance at the 10% level, ** indicates significance at the 5% level, and *** indicates significance at the 1% level.

Croatia						
VARIABLES	(1)	(2)	(3)	(4)	(5)	(6)
Relative Price	0.58*** (0.071)	0.49*** (0.072)	0.49*** (0.072)	0.45*** (0.134)	0.45 (0.401)	0.45*** (0.139)
Relative Price Squared	-0.23*** (0.027)	-0.19*** (0.028)	-0.19*** (0.028)	-0.13*** (0.047)	-0.13 (0.141)	-0.13*** (0.049)
Relative Price Cubed	0.02*** (0.003)	0.02*** (0.003)	0.02*** (0.003)	0.01* (0.005)	0.01 (0.015)	0.01* (0.005)
Intermittent Renewables (GWh)		-0.07*** (0.011)	-0.07*** (0.011)	-0.07*** (0.010)	-0.07*** (0.023)	-0.07*** (0.010)
Load (GWh)		0.08** (0.039)	0.08** (0.039)	0.25*** (0.055)	0.25** (0.118)	0.25*** (0.055)
Load Squared (GWh)			-0.01 (0.009)	-0.04*** (0.012)	-0.04 (0.023)	-0.04*** (0.012)
Observations	7,981	7,981	7,981	7,981	7,981	7,981
Adjusted R-squared	0.085	0.096	0.096	0.205	0.205	
Month FE	NO	NO	NO	YES	YES	YES
Hour FE	NO	NO	NO	YES	YES	YES
Day-of-Week FE	NO	NO	NO	YES	YES	YES
SE	Robust	Robust	Robust	Robust	Day Clustered	Newey
Marginal Effect	-0.0277	-0.0267	-0.0267	0.0836	0.0836	0.0836
Robust standard errors in parentheses						
*** p<0.01, ** p<0.05, * p<0.1						

Supplementary Tab. 2: Coal responsiveness regression estimates for Croatia under alternative model specifications, with column (5) being our main preferred specification. The dependent variable is log-transformed coal generation. The marginal effect, shown on the bottom, is our main estimate of interest, derived through the delta method from the Relative Price Coefficients. The statistical test used is a two-sided t-test. * indicates significance at the 10% level, ** indicates significance at the 5% level, and *** indicates significance at the 1% level.

Czechia						
VARIABLES	(1)	(2)	(3)	(4)	(5)	(6)
Relative Price	1.53*** (0.063)	1.82*** (0.053)	1.94*** (0.055)	1.28*** (0.062)	1.28*** (0.280)	1.28*** (0.063)
Relative Price Squared	-0.37*** (0.024)	-0.56*** (0.021)	-0.59*** (0.021)	-0.43*** (0.025)	-0.43*** (0.111)	-0.43*** (0.025)
Relative Price Cubed	0.03*** (0.003)	0.06*** (0.003)	0.06*** (0.003)	0.05*** (0.003)	0.05*** (0.013)	0.05*** (0.003)
Intermittent Renewables (GWh)		-0.15*** (0.005)	-0.15*** (0.005)	-0.05*** (0.007)	-0.05*** (0.017)	-0.05*** (0.007)
Nuclear (GWh)			-0.00*** (0.000)			
Load (GWh)		0.14*** (0.014)	0.15*** (0.014)	0.12*** (0.015)	0.12*** (0.044)	0.12*** (0.015)
Load Squared (GWh)^2			-0.00*** (0.001)	-0.00 (0.001)	-0.00 (0.002)	-0.00 (0.001)
Observations	10,224	10,224	10,224	10,224	10,224	10,224
Adjusted R-squared	0.548	0.702	0.703	0.781	0.781	
Month FE	NO	NO	NO	YES	YES	YES
Hour FE	NO	NO	NO	YES	YES	YES
Day-of-Week FE	NO	NO	NO	YES	YES	YES
SE	Robust	Robust	Robust	Robust	Day Clustered	Newey
Marginal Effect	0.489	0.386	0.410	0.224	0.224	0.224
Robust standard errors in parentheses						
*** p<0.01, ** p<0.05, * p<0.1						

Supplementary Tab. 3: Coal responsiveness regression estimates for Czechia under alternative model specifications, with column (5) being our main preferred specification. The dependent variable is log-transformed coal generation. The marginal effect, shown on the bottom, is our main estimate of interest, derived through the delta method from the Relative Price Coefficients. The statistical test used is a two-sided t-test. * indicates significance at the 10% level, ** indicates significance at the 5% level, and *** indicates significance at the 1% level.

Denmark					
VARIABLES	(1)	(2)	(3)	(4)	(5)
Relative Price	-0.22 (0.135)	0.87*** (0.131)	0.87*** (0.131)	1.28*** (0.137)	1.28** (0.541)
Relative Price Squared	0.26*** (0.054)	-0.18*** (0.053)	-0.18*** (0.053)	-0.38*** (0.054)	-0.38* (0.214)
Relative Price Cubed	-0.03*** (0.006)	0.02** (0.007)	0.02** (0.007)	0.04*** (0.007)	0.04 (0.026)
Intermittent Renewables (GWh)		-0.15*** (0.003)	-0.15*** (0.003)	-0.16*** (0.003)	-0.16*** (0.010)
Load (GWh)		0.17*** (0.064)	0.17*** (0.064)	0.09 (0.070)	0.09 (0.161)
Load Squared (GWh)			0.01 (0.008)	0.01* (0.008)	0.01 (0.016)
Observations	10,223	10,223	10,223	10,223	10,223
Adjusted R-squared	0.193	0.373	0.373	0.553	0.553
Month FE	NO	NO	YES	YES	YES
Hour FE	NO	NO	NO	YES	YES
Day-of-Week FE	NO	NO	NO	YES	YES
SE	Robust	Robust	Robust	Robust	Day Clustered
Marginal Effect	0.375	0.383	0.383	0.302	0.302
Robust standard errors in parentheses					
*** p<0.01, ** p<0.05, * p<0.1					

Supplementary Tab. 4: Coal responsiveness regression estimates for Denmark under alternative model specifications, with column (5) being our main preferred specification. The dependent variable is log-transformed coal generation. The marginal effect, shown on the bottom, is our main estimate of interest, derived through the delta method from the Relative Price Coefficients. The statistical test used is a two-sided t-test. * indicates significance at the 10% level, ** indicates significance at the 5% level, and *** indicates significance at the 1% level.

Germany						
VARIABLES	(1)	(2)	(3)	(4)	(5)	(6)
Relative Price	1.68*** (0.102)	2.40*** (0.068)	2.09*** (0.072)	2.43*** (0.075)	2.43*** (0.307)	2.43*** (0.076)
Relative Price Squared	-0.47*** (0.039)	-0.80*** (0.027)	-0.68*** (0.029)	-0.79*** (0.030)	-0.79*** (0.122)	-0.79*** (0.031)
Relative Price Cubed	0.04*** (0.005)	0.08*** (0.003)	0.07*** (0.004)	0.08*** (0.004)	0.08*** (0.015)	0.08*** (0.004)
Intermittent Renewables (GWh)		-0.02*** (0.000)	-0.02*** (0.000)	-0.02*** (0.000)	-0.02*** (0.001)	-0.02*** (0.000)
Nuclear (GWh)			-0.00*** (0.000)			
Load (GWh)		0.05*** (0.003)	0.05*** (0.003)	0.08*** (0.003)	0.08*** (0.008)	0.08*** (0.003)
Load Squared (GWh)			-0.00*** (0.000)	-0.00*** (0.000)	-0.00*** (0.000)	-0.00*** (0.000)
Observations	10,224	10,224	10,224	10,224	10,224	10,224
Adjusted R-squared	0.256	0.750	0.753	0.808	0.808	
Month FE	NO	NO	NO	YES	YES	YES
Hour FE	NO	NO	NO	YES	YES	YES
Day-of-Week FE	NO	NO	NO	YES	YES	YES
SE	Robust	Robust	Robust	Robust	Day Clustered	Newey
Marginal Effect	0.443	0.364	0.343	0.411	0.411	0.411
Robust standard errors in parentheses						
*** p<0.01, ** p<0.05, * p<0.1						

Supplementary Tab. 5: Coal responsiveness regression estimates for Germany under alternative model specifications, with column (5) being our main preferred specification. The dependent variable is log-transformed coal generation. The marginal effect, shown on the bottom, is our main estimate of interest, derived through the delta method from the Relative Price Coefficients. The statistical test used is a two-sided t-test. * indicates significance at the 10% level, ** indicates significance at the 5% level, and *** indicates significance at the 1% level.

Finland						
VARIABLES	(1)	(2)	(3)	(4)	(5)	(6)
Relative Price	4.18*** (0.216)	4.56*** (0.171)	4.31*** (0.175)	3.27*** (0.108)	3.27*** (0.460)	3.27*** (0.109)
Relative Price Squared	-1.18*** (0.083)	-1.66*** (0.066)	-1.58*** (0.067)	-1.10*** (0.040)	-1.10*** (0.168)	-1.10*** (0.041)
Relative Price Cubed	0.11*** (0.010)	0.19*** (0.008)	0.18*** (0.008)	0.12*** (0.005)	0.12*** (0.019)	0.12*** (0.005)
Intermittent Renewables (GWh)		-0.08*** (0.008)	-0.06*** (0.008)	-0.06*** (0.005)	-0.06*** (0.018)	-0.06*** (0.005)
Nuclear (GWh)			0.00*** (0.000)			
Load (GWh)		1.48*** (0.056)	1.40*** (0.057)	0.70*** (0.041)	0.70*** (0.122)	0.70*** (0.042)
Load Squared (GWh)			-0.05*** (0.003)	-0.02*** (0.002)	-0.02*** (0.005)	-0.02*** (0.002)
Observations	8,882	8,882	8,882	8,882	8,882	8,882
Adjusted R-squared	0.319	0.543	0.545	0.824	0.824	
Month FE	NO	NO	NO	YES	YES	YES
Hour FE	NO	NO	NO	YES	YES	YES
Day-of-Week FE	NO	NO	NO	YES	YES	YES
SE	Robust	Robust	Robust	Robust	Day Clustered	Newey
Marginal Effect	1.015	0.467	0.433	0.463	0.463	0.463
Robust standard errors in parentheses						
*** p<0.01, ** p<0.05, * p<0.1						

Supplementary Tab. 6: Coal responsiveness regression estimates for Finland under alternative model specifications, with column (5) being our main preferred specification. The dependent variable is log-transformed coal generation. The marginal effect, shown on the bottom, is our main estimate of interest, derived through the delta method from the Relative Price Coefficients. The statistical test used is a two-sided t-test. * indicates significance at the 10% level, ** indicates significance at the 5% level, and *** indicates significance at the 1% level.

Greece					
VARIABLES	(1)	(2)	(3)	(4)	(5)
Relative Price	-0.74*** (0.160)	-1.38*** (0.155)	-1.38*** (0.155)	-0.24 (0.188)	-0.24 (0.855)
Relative Price Squared	0.29*** (0.065)	0.60*** (0.063)	0.60*** (0.063)	0.19** (0.074)	0.19 (0.336)
Relative Price Cubed	-0.03*** (0.008)	-0.07*** (0.008)	-0.07*** (0.008)	-0.02*** (0.009)	-0.02 (0.040)
Intermittent Renewables (GWh)		-0.11*** (0.005)	-0.11*** (0.005)	-0.06*** (0.006)	-0.06*** (0.024)
Load (GWh)		0.05** (0.024)	0.05** (0.024)	0.46*** (0.035)	0.46*** (0.087)
Load Squared (GWh)			0.02*** (0.002)	-0.01*** (0.003)	-0.01* (0.006)
Observations	10,213	10,213	10,213	10,213	10,213
Adjusted R-squared	0.040	0.303	0.303	0.388	0.388
Month FE	NO	NO	NO	NO	NO
Hour FE	NO	NO	NO	YES	YES
Day-of-Week FE	NO	NO	NO	YES	YES
SE	Robust	Robust	Robust	Robust	Day Clustered
Marginal Effect	0.0813	0.0659	0.0659	0.179	0.179
Robust standard errors in parentheses					
*** p<0.01, ** p<0.05, * p<0.1					

Supplementary Tab. 7: Coal responsiveness regression estimates for Greece under alternative model specifications, with column (5) being our main preferred specification. The dependent variable is log-transformed coal generation. The marginal effect, shown on the bottom, is our main estimate of interest, derived through the delta method from the Relative Price Coefficients. The statistical test used is a two-sided t-test. * indicates significance at the 10% level, ** indicates significance at the 5% level, and *** indicates significance at the 1% level.

Hungary						
VARIABLES	(1)	(2)	(3)	(4)	(5)	(6)
Relative Price	0.31*** (0.075)	0.34*** (0.074)	0.43*** (0.076)	0.09 (0.069)	0.09 (0.270)	0.09 (0.069)
Relative Price Squared	-0.10*** (0.029)	-0.13*** (0.029)	-0.17*** (0.029)	-0.00 (0.026)	-0.00 (0.102)	-0.00 (0.026)
Relative Price Cubed	0.01*** (0.003)	0.02*** (0.003)	0.02*** (0.004)	-0.00 (0.003)	-0.00 (0.012)	-0.00 (0.003)
Intermittent Renewables (GWh)		-0.01 (0.006)	-0.01 (0.006)	0.06*** (0.011)	0.06** (0.026)	0.06*** (0.011)
Nuclear (GWh)			-0.00*** (0.000)			
Load (GWh)		0.22*** (0.030)	0.23*** (0.029)	0.17*** (0.029)	0.17** (0.077)	0.17*** (0.029)
Load Squared (GWh)			-0.02*** (0.003)	-0.01** (0.003)	-0.01 (0.007)	-0.01** (0.003)
Observations	10,210	10,210	10,210	10,210	10,210	10,210
Adjusted R-squared	0.008	0.041	0.048	0.139	0.139	
Month FE	NO	NO	NO	YES	YES	YES
Hour FE	NO	NO	NO	YES	YES	YES
Day-of-Week FE	NO	NO	NO	YES	YES	YES
SE	Robust	Robust	Robust	Robust	Day Clustered	Newey
Marginal Effect	0.0524	0.0263	0.0267	0.0454	0.0454	0.0454
Robust standard errors in parentheses						
*** p<0.01, ** p<0.05, * p<0.1						

Supplementary Tab. 8: Coal responsiveness regression estimates for Hungary under alternative model specifications, with column (5) being our main preferred specification. The dependent variable is log-transformed coal generation. The marginal effect, shown on the bottom, is our main estimate of interest, derived through the delta method from the Relative Price Coefficients. The statistical test used is a two-sided t-test. * indicates significance at the 10% level, ** indicates significance at the 5% level, and *** indicates significance at the 1% level.

Ireland						
VARIABLES	(1)	(2)	(3)	(4)	(5)	(6)
Relative Price	-2.02*** (0.171)	0.63*** (0.132)	0.63*** (0.132)	-2.11*** (0.219)	-2.11*** (0.759)	-2.11*** (0.221)
Relative Price Squared	1.03*** (0.070)	-0.03 (0.054)	-0.03 (0.054)	0.91*** (0.081)	0.91*** (0.276)	0.91*** (0.081)
Relative Price Cubed	-0.14*** (0.009)	-0.01 (0.007)	-0.01 (0.007)	-0.11*** (0.009)	-0.11*** (0.032)	-0.11*** (0.009)
Intermittent Renewables (GWh)		-0.32*** (0.004)	-0.32*** (0.004)	-0.33*** (0.005)	-0.33*** (0.016)	-0.33*** (0.005)
Load (GWh)		0.08*** (0.011)	0.08*** (0.011)	0.08*** (0.017)	0.08* (0.050)	0.08*** (0.017)
Load Squared (GWh)			0.04*** (0.002)	0.01*** (0.004)	0.01 (0.010)	0.01*** (0.004)
Observations	9,974	9,974	9,974	9,974	9,974	9,974
Adjusted R-squared	0.125	0.583	0.583	0.629	0.629	
Month FE	NO	NO	NO	YES	YES	YES
Hour FE	NO	NO	NO	YES	YES	YES
Day-of-Week FE	NO	NO	NO	YES	YES	YES
SE	Robust	Robust	Robust	Robust	Day Clustered	Newey
Marginal Effect	0.249	0.408	0.408	0.0295	0.0295	0.0295
Robust standard errors in parentheses						
*** p<0.01, ** p<0.05, * p<0.1						

Supplementary Tab. 9: Coal responsiveness regression estimates for Ireland under alternative model specifications, with column (5) being our main preferred specification. The dependent variable is log-transformed coal generation. The marginal effect, shown on the bottom, is our main estimate of interest, derived through the delta method from the Relative Price Coefficients. The statistical test used is a two-sided t-test. * indicates significance at the 10% level, ** indicates significance at the 5% level, and *** indicates significance at the 1% level.

Italy						
VARIABLES	(1)	(2)	(3)	(4)	(5)	(6)
Relative Price	4.30*** (0.125)	3.42*** (0.123)	3.42*** (0.123)	4.32*** (0.135)	4.32*** (0.603)	4.32*** (0.135)
Relative Price Squared	-1.51*** (0.053)	-1.19*** (0.051)	-1.19*** (0.051)	-1.42*** (0.053)	-1.42*** (0.239)	-1.42*** (0.053)
Relative Price Cubed	0.17*** (0.007)	0.14*** (0.007)	0.14*** (0.007)	0.15*** (0.007)	0.15*** (0.030)	0.15*** (0.007)
Intermittent Renewables (GWh)		-0.03*** (0.001)	-0.03*** (0.001)	-0.04*** (0.002)	-0.04*** (0.005)	-0.04*** (0.002)
Load (GWh)		0.02*** (0.004)	0.02*** (0.004)	0.04*** (0.005)	0.04** (0.019)	0.04*** (0.006)
Load Squared (GWh)			0.00 (0.000)	-0.00*** (0.000)	-0.00 (0.000)	-0.00*** (0.000)
Observations	10,224	10,224	10,224	10,224	10,224	10,224
Adjusted R-squared	0.314	0.407	0.407	0.529	0.529	
Month FE	NO	NO	NO	YES	YES	YES
Hour FE	NO	NO	NO	YES	YES	YES
Day-of-Week FE	NO	NO	NO	YES	YES	YES
SE	Robust	Robust	Robust	Robust	Day Clustered	Newey
Marginal Effect	0.630	0.499	0.499	0.747	0.747	0.747
Robust standard errors in parentheses						
*** p<0.01, ** p<0.05, * p<0.1						

Supplementary Tab. 10: Coal responsiveness regression estimates for Italy under alternative model specifications, with column (5) being our main preferred specification. The dependent variable is log-transformed coal generation. The marginal effect, shown on the bottom, is our main estimate of interest, derived through the delta method from the Relative Price Coefficients. The statistical test used is a two-sided t-test. * indicates significance at the 10% level, ** indicates significance at the 5% level, and *** indicates significance at the 1% level.

Netherlands						
VARIABLES	(1)	(2)	(3)	(4)	(5)	(6)
Relative Price	0.96*** (0.139)	1.37*** (0.126)	0.77*** (0.116)	-1.88*** (0.145)	-1.88*** (0.642)	-1.88*** (0.147)
Relative Price Squared	0.03 (0.056)	-0.18*** (0.050)	0.03 (0.047)	0.88*** (0.056)	0.88*** (0.244)	0.88*** (0.056)
Relative Price Cubed	-0.03*** (0.007)	-0.00 (0.006)	-0.03*** (0.006)	-0.12*** (0.007)	-0.12*** (0.029)	-0.12*** (0.007)
Intermittent Renewables (GWh)		-0.09*** (0.004)	-0.09*** (0.004)	-0.11*** (0.003)	-0.11*** (0.012)	-0.11*** (0.003)
Nuclear (GWh)			0.00*** (0.000)			
Load (GWh)		0.26*** (0.011)	0.25*** (0.012)	0.27*** (0.010)	0.27*** (0.023)	0.27*** (0.010)
Load Squared (GWh)			-0.01*** (0.001)	-0.01*** (0.000)	-0.01*** (0.001)	-0.01*** (0.000)
Observations	10,206	10,206	10,206	10,206	10,206	10,206
Adjusted R-squared	0.318	0.463	0.496	0.731	0.731	
Month FE	NO	NO	NO	YES	YES	YES
Hour FE	NO	NO	NO	YES	YES	YES
Day-of-Week FE	NO	NO	NO	YES	YES	YES
SE	Robust	Robust	Robust	Robust	Day Clustered	Newey
Marginal Effect	0.728	0.654	0.558	0.0868	0.0868	0.0868
Robust standard errors in parentheses						
*** p<0.01, ** p<0.05, * p<0.1						

Supplementary Tab. 11: Coal responsiveness regression estimates for Netherlands under alternative model specifications, with column (5) being our main preferred specification. The dependent variable is log-transformed coal generation. The marginal effect, shown on the bottom, is our main estimate of interest, derived through the delta method from the Relative Price Coefficients. The statistical test used is a two-sided t-test. * indicates significance at the 10% level, ** indicates significance at the 5% level, and *** indicates significance at the 1% level.

Romania						
VARIABLES	(1)	(2)	(3)	(4)	(5)	(6)
Relative Price	-0.15*** (0.049)	-0.34*** (0.042)	-0.35*** (0.044)	0.13*** (0.049)	0.13 (0.194)	0.13*** (0.049)
Relative Price Squared	0.07*** (0.019)	0.12*** (0.017)	0.12*** (0.017)	-0.04** (0.019)	-0.04 (0.075)	-0.04** (0.019)
Relative Price Cubed	-0.01*** (0.002)	-0.01*** (0.002)	-0.01*** (0.002)	0.00** (0.002)	0.00 (0.009)	0.00* (0.002)
Intermittent Renewables (GWh)		-0.07*** (0.002)	-0.07*** (0.002)	-0.06*** (0.002)	-0.06*** (0.006)	-0.06*** (0.002)
Nuclear (GWh)			0.00 (0.000)			
Load (GWh)		0.35*** (0.016)	0.35*** (0.016)	0.43*** (0.016)	0.43*** (0.044)	0.43*** (0.016)
Load Squared (GWh)			-0.02*** (0.001)	-0.02*** (0.001)	-0.02*** (0.003)	-0.02*** (0.001)
Observations	10,173	10,173	10,173	10,173	10,173	10,173
Adjusted R-squared	0.004	0.285	0.285	0.490	0.490	
Month FE	NO	NO	NO	YES	YES	YES
Hour FE	NO	NO	NO	YES	YES	YES
Day-of-Week FE	NO	NO	NO	YES	YES	YES
SE	Robust	Robust	Robust	Robust	Day Clustered	Newey
Marginal Effect	0.00643	-0.0488	-0.0499	0.0206	0.0206	0.0206
Robust standard errors in parentheses						
*** p<0.01, ** p<0.05, * p<0.1						

Supplementary Tab. 12: Coal responsiveness regression estimates for Romania under alternative model specifications, with column (5) being our main preferred specification. The dependent variable is log-transformed coal generation. The marginal effect, shown on the bottom, is our main estimate of interest, derived through the delta method from the Relative Price Coefficients. The statistical test used is a two-sided t-test. * indicates significance at the 10% level, ** indicates significance at the 5% level, and *** indicates significance at the 1% level.

Poland						
VARIABLES	(1)	(2)	(3)	(4)	(5)	(6)
Relative Price	0.19*** (0.061)	0.62*** (0.024)	0.62*** (0.024)	0.59*** (0.023)	0.59*** (0.078)	0.59*** (0.023)
Relative Price Squared	-0.01 (0.024)	-0.21*** (0.010)	-0.21*** (0.010)	-0.19*** (0.009)	-0.19*** (0.030)	-0.19*** (0.009)
Relative Price Cubed	-0.00 (0.003)	0.02*** (0.001)	0.02*** (0.001)	0.02*** (0.001)	0.02*** (0.003)	0.02*** (0.001)
Intermittent Renewables (GWh)		-0.06*** (0.000)	-0.06*** (0.000)	-0.05*** (0.000)	-0.05*** (0.001)	-0.05*** (0.000)
Load (GWh)		0.13*** (0.003)	0.13*** (0.003)	0.14*** (0.003)	0.14*** (0.009)	0.14*** (0.003)
Load Squared (GWh)			-0.00*** (0.000)	-0.00*** (0.000)	-0.00*** (0.000)	-0.00*** (0.000)
Observations	10,224	10,224	10,224	10,224	10,224	10,224
Adjusted R-squared	0.123	0.877	0.877	0.911	0.911	
Month FE	NO	NO	NO	YES	YES	YES
Hour FE	NO	NO	NO	YES	YES	YES
Day-of-Week FE	NO	NO	NO	YES	YES	YES
SE	Robust	Robust	Robust	Robust	Day Clustered	Newey
Marginal Effect	0.135	0.0908	0.0908	0.103	0.103	0.103
Robust standard errors in parentheses						
*** p<0.01, ** p<0.05, * p<0.1						

Supplementary Tab. 13: Coal responsiveness regression estimates for Poland under alternative model specifications, with column (5) being our main preferred specification. The dependent variable is log-transformed coal generation. The marginal effect, shown on the bottom, is our main estimate of interest, derived through the delta method from the Relative Price Coefficients. The statistical test used is a two-sided t-test. * indicates significance at the 10% level, ** indicates significance at the 5% level, and *** indicates significance at the 1% level.

Country	Main (BIC)	Quadratic (BIC)	Linear (BIC)	Levels (BIC)
Bulgaria	0.259 (-15781)	0.215 (-14788)	0.125 (-13896)	0.565 (371)
Czech Republic	0.224 (-10530)	0.199 (-10307)	0.141 (-10081)	0.627 (12335)
Germany	0.411 (-6633)	0.366 (-6169)	0.204 (-4991)	5.481 (44168)
Denmark	0.302 (7979)	0.281 (7994)	0.195 (8072)	0.198 (-2926)
Spain	0.705 (4722)	0.612 (5298)	0.322 (6485)	0.503 (-2141)
Finland	0.463 (7641)	0.419 (7850)	0.256 (8181)	0.151 (-19702)
Greece	0.209 (12839)	0.209 (12839)	0.200 (12831)	0.072 (-701)
Croatia	0.084 (-8001)	0.069 (-8004)	0.006 (-7936)	0.110 (-30657)
Hungary	0.045 (-2380)	0.047 (-2389)	0.013 (-2360)	0.006 (-26844)
Italy	0.747 (5517)	0.656 (6002)	0.413 (6818)	1.205 (14661)
Ireland	0.029 (7713)	0.162 (7863)	0.178 (7855)	0.040 (-12084)
Netherlands	0.087 (7061)	0.153 (7310)	0.107 (7327)	0.338 (16598)
Poland	0.103 (-27843)	0.092 (-27644)	0.049 (-26997)	1.322 (22270)
Romania	0.021 (-15124)	0.018 (-15130)	0.008 (-15129)	0.002 (-11768)
Average	0.264	0.206	0.155	0.436

Supplementary Tab. 14: Coal responsiveness regression estimates under different functional forms. The marginal estimate (derived through the delta method) is shown for each country, with the BIC in parenthesis. A more negative BIC indicates better fit. The main functional form includes a cubic, quadratic, and linear term of the relative price. The quadratic column includes a quadratic and a linear term, and the linear column includes only a linear term. The levels column is the same as the main regression but, in contrast to the others, the dependent variable of coal generation is in levels rather than logs. The sample size for each country is shown in Extended Data Fig. 5.

Country	January 2021- January 2022	April 2021- November 2021	April 2021- January 2022	April 2021- March 2022	(Main Spec.) April 2021- June 2022
Bulgaria	0.307***	0.602***	0.277***	0.203***	0.259***
Czech Republic	-0.0414	-0.0421	-0.0224	0.0197	0.224***
Germany	0.295***	0.608***	0.292***	0.259***	0.411***
Denmark	-0.0137	0.145	0.0337	0.00214	0.302***
Spain	-0.174	-0.279	-0.184	-0.163	0.705***
Finland	0.289	-0.426	0.251	0.265**	0.463***
Greece	1.449***	2.034***	0.451***	-0.172*	0.179***
Croatia	0.0231	0.0923	0.0141	0.0258	0.0836*
Hungary	0.420***	1.086***	0.380*	0.323***	0.0454
Italy	1.369***	1.742***	1.164***	0.825***	0.747***
Ireland	-0.113	0.0374	-0.0685	0.150	0.0295
Netherlands	0.109	0.0657	0.104	0.0882	0.0868
Poland	0.0904***	0.156***	0.0894***	0.0834***	0.103***
Romania	-0.192	-0.0937	-0.191	-0.0723*	0.0206
Average	0.301	0.351	0.161	0.142	0.265

Supplementary Tab. 15: Main (marginal) coal responsiveness estimate shown for each country under different time periods, using the main regression specification. The statistical test used is a two-sided t-test. * indicates significance at the 10% level, ** indicates significance at the 5% level, and *** indicates significance at the 1% level. More detailed regression results for each time period are shown in Supp. Tab. 16-19.

April 2021 - January 2022														
VARIABLES	(1) BG	(2) CZ	(3) DE	(4) DK	(5) ES	(6) FI	(7) GR	(8) HR	(9) HU	(10) IT	(11) IE	(12) NL	(13) PL	(14) RO
Relative Price	1.520*** (0.383)	-0.696* (0.411)	1.262** (0.529)	-0.891 (1.063)	-1.557** (0.764)	1.406 (1.139)	1.354 (1.005)	-0.008 (0.384)	2.195*** (0.760)	5.689*** (1.406)	-1.108 (0.882)	0.064 (0.939)	0.499*** (0.153)	-0.574* (0.311)
Relative Price Squared	-0.495*** (0.136)	0.273* (0.148)	-0.363* (0.193)	0.394 (0.360)	0.588** (0.252)	-0.449 (0.375)	-0.348 (0.355)	0.024 (0.142)	-0.708*** (0.259)	-1.791*** (0.487)	0.427 (0.309)	0.060 (0.322)	-0.160*** (0.051)	0.133 (0.112)
Relative Price Cubed	0.052*** (0.015)	-0.030* (0.016)	0.033 (0.022)	-0.047 (0.039)	-0.071*** (0.027)	0.047 (0.040)	0.034 (0.040)	-0.006 (0.016)	0.071** (0.028)	0.186*** (0.054)	-0.048 (0.034)	-0.016 (0.035)	0.016*** (0.005)	-0.010 (0.013)
Intermittent Renewables (GWh)	-0.135*** (0.023)	-0.067*** (0.021)	-0.024*** (0.001)	-0.143*** (0.013)	-0.024*** (0.003)	-0.112*** (0.021)	-0.073*** (0.028)	-0.056** (0.027)	0.091** (0.035)	-0.025*** (0.006)	-0.325*** (0.017)	-0.103*** (0.013)	-0.053*** (0.002)	-0.043*** (0.006)
Load (GWh)	0.279*** (0.057)	0.246*** (0.049)	0.104*** (0.009)	0.268 (0.183)	0.109*** (0.031)	1.152*** (0.135)	0.189** (0.090)	0.362** (0.143)	0.141 (0.097)	-0.019 (0.014)	-0.278*** (0.039)	0.269*** (0.040)	0.157*** (0.010)	0.339*** (0.054)
Load Squared (GWh)	-0.016*** (0.005)	-0.008*** (0.003)	-0.001*** (0.000)	0.001 (0.018)	-0.002*** (0.000)	-0.040*** (0.006)	0.007 (0.006)	-0.056** (0.028)	-0.003 (0.009)	0.001*** (0.000)	0.071*** (0.010)	-0.010*** (0.002)	-0.002*** (0.000)	-0.018*** (0.003)
Observations	7,344	7,344	7,344	7,344	7,326	6,002	7,344	5,847	7,330	7,344	7,240	7,326	7,344	7,293
R-squared	0.912	0.818	0.822	0.565	0.683	0.848	0.320	0.322	0.155	0.535	0.579	0.751	0.914	0.542
Month FE	YES	YES	YES	YES	YES	YES	YES	YES						
Hour FE	YES	YES	YES	YES	YES	YES	YES	YES						
Day of Week FE	YES	YES	YES	YES	YES	YES	YES	YES						
Marginal Effect	0.277	-0.0224	0.292	0.0337	-0.184	0.251	0.451	0.0141	0.380	1.164	-0.0685	0.104	0.0894	-0.191

Robust standard errors in parentheses
*** p<0.01, ** p<0.05, * p<0.1

Supplementary Tab. 16: Estimates of main regression results of responsiveness of log-transformed coal generation factor to relative price (natural gas price/coal price), during April 1 2021-December 31 2021. The marginal effect, which is the estimate of interest, is derived through the delta method from the relative price coefficients, using the mean value of relative price during this period. Standard errors are clustered at the daily level, which is the unit of variation of the treatment variable. The statistical test used is the two-sided t-test. * indicates significance at the 10% level, ** indicates significance at the 5% level, and *** indicates significance at the 1% level.

January 2021 - December 2021														
VARIABLES	(1) BG	(2) CZ	(3) DE	(4) DK	(5) ES	(6) FI	(7) GR	(8) HR	(9) HU	(10) IT	(11) IE	(12) NL	(13) PL	(14) RO
Relative Price	1.389*** (0.385)	-0.773* (0.406)	1.259** (0.525)	-0.837 (1.074)	-1.225 (0.754)	1.438 (1.162)	4.498*** (1.057)	-0.029 (0.381)	2.209*** (0.764)	5.795*** (1.372)	-1.205 (0.887)	-0.008 (0.955)	0.477*** (0.153)	-0.617** (0.310)
Relative Price Squared	-0.434*** (0.135)	0.302** (0.148)	-0.369* (0.195)	0.346 (0.364)	0.464* (0.244)	-0.451 (0.379)	-1.155*** (0.360)	0.036 (0.141)	-0.708*** (0.259)	-1.758*** (0.468)	0.452 (0.311)	0.094 (0.327)	-0.153*** (0.051)	0.156 (0.111)
Relative Price Cubed	0.045*** (0.015)	-0.033* (0.017)	0.034 (0.022)	-0.039 (0.039)	-0.057** (0.026)	0.047 (0.040)	0.105** (0.040)	-0.007 (0.016)	0.071** (0.028)	0.178*** (0.052)	-0.050 (0.034)	-0.020 (0.035)	0.015*** (0.005)	-0.013 (0.012)
Intermittent Renewables (GWh)	-0.138*** (0.026)	-0.071*** (0.022)	-0.025*** (0.001)	-0.126*** (0.013)	-0.027*** (0.003)	-0.112*** (0.027)	-0.063** (0.028)	-0.037 (0.025)	0.087** (0.040)	-0.022*** (0.006)	-0.332*** (0.019)	-0.101*** (0.015)	-0.055*** (0.002)	-0.043*** (0.007)
Load (GWh)	0.299*** (0.070)	0.250*** (0.051)	0.101*** (0.009)	0.379* (0.193)	0.094*** (0.035)	1.120*** (0.138)	0.244** (0.095)	0.343** (0.159)	0.044 (0.122)	-0.039*** (0.015)	-0.281*** (0.044)	0.270*** (0.042)	0.164*** (0.011)	0.302*** (0.063)
Load Squared (GWh)	-0.022*** (0.006)	-0.010*** (0.003)	-0.001*** (0.000)	-0.014 (0.019)	-0.001** (0.001)	-0.038*** (0.006)	0.004 (0.006)	-0.067** (0.031)	0.006 (0.012)	0.001*** (0.000)	0.073*** (0.011)	-0.010*** (0.002)	-0.003*** (0.000)	-0.015*** (0.004)
Observations	6,600	6,600	6,600	6,600	6,583	5,258	6,600	5,103	6,586	6,600	6,496	6,582	6,600	6,549
R-squared	0.907	0.810	0.826	0.557	0.660	0.836	0.409	0.348	0.145	0.544	0.559	0.748	0.912	0.537
Month FE	YES	YES	YES	YES	YES	YES	YES	YES						
Hour FE	YES	YES	YES	YES	YES	YES	YES	YES						
Day of Week FE	YES	YES	YES	YES	YES	YES	YES	YES						
Marginal Effect	0.307	-0.0414	0.295	-0.0137	-0.174	0.289	1.449	0.0231	0.420	1.369	-0.113	0.109	0.0904	-0.192
Robust standard errors in parentheses														
*** p<0.01, ** p<0.05, * p<0.1														

Supplementary Tab. 17: Estimates of main regression results of responsiveness of log-transformed coal generation factor to relative price (natural gas price/coal price), during January 1 2021-December 31 2021. The marginal effect, which is the estimate of interest, is derived through the delta method from the relative price coefficients, using the mean value of relative price during this period. Standard errors are clustered at the daily level, which is the unit of variation of the treatment variable. The statistical test used is the two-sided t-test. * indicates significance at the 10% level, ** indicates significance at the 5% level, and *** indicates significance at the 1% level.

April 2021 - March 2022														
VARIABLES	(1) BG	(2) CZ	(3) DE	(4) DK	(5) ES	(6) FI	(7) GR	(8) HR	(9) HU	(10) IT	(11) IE	(12) NL	(13) PL	(14) RO
Relative Price	1.352***	-0.123	1.336***	-0.926	-2.074***	1.459	-1.825*	-0.017	1.956***	4.889***	-0.661	-1.016	0.461***	-0.530*
	(0.334)	(0.398)	(0.488)	(0.951)	(0.791)	(0.939)	(0.932)	(0.327)	(0.652)	(1.304)	(0.903)	(0.907)	(0.139)	(0.295)
Relative Price Squared	-0.459***	0.050	-0.407**	0.386	0.806***	-0.454	0.643*	0.034	-0.628***	-1.620***	0.360	0.508	-0.144***	0.183*
	(0.119)	(0.142)	(0.173)	(0.324)	(0.270)	(0.317)	(0.350)	(0.117)	(0.224)	(0.457)	(0.306)	(0.321)	(0.047)	(0.104)
Relative Price Cubed	0.050***	-0.004	0.039**	-0.045	-0.097***	0.047	-0.066	-0.007	0.063***	0.175***	-0.047	-0.069*	0.014***	-0.020*
	(0.013)	(0.016)	(0.019)	(0.035)	(0.029)	(0.034)	(0.041)	(0.013)	(0.024)	(0.051)	(0.033)	(0.036)	(0.005)	(0.012)
Intermittent Renewables (GWh)	-0.129***	-0.062***	-0.024***	-0.159***	-0.020***	-0.120***	-0.074***	-0.059**	0.082***	-0.024***	-0.329***	-0.096***	-0.053***	-0.043***
	(0.018)	(0.017)	(0.001)	(0.011)	(0.003)	(0.016)	(0.025)	(0.023)	(0.030)	(0.005)	(0.016)	(0.011)	(0.001)	(0.005)
Load (GWh)	0.321***	0.208***	0.092***	0.161	0.098***	1.102***	0.152*	0.329**	0.169*	-0.014	-0.320***	0.265***	0.154***	0.361***
	(0.049)	(0.045)	(0.008)	(0.167)	(0.029)	(0.131)	(0.086)	(0.133)	(0.086)	(0.014)	(0.035)	(0.030)	(0.009)	(0.053)
Load Squared (GWh)	-0.020***	-0.005**	-0.001***	0.011	-0.001***	-0.038***	0.008	-0.051**	-0.006	0.000**	0.082***	-0.010***	-0.002***	-0.019***
	(0.004)	(0.002)	(0.000)	(0.017)	(0.000)	(0.006)	(0.006)	(0.026)	(0.008)	(0.000)	(0.009)	(0.001)	(0.000)	(0.003)
Observations	8,759	8,760	8,760	8,759	8,729	7,418	8,758	6,988	8,746	8,760	8,628	8,742	8,760	8,709
R-squared	0.919	0.821	0.818	0.600	0.657	0.856	0.312	0.277	0.156	0.598	0.559	0.743	0.916	0.520
Month FE	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES
Hour FE	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES
Day of Week FE	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES
Marginal Effect	0.203	0.0197	0.259	0.00214	-0.163	0.265	-0.172	0.0258	0.323	0.825	0.150	0.0882	0.0834	-0.0723

Robust standard errors in parentheses

*** p<0.01, ** p<0.05, * p<0.1

Supplementary Tab. 18: Estimates of main regression results of responsiveness of log-transformed coal generation factor to relative price (natural gas price/coal price), during April 1 2021-March 1 2022. The marginal effect, which is the estimate of interest, is derived through the delta method from the relative price coefficients, using the mean value of relative price during this period. Standard errors are clustered at the daily level, which is the unit of variation of the treatment variable. The statistical test used is the two-sided t-test. * indicates significance at the 10% level, ** indicates significance at the 5% level, and *** indicates significance at the 1% level.

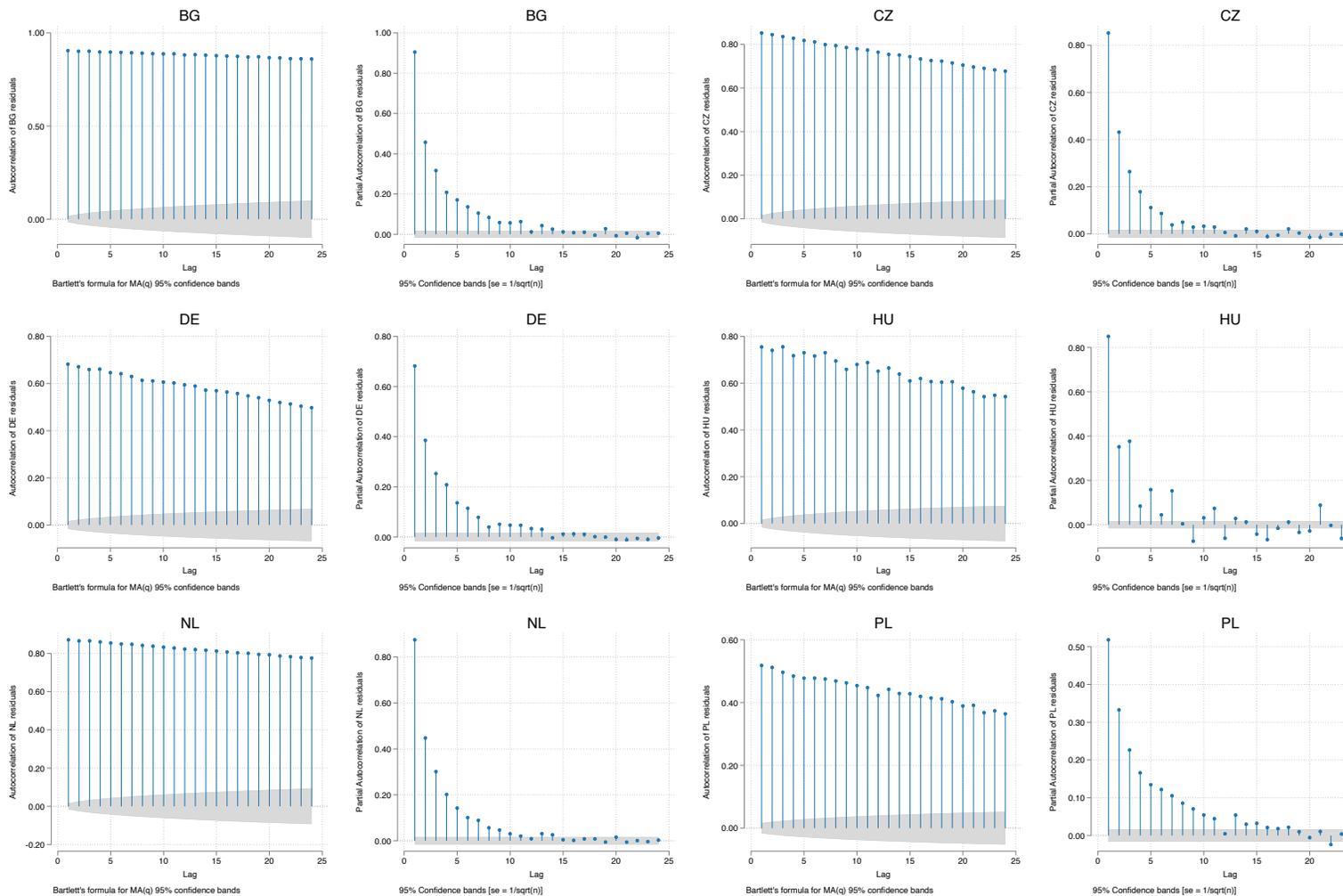
April 2021 - November 2021														
VARIABLES	(1) BG	(2) CZ	(3) DE	(4) DK	(5) ES	(6) FI	(7) GR	(8) HR	(9) HU	(10) IT	(11) IE	(12) NL	(13) PL	(14) RO
Relative Price	5.332*** (1.503)	-0.222 (1.561)	6.427*** (1.625)	2.839 (4.132)	-2.965 (2.345)	-8.630 (5.779)	6.334 (4.229)	1.534 (1.361)	11.992*** (3.230)	6.457* (3.588)	1.708 (3.387)	-0.092 (3.893)	1.596*** (0.530)	1.108 (1.251)
Relative Price Squared	-2.292*** (0.682)	0.093 (0.729)	-2.896*** (0.753)	-1.431 (1.973)	1.323 (1.175)	4.282 (2.601)	-1.490 (2.050)	-0.632 (0.638)	-5.487*** (1.488)	-1.599 (1.751)	-0.944 (1.607)	-0.001 (1.797)	-0.723*** (0.254)	-0.606 (0.582)
Relative Price Cubed	0.325*** (0.101)	-0.014 (0.111)	0.427*** (0.115)	0.231 (0.304)	-0.192 (0.187)	-0.676* (0.384)	0.077 (0.325)	0.081 (0.097)	0.823*** (0.224)	0.071 (0.275)	0.164 (0.251)	0.018 (0.271)	0.108*** (0.039)	0.091 (0.089)
Intermittent Renewables (GWh)	-0.130*** (0.031)	-0.054** (0.027)	-0.027*** (0.001)	-0.118*** (0.016)	-0.025*** (0.004)	-0.128*** (0.030)	-0.068** (0.030)	-0.048** (0.024)	0.020 (0.050)	-0.022*** (0.007)	-0.348*** (0.022)	-0.109*** (0.017)	-0.057*** (0.002)	-0.045*** (0.008)
Load (GWh)	0.425*** (0.086)	0.134*** (0.051)	0.097*** (0.009)	0.425* (0.247)	0.121*** (0.038)	1.110*** (0.221)	0.270** (0.105)	0.333* (0.192)	-0.103 (0.148)	-0.052*** (0.017)	-0.283*** (0.057)	0.261*** (0.044)	0.169*** (0.013)	0.299*** (0.079)
Load Squared (GWh)	-0.040*** (0.009)	-0.001 (0.003)	-0.001*** (0.000)	-0.021 (0.026)	-0.001** (0.001)	-0.038*** (0.011)	0.003 (0.007)	-0.070* (0.036)	0.014 (0.015)	0.001*** (0.000)	0.076*** (0.015)	-0.010*** (0.002)	-0.003*** (0.000)	-0.015*** (0.005)
Observations	5,856	5,856	5,856	5,856	5,842	4,514	5,856	4,359	5,842	5,856	5,765	5,838	5,856	5,805
R-squared	0.904	0.782	0.834	0.423	0.596	0.798	0.435	0.143	0.168	0.526	0.563	0.725	0.909	0.551
Month FE	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES
Hour FE	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES
Day of Week FE	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES
Marginal Effect	0.602	-0.0421	0.608	0.145	-0.279	-0.426	2.034	0.0923	1.086	1.742	0.0374	0.0657	0.156	-0.0937
Robust standard errors in parentheses														
*** p<0.01, ** p<0.05, * p<0.1														

Supplementary Tab. 19: Estimates of main regression results of responsiveness of log-transformed coal generation factor to relative price (natural gas price/coal price), during April 1 2021-October 31 2022. The marginal effect, which is the estimate of interest, is derived through the delta method from the relative price coefficients, using the mean value of relative price during this period. Standard errors are clustered at the daily level, which is the unit of variation of the treatment variable. The statistical test used is the two-sided t-test. * indicates significance at the 10% level, ** indicates significance at the 5% level, and *** indicates significance at the 1% level.

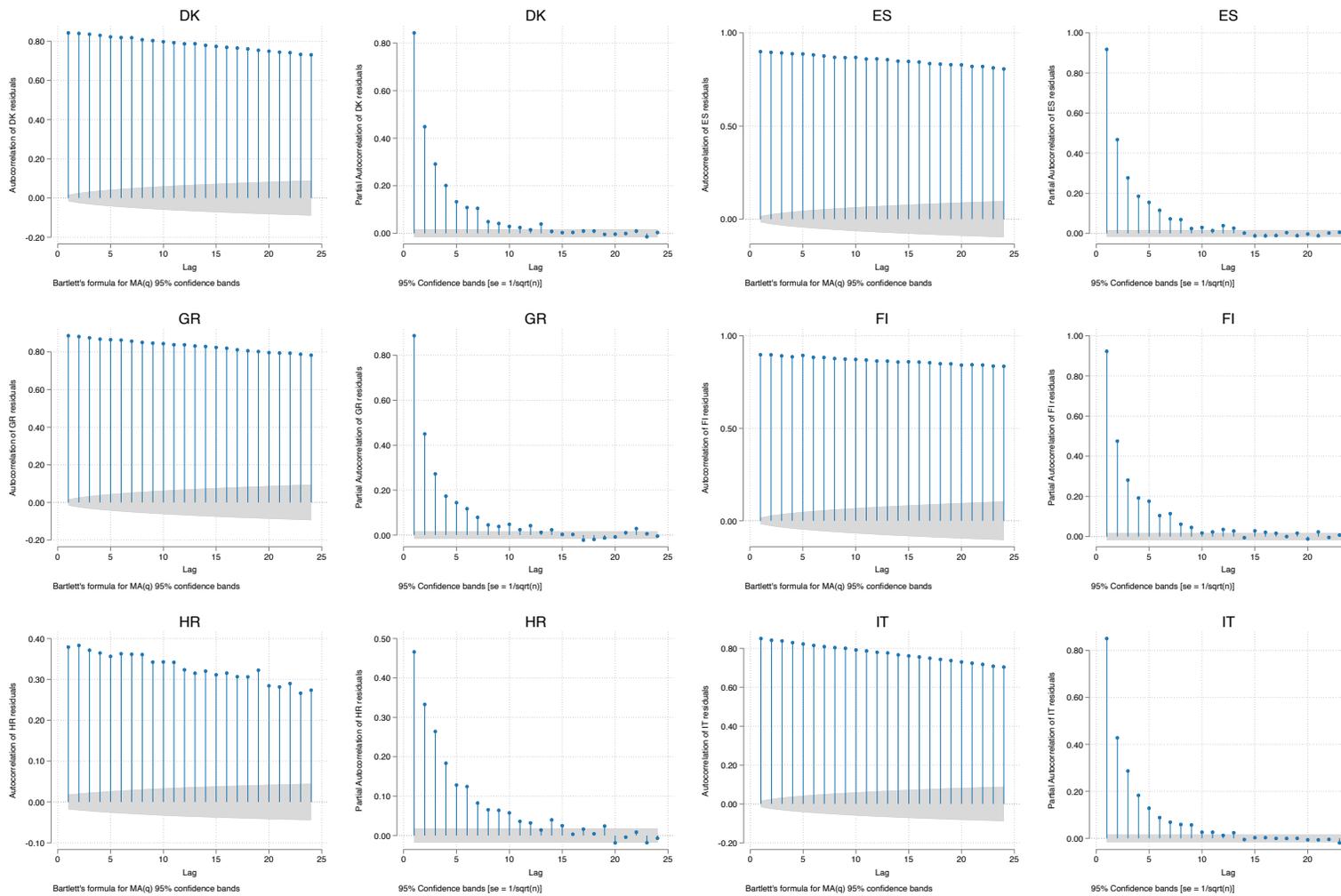
VARIABLES	(1) BG	(2) CZ	(3) DE	(4) DK	(5) ES	(6) FI	(7) GR	(8) HR	(9) HU	(10) IT	(11) IE	(12) NL	(13) PL	(14) RO
Relative Price	1.942*** (0.251)	1.131*** (0.271)	2.189*** (0.290)	1.103** (0.531)	4.190*** (0.567)	3.199*** (0.463)	-0.440 (0.860)	0.493 (0.423)	0.166 (0.277)	4.159*** (0.599)	-2.548*** (0.776)	-2.124*** (0.698)	0.532*** (0.078)	0.060 (0.196)
Relative Price Day Lagged	-0.001 (0.023)	0.098*** (0.035)	0.164*** (0.048)	0.119 (0.091)	0.258** (0.117)	0.057 (0.064)	0.329** (0.130)	0.095** (0.038)	-0.048 (0.044)	0.132* (0.071)	0.209*** (0.079)	0.176** (0.084)	0.032*** (0.011)	0.025 (0.027)
Intermittent Renewables (GWh)	-0.151*** (0.019)	-0.056*** (0.017)	-0.024*** (0.001)	-0.157*** (0.010)	-0.024*** (0.004)	-0.063*** (0.018)	-0.063*** (0.024)	-0.066*** (0.023)	0.057** (0.026)	-0.040*** (0.005)	-0.336*** (0.016)	-0.111*** (0.012)	-0.055*** (0.001)	-0.056*** (0.006)
Load (GWh)	0.313*** (0.045)	0.123*** (0.044)	0.076*** (0.008)	0.081 (0.162)	0.041 (0.034)	0.690*** (0.123)	0.447*** (0.086)	0.229** (0.112)	0.171** (0.076)	0.042** (0.018)	0.081 (0.050)	0.263*** (0.023)	0.135*** (0.009)	0.431*** (0.045)
Load Squared (GWh)	-0.020*** (0.004)	-0.001 (0.002)	-0.000*** (0.000)	0.015 (0.016)	-0.000 (0.001)	-0.021*** (0.006)	-0.011* (0.006)	-0.033 (0.022)	-0.006 (0.007)	-0.000 (0.000)	0.013 (0.010)	-0.010*** (0.001)	-0.002*** (0.000)	-0.023*** (0.003)
Observations	10,199	10,200	10,200	10,199	10,169	8,858	10,189	7,957	10,186	10,224	9,950	10,182	10,200	10,149
R-squared	0.896	0.784	0.812	0.556	0.551	0.825	0.396	0.218	0.143	0.533	0.635	0.734	0.912	0.497
Month FE	YES	YES	YES	YES	YES	YES	YES							
Hour FE	YES	YES	YES	YES	YES	YES	YES							
Day of Week FE	YES	YES	YES	YES	YES	YES	YES							
Marginal Effect	0.255***	0.227***	0.417***	0.308***	0.713***	0.467***	0.196**	0.113*	0.0432	0.758***	0.0218	0.0994	0.103***	0.0166
SE	Day clustered	Day Clustered	Day Clustered	Day Clustered	Day Clustered	Day Clustered	Day Clustered							

Supplementary Tab. 20: Estimates of main regression results of responsiveness of log-transformed coal generation factor to relative price (natural gas price/coal price), including a lagged relative price regressor (1 day; 24 hours). The marginal effect, which is the estimate of interest, is derived through the delta method from the relative price coefficients, using the mean value of relative price during this period. Standard errors are clustered at the daily level, which is the unit of variation of the treatment variable. The statistical test used is the two-sided t-test. * indicates significance at the 10% level, ** indicates significance at the 5% level, and *** indicates significance at the 1% level.

Pooled Regression	
	<u>Log Coal Generation</u>
Relative Price	0.696 (0.768)
Intermittent Renewables (GWh)	-0.024*** (0.003)
Load (GWh)	0.082** (0.031)
Load Squared (GWh)	-0.001* (0.000)
Marginal Effect	0.212** (0.0917)
Observations	139,174
Number of Countries	14
R-squared	0.313
Country FE	YES
Month FE	YES
Hour FE	YES
Day of Week FE	YES
SE	Day Clustered



Supplementary Tab. 22: Autocorrelation (ACF; left) and Partial Autocorrelation (PACF; right) of the main regression residuals for six countries. These display clear intraday serial dependence, justifying the choice of clustered standard errors at the day level. The rapid decay of the PACF after the first few hours reflects the appropriate generation dynamics of hourly fuel-switching.



Supplementary Tab. 23: Autocorrelation (ACF; left) and Partial Autocorrelation (PACF; right) of the main regression residuals for six countries. These display clear intraday serial dependence, justifying the choice of clustered standard errors at the day level. The rapid decay of the PACF after the first few hours reflects the appropriate generation dynamics of hourly fuel-switching.

Pooled Regression (with ETS Price)	
	<u>Log Coal Generation</u>
Relative Price	0.882 (0.513)
ETS Carbon Price	-0.001 (0.002)
Intermittent Renewables (GWh)	-0.024*** (0.003)
Load (GWh)	0.082** (0.031)
Load Squared (GWh)	-0.001* (0.000)
Marginal Effect	0.234*** (0.0722)
Observations	139,174
Number of Countries	14
R-squared	0.313
Country FE	YES
Month FE	YES
Hour FE	YES
Day of Week FE	YES
SE	Day Clustered

	(1) BG	(2) CZ	(3) DE	(4) DK	(5) ES	(6) FI	(7) GR	(8) HR	(9) HU	(10) IT	(11) IE	(12) NL	(13) PL	(14) RO
Relative Price	1.111*** (0.141)	0.554*** (0.145)	1.083*** (0.112)	0.281 (0.187)	1.833*** (0.278)	0.783*** (0.140)	-0.307 (0.232)	3.202*** (0.602)	-0.032 (0.141)	1.710*** (0.258)	-0.638* (0.368)	-0.755*** (0.226)	0.349*** (0.043)	-0.010 (0.130)
Relative Price Squared	-0.387*** (0.055)	-0.186*** (0.060)	-0.351*** (0.045)	-0.065 (0.077)	-0.593*** (0.110)	-0.267*** (0.055)	0.138 (0.096)	-1.048*** (0.233)	0.028 (0.054)	-0.562*** (0.105)	0.298** (0.132)	0.384*** (0.094)	-0.111*** (0.016)	0.006 (0.050)
Relative Price Cubed	0.043*** (0.007)	0.022*** (0.007)	0.037*** (0.006)	0.007 (0.010)	0.060*** (0.014)	0.030*** (0.006)	-0.016 (0.012)	0.109*** (0.028)	-0.005 (0.006)	0.061*** (0.013)	-0.037** (0.015)	-0.052*** (0.012)	0.011*** (0.002)	-0.001 (0.006)
IRE (GWh)	-0.102*** (0.011)	-0.030*** (0.008)	-0.012*** (0.000)	-0.061*** (0.004)	-0.010*** (0.002)	-0.029*** (0.005)	-0.028*** (0.007)	-0.086 (0.054)	0.030** (0.015)	-0.017*** (0.002)	-0.124*** (0.007)	-0.043*** (0.005)	-0.033*** (0.001)	-0.035*** (0.004)
Load (GWh)	0.118*** (0.026)	0.011 (0.023)	0.032*** (0.003)	-0.040 (0.050)	0.025*** (0.009)	-0.105*** (0.024)	0.090*** (0.026)	0.261 (0.197)	0.102** (0.041)	0.019*** (0.007)	0.024 (0.027)	0.057*** (0.009)	0.048*** (0.004)	0.167*** (0.006)
Load Squared (GWh)	-0.003 (0.002)	0.003** (0.001)	-0.000*** (0.000)	0.014** (0.005)	-0.000** (0.000)	0.010*** (0.001)	0.002 (0.002)	-0.040 (0.038)	-0.004 (0.004)	-0.000 (0.000)	0.011** (0.005)	-0.001*** (0.000)	-0.000*** (0.000)	-0.007*** (0.001)
Marginal Effect	0.154 (0.018)	0.106 (0.014)	0.191 (0.012)	0.113 (0.020)	0.303 (0.041)	0.127 (0.017)	0.028 (0.015)	0.531 (0.078)	0.011 (0.018)	0.310 (0.028)	0.053 (0.054)	0.087 (0.024)	0.062 (0.006)	0.001 (0.016)
Observations	10,224	10,224	10,224	10,224	10,224	10,224	10,224	10,224	10,224	10,224	10,224	10,224	10,224	10,224
R-squared	0.888	0.815	0.870	0.628	0.523	0.887	0.429	0.567	0.187	0.552	0.554	0.752	0.929	0.582
Month FE	YES	YES	YES	YES	YES	YES	YES							
Hour FE	YES	YES	YES	YES	YES	YES	YES							
Day of Week FE	YES	YES	YES	YES	YES	YES	YES							

Clustering standard errors on day in parentheses
*** p<0.01, ** p<0.05, * p<0.1

Supplementary Tab. 25: Estimates of regression results for an alternative dependent variable of coal capacity factor (generation/installed capacity) responsiveness to relative price (natural gas price/coal price). Marginal effect derived through the delta method from the relative price coefficients is our estimate of interest. The statistical test used is the two-sided t-test. * indicates significance at the 10% level, ** indicates significance at the 5% level, and *** indicates significance at the 1% level.

1.3.2 Econometric Model of Pass-Through

To examine the robustness our pass-through estimate results that we use for the policy counterfactual analysis over the period of 2022, we shorten the time period of these regressions to the 11 months of 2022, omitting 2021 (Supp. Fig 21). With the exception of Romania (and to an extent Bulgaria and Spain), all pass-through coefficients are remarkably similar in each regression subsample (see Extended Data Fig. 6 for the main sample estimates). In the case of Romania and Bulgaria, one can speculate that there may be either significant changes in the capacity mix or manipulative bidding occurring during 2022, while in Spain the announcement of the so-called "Iberian exception" of natural gas pricing may play a role. Similarly, a robustness check is conducted for the sample of January 2021-January 2023, in which the results are also qualitatively similar (Supp. Fig. 22). A further detailed analysis of robustness checks of natural gas price-through during the energy crisis can be found in [Bajo-Buenestado et al., 2005].

	BG	CZ	DE	DK	ES	FI	GR	HR	HU	IT	NL	PL	RO
NG Price (EUR/MWh)	1.251*** (0.137)	1.709*** (0.129)	1.717*** (0.128)	1.783*** (0.147)	0.586*** (0.130)	0.713*** (0.208)	1.436*** (0.107)	1.935*** (0.134)	1.896*** (0.128)	1.792*** (0.126)	1.862*** (0.129)	0.494*** (0.098)	1.819*** (0.123)
IRE (GWh)	-94.697*** (14.197)	-78.342*** (7.791)	-6.180*** (0.213)	-40.326*** (2.009)	-5.225*** (0.378)	-51.336*** (4.372)	-28.427*** (2.657)	-39.218*** (9.282)	-16.508** (8.063)	-6.516*** (0.922)	-25.789*** (2.036)	-18.968*** (0.871)	-41.489*** (3.202)
Load (GWh)	96.062*** (31.518)	69.450*** (16.082)	12.793*** (1.618)	53.288** (23.451)	6.237* (3.313)	167.227*** (27.577)	28.011** (14.091)	185.979*** (59.241)	178.898*** (32.371)	6.208*** (2.062)	49.104*** (5.723)	38.107*** (5.212)	-22.897** (10.091)
Load Sq. (GWh)	-2.719 (3.291)	-2.420** (0.984)	-0.072*** (0.013)	-3.042 (2.608)	-0.008 (0.057)	-6.328*** (1.367)	-0.140 (1.121)	-7.942 (12.617)	-11.830*** (3.072)	0.018 (0.029)	-1.704*** (0.271)	-0.719*** (0.129)	5.902*** (0.839)
Observations	7,680	7,680	7,680	7,680	7,680	7,680	7,680	7,680	7,680	7,680	7,680	7,680	7,680
R-squared	0.681	0.796	0.875	0.803	0.718	0.524	0.680	0.826	0.813	0.884	0.816	0.692	0.814
Month FE	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES
Hour FE	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES
Day of Week FE	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES

Clustered standard errors on day in parentheses. Sample: January 2022-November 2022
*** p<0.01, ** p<0.05, * p<0.1

Supplementary Tab. 26: Pass-through results for all countries across our main specification, but for a different period of January 2022-December 2022. Pass-through coefficients and standard errors (in parenthesis) displayed for every country. The natural gas price coefficient represents the impact of an increase in the price of natural gas (in EUR/MWh) on the wholesale electricity price (in EUR/MWh) for each country. The statistical test used is the two-sided t-test. * indicates significance at the 10% level, ** indicates significance at the 5% level, and *** indicates significance at the 1% level.

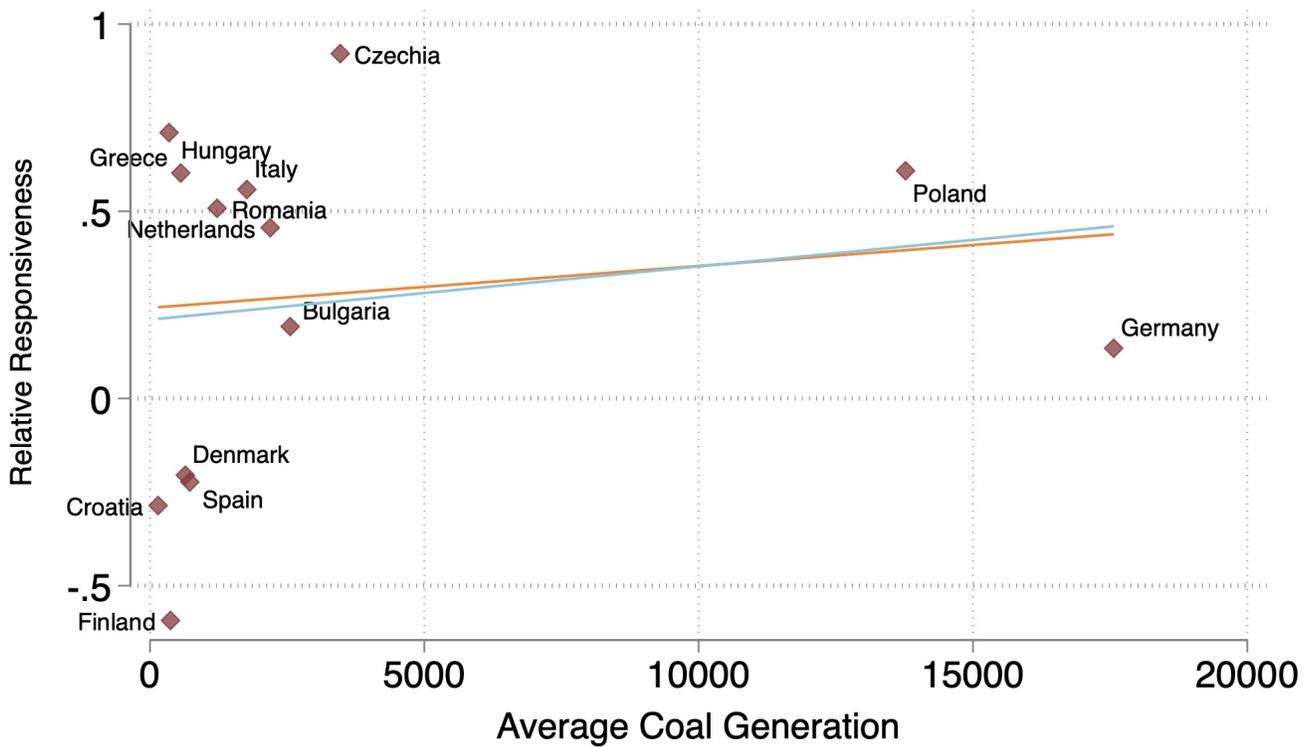
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	BG	CZ	DE	DK	ES	FI	HR	HU	IT	NL	PL	RO
Natural Gas Price (EUR/GWh)	1.117*** (0.0415)	1.866*** (0.0373)	1.872*** (0.0354)	1.711*** (0.0409)	0.773*** (0.0452)	1.028*** (0.0547)	1.946*** (0.0349)	1.987*** (0.0355)	2.060*** (0.0302)	1.856*** (0.0316)	0.986*** (0.0310)	1.300*** (0.0693)
Intermittent Renewables (GWh)	-75.65*** (10.49)	-59.31*** (4.789)	-4.404*** (0.161)	-30.61*** (1.333)	-5.886*** (0.477)	-32.58*** (2.877)	-16.95*** (6.426)	-11.34** (4.929)	-5.261*** (0.648)	-18.86*** (1.266)	-12.58*** (0.695)	-19.40*** (3.756)
Load (GWh)	161.7*** (29.38)	56.93*** (10.60)	9.540*** (1.210)	27.57* (16.25)	16.44*** (4.351)	38.98* (20.41)	176.6*** (42.57)	107.8*** (24.27)	5.976*** (1.604)	42.91*** (4.164)	11.32** (4.597)	-50.46*** (5.715)
Load Squared (GWh)	-5.382* (3.058)	-1.684** (0.655)	-0.0432*** (0.00996)	1.321 (1.809)	-0.196*** (0.0723)	-0.348 (1.024)	-11.35 (9.408)	-5.174** (2.274)	0.00174 (0.0225)	-1.356*** (0.189)	-0.103 (0.117)	8.362*** (0.641)
Observations	16,440	16,440	16,440	16,440	16,440	16,440	16,440	16,440	16,440	16,440	16,440	16,440
R-squared	0.690	0.833	0.869	0.801	0.520	0.535	0.864	0.856	0.908	0.842	0.698	0.513
Month FE	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES
Hour FE	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES
Day of Week FE	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES

Clustered Robust standard errors on day in parentheses *** p<0.01, ** p<0.05, * p<0.1

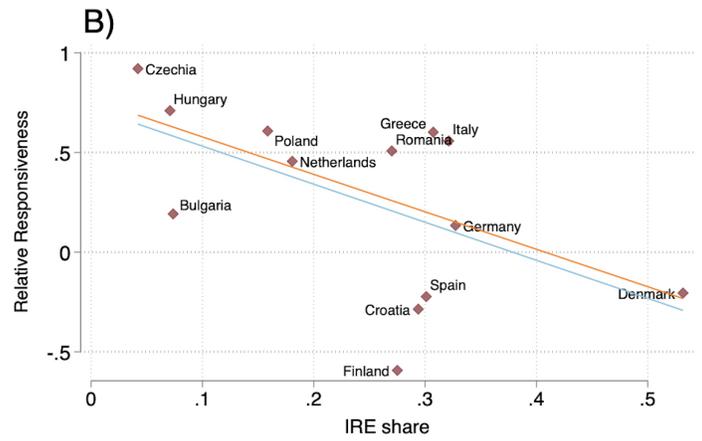
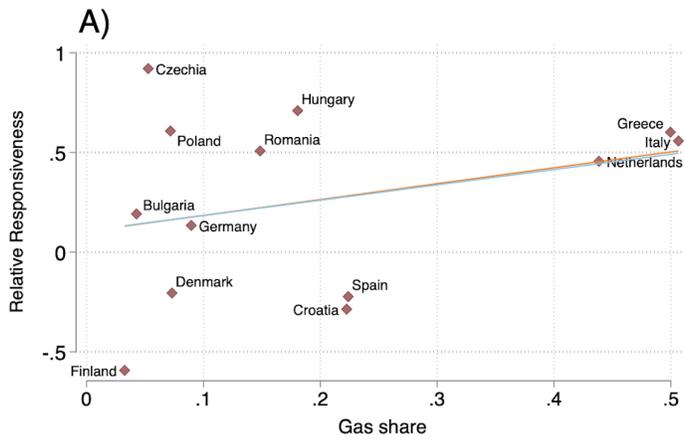
Supplementary Tab. 27: Pass-through results for all countries during a sample period of January 2021-January 2023. Pass-through coefficients and standard errors (in parenthesis) displayed for every country. The natural gas price coefficient represents the impact of an increase in the price of natural gas (in EUR/MWh) on the wholesale electricity price (in EUR/MWh) for each country. The statistical test used is the two-sided t-test. * indicates significance at the 10% level, ** indicates significance at the 5% level, and *** indicates significance at the 1% level.

1.3.3 Relative Responsiveness Index

Here we provide additional information in regards to the relative responsiveness index. The index quantifies the relationship between coal responsiveness and the pass-through of gas prices to electricity prices, capturing how shifts in relative fuel costs affect the balance of coal and gas generation. It is calculated as the correlation between hourly marginal effects of coal generation with respect to the relative price and the hourly pass-through of gas prices to electricity. A more positive value (after negating the index) reflects a stronger substitutability between coal and gas, where increases in gas prices lead to significant coal generation adjustments, typically seen in systems with higher shares of coal and gas in the generation mix (Supp. Fig 1 & Supp. Fig 2). Conversely, a negative or near-zero RRI suggests weaker substitution, potentially due to structural factors like high shares of IRE or decarbonized energy (Supp. Fig 2 & Fig 4), which act as an alternative, or operational constraints that limit switching flexibility. By focusing on hourly dynamics, the index accounts for variations in market conditions (e.g., peak vs. off-peak hours) and provides a consistent framework to assess how the interplay of coal and natural gas generation responds to changing fuel prices.



Supplementary Fig. 1: Relative Responsiveness relationship with absolute coal generation (MWh) across countries. Scatter plots include a fitted line of a linear regression estimated via OLS (blue line), and a fitted line estimated using the robust MM-estimator (orange line). The robust MM-estimator is preferred when the data has outliers and likely-influential but non-representative points [Kaffine and Davis, 2017].



Supplementary Fig. 2: A) Relative Responsiveness relationship with natural gas energy generation across countries. B) Relative Responsiveness relationship with IRE generation across countries.

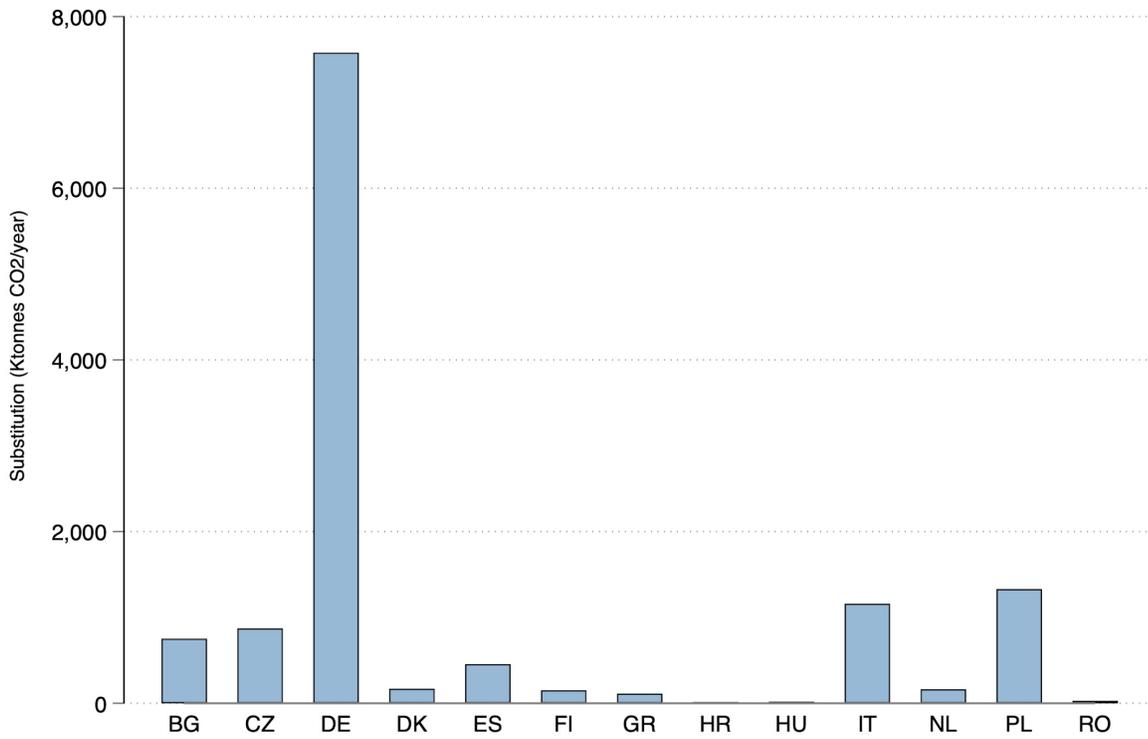
1.3.4 Policy analysis

Our carbon equivalent levy is calculated from the following equation:

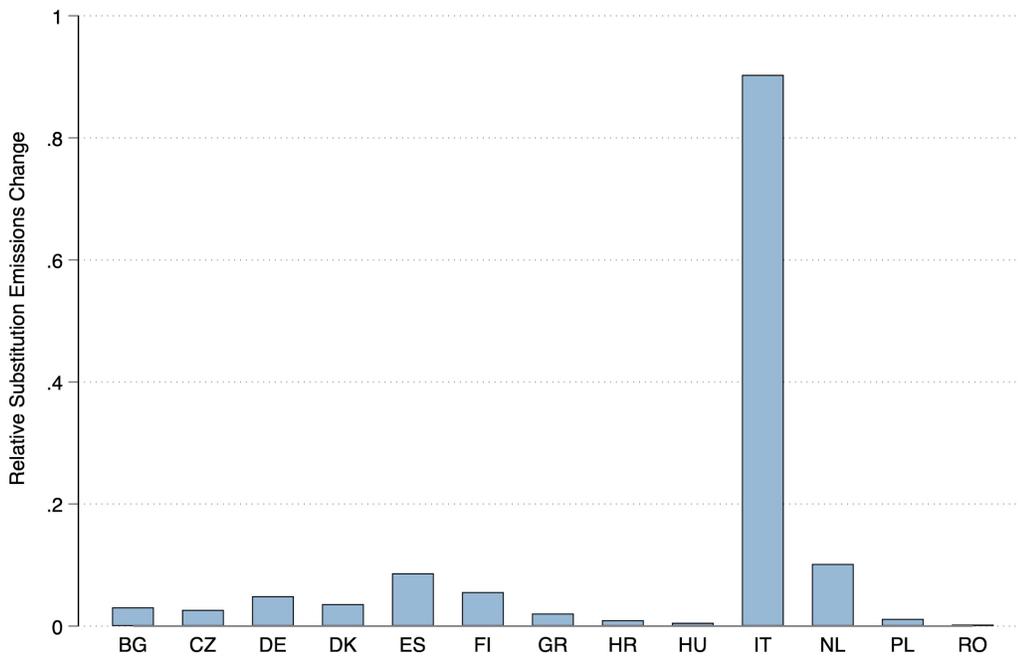
$$\mathbb{E}_{2022} \left[\frac{P_{\text{Gas}} + (P_{\text{ETS}} + \Delta C) EF_{\text{Gas}}}{P_{\text{Coal}} + (P_{\text{ETS}} + \Delta C) EF_{\text{Coal}}} \right] = \mathbb{E}_{2022, \text{GasCap}}[\text{Relative Price}] \quad (1)$$

where ΔC is found to be 12.18 EUR/tonne. The right-hand side mean relative price of 2022 in this way is equated to the mean relative price of 2022 under the hypothetical scenario of the 180 EUR/MWh natural gas cap being imposed. EF refer to emissions factor of gas and coal, in which gas is 0.37 times as carbon intensive as coal. As mentioned in the methods, the process for finding this value was an iterative loop of incremental ΔC values by 0.01, until the absolute difference between both sides of the equation were closest as possible to zero.

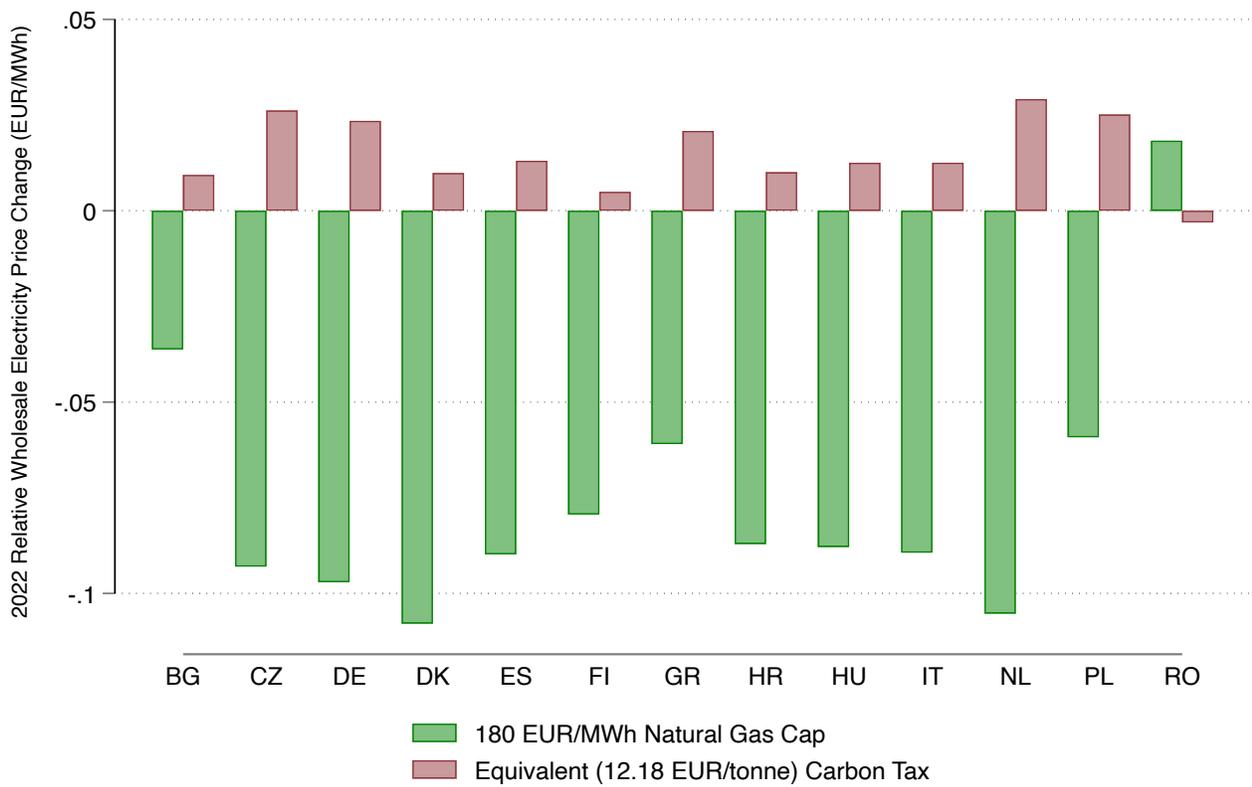
Below we provided additional information on the two studied hypothetical policy effects during 2022.



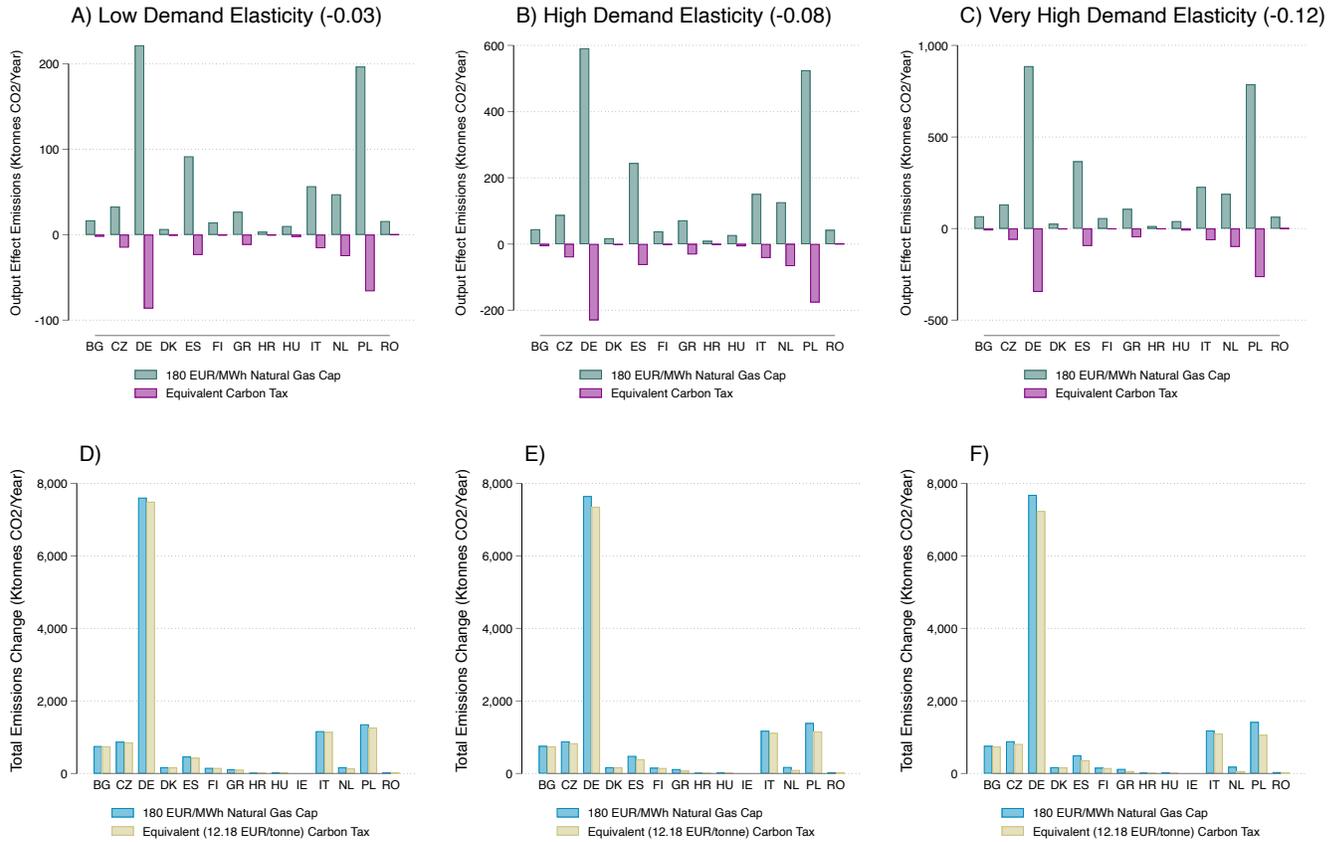
Supplementary Fig. 3: Substitution effect across countries under the 180 EUR/MWh natural gas price cap and equivalent 12.18 EUR/tonne carbon levy in 2022.



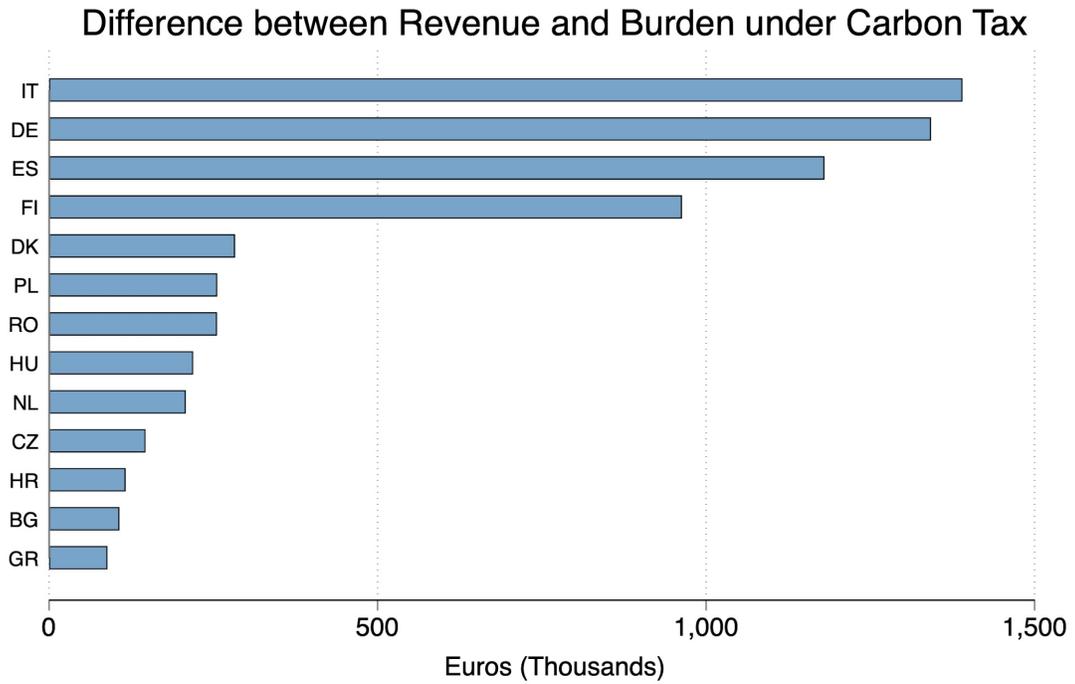
Supplementary Fig. 4: Substitution effect across countries under the 180 EUR/MWh natural gas price cap and equivalent 12.18 EUR/tonne carbon levy in 2022, in relation to baseline (January-April 2021 pre-crisis) emissions.



Supplementary Fig. 5: Wholesale electricity price change across countries under the two policies in 2022, in relation to baseline (January-April 2021 pre-crisis) prices.



Supplementary Fig. 6: Output Effect emissions change under different elasticity of demand assumptions for natural gas cap and equivalent carbon tax policies. Since our output effect estimate relies on our electricity elasticity of demand assumption, we examine this effect under three different values of elasticity. As expected, these estimates vary considerably but always are less than the substitution effect. While results are evidently qualitatively similar between countries, the magnitude varies considerably depending on this assumption **A)** The low demand of elasticity refers to -0.03 , in comparison to -0.06 which is used in the main Figure 5. The total emissions effect (addition of the substitution effect) is depicted in panel (D). **B)** The high demand of elasticity refers to -0.08 , in comparison to 0.06 which is used in the main Figure 5. The total emissions effect (addition of the substitution effect) is depicted in Panel (E) **C)** The very high demand of elasticity refers to -0.12 , in comparison to 0.15 which is used in the main Figure 5. The total emissions effect (addition of the substitution effect) is depicted in Panel (F).



Supplementary Fig. 7: Difference between revenue generated from the emergency carbon levy and burden on consumers from higher electricity prices. This is calculated by subtracting the pink bars from the gray bars in Figure 5 Panel D

2 Supplementary Figures

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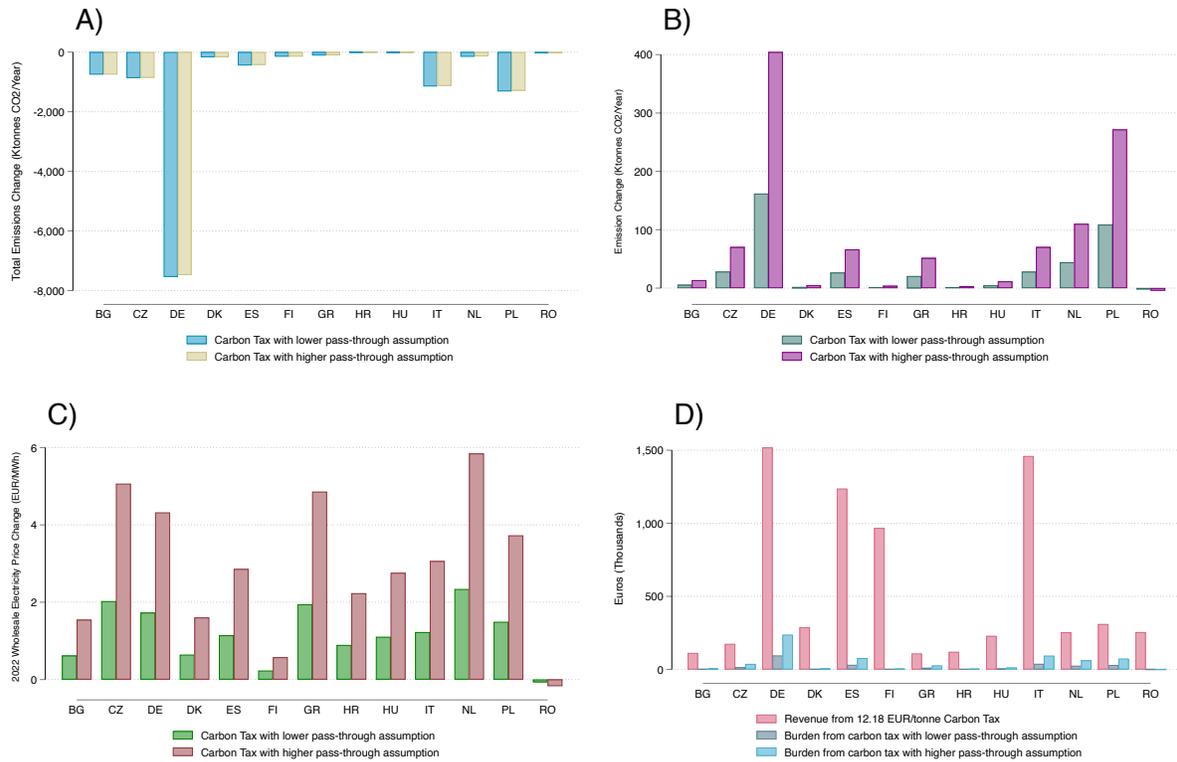


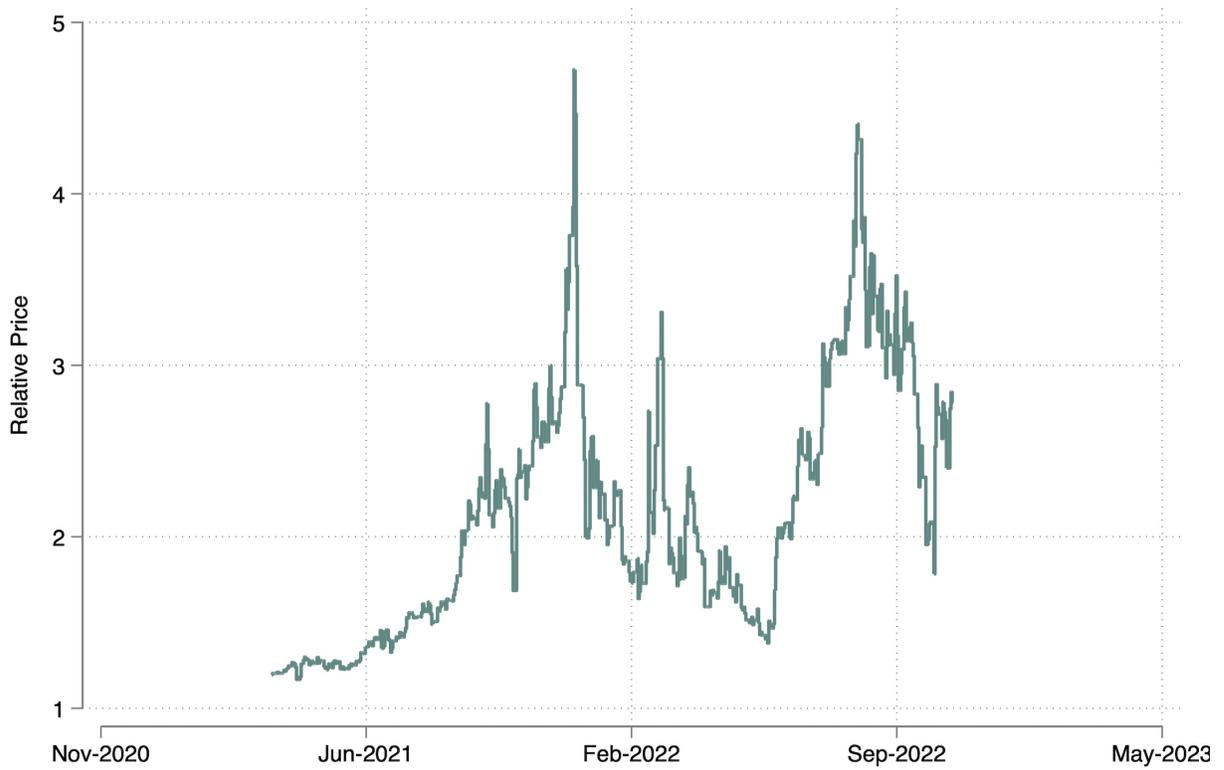
Figure 8: Policy counterfactual analysis: Different assumptions for the level of pass-through of the carbon price to electricity price during 2022. As our estimated pass-through reflects the pass-through of natural gas prices to wholesale electricity prices (which is the most common price-setter on the margin), our main analysis assumes that 0.37 of this pass-through is passed-through via a 1 euro/tonne increase in carbon price. We thus also estimate the increased electricity price from the carbon levy under a higher pass-through assumption (0.5) or a lower one (0.2). **A)** Comparison of wholesale electricity price change under each carbon tax assumption per country. **B)** Comparison of the change in revenue and financial burden and relief of each carbon tax assumption per country. The burden from the additional carbon pass-through and the revenues that could be used for consumer relief is shown. All values are normalized by average load per country, while the revenue and burden are adjusted with country specific emissions factors. **C)** Comparison of underlying output effect and substitution effect under each carbon tax assumption per country. The output effect per country is calculated using electricity price pass-through estimates and assumed elasticity of demand (-0.06), based on prior literature. **D)** Comparison of total emissions change under each carbon tax assumption per country, including the substitution and output effect.

Country Selection

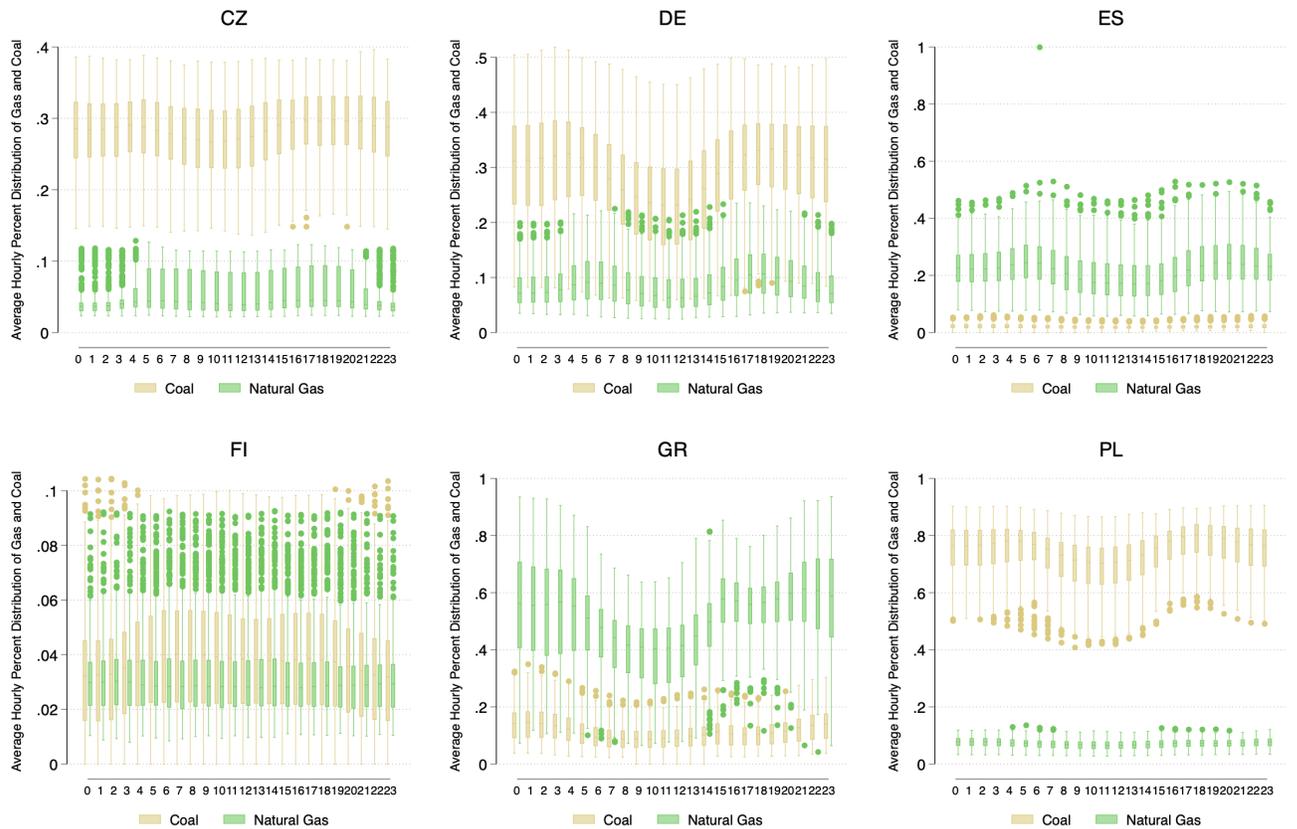
EU Countries	Code	Present?	Reason for Absence
Austria	AT		No coal
Belgium	BE		No coal
Bulgaria	BG	y	
Croatia	HR	y	
Republic of Cyprus	CY		No coal
Czech Republic	CZ	y	
Denmark	DK	y	
Estonia	EE		Small quantity of coal-derived gas
Spain	ES	y	
Finland	FI	y	
France	FR		Small quantity of coal, mostly nuclear
Germany	DE	y	
Greece	GR	y	
Hungary	HU	y	
Ireland	IE	y	
Italy	IT	y	
Latvia	LV		No coal
Lithuania	LT		No coal
Luxembourg	LU		No coal
Malta	MT		No data
Netherlands	NL	y	
Poland	PL	y	
Portugal	PT		Small quantity of coal
Romania	RO	y	
Slovakia	SK		Small quantity of coal, mostly nuclear
Slovenia	SI		Small quantity of gas
Sweden	SE		No coal

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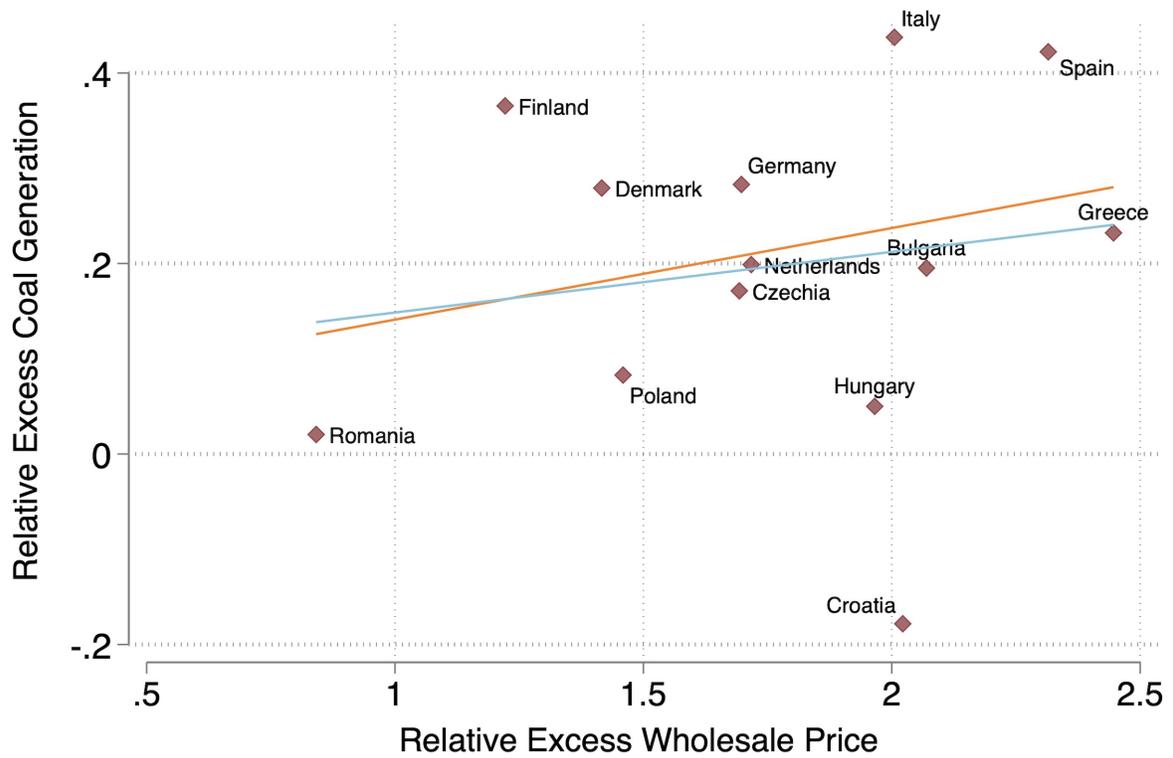
Figure 9: Explanation of country selection for our analysis. Requirements include the significant presence of coal and natural gas generation and evidently adequate non-missing data.



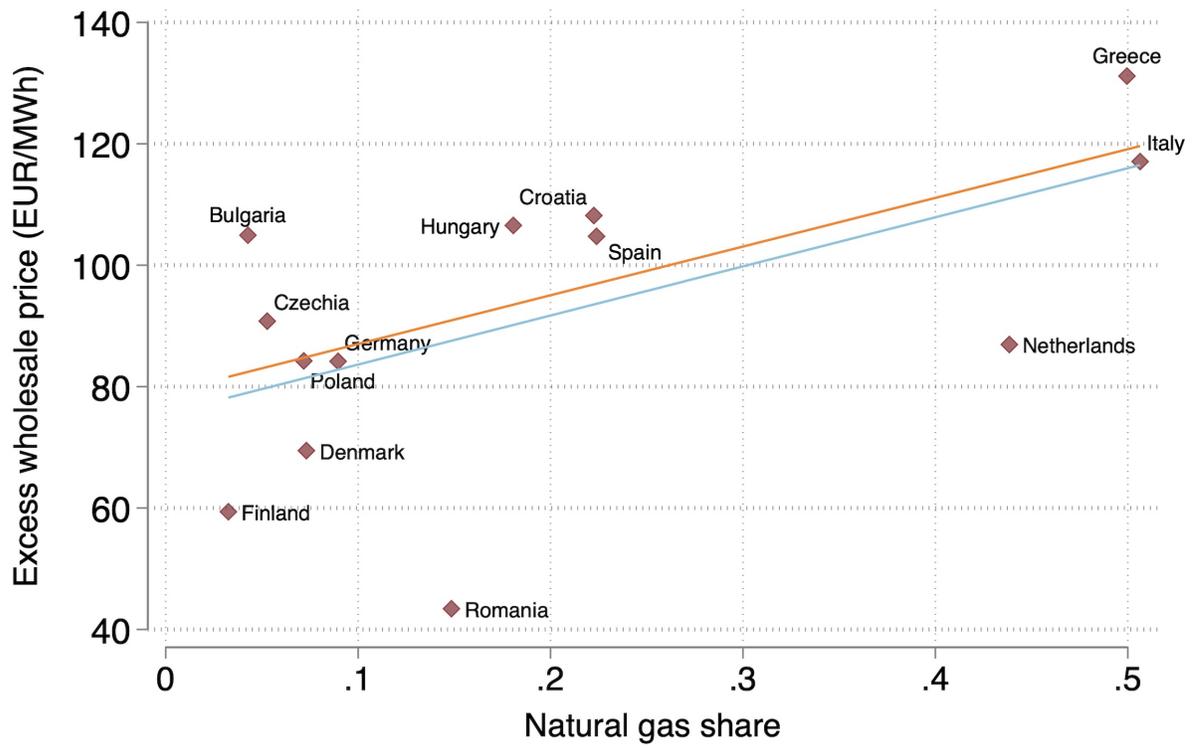
Supplementary Fig. 10: Timeseries of the EU relative (natural gas/coal) price from January 2021 to December 2022, inclusive of carbon prices.



Supplementary Fig. 11: The hourly distribution of coal and natural gas energy generation (as a share) for our subset of countries, with vertical box plots capturing the $\pm 1.5 \times \text{IQR}$ (the interquartile range) with bounds at the 25th percentile (Q1) and 75th percentile (Q3). The center line of the box represents the median (50th percentile). Whiskers extend to the smallest and largest values within $1.5 \times \text{IQR}$ of the lower and upper quartiles, respectively, while dots correspond to the outliers outside this range.



Supplementary Fig. 12: Relationship of excess coal with excess wholesale electricity price across countries, both in relative terms (using the January-April 2021 pre-crisis average as a baseline).



Supplementary Fig. 13: Relationship of excess wholesale electricity price across countries, in relationship to natural gas share.

Excess Coal Generation (Higher Relative Price)

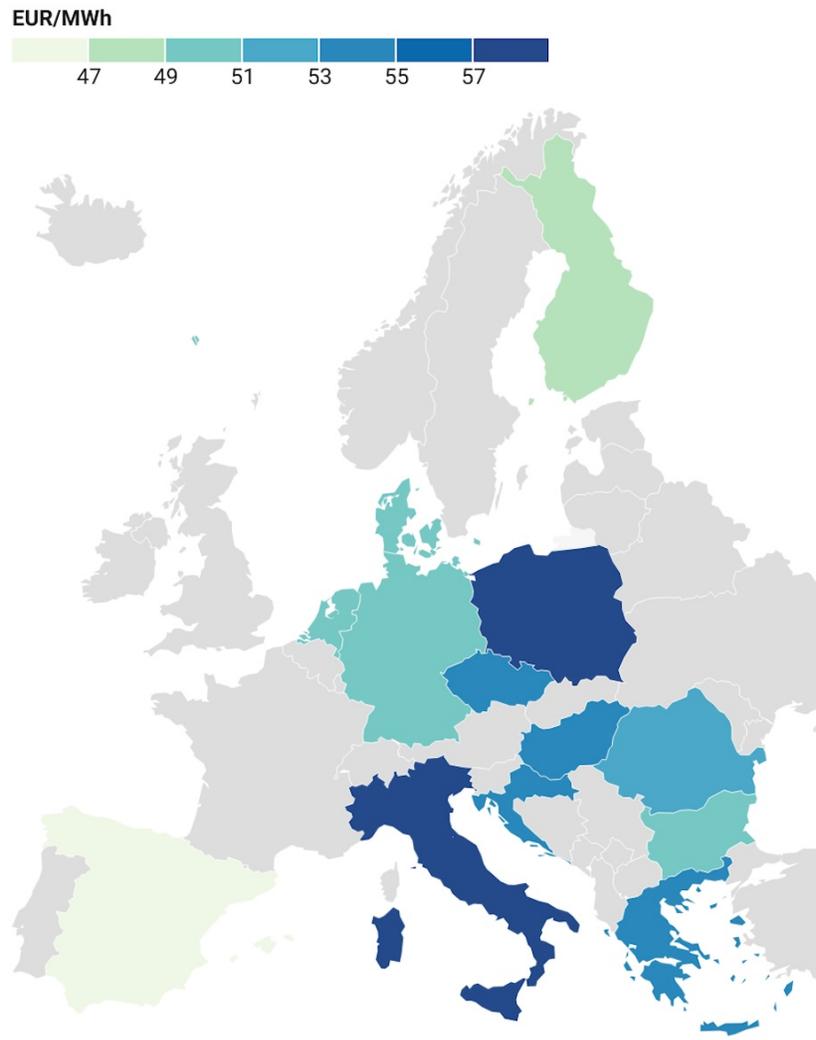


Supplementary Fig. 14: Excess coal and lignite generation during April 1 2021 - May 30 2022, using a higher counterfactual relative price (compared to the actual January-April 2021) during the pre-crisis period. Excess coal refers to the additional amount of coal generated in surplus of the predicted coal under "non-crisis price environment." This is calculated by subtracting the estimated amount of coal generated under counterfactual scenario where relative gas prices are equivalent to the pre-crisis period January - March 2021 (the 3rd quartile) – from the actual observed coal generation (panel D), as discussed in Methods.

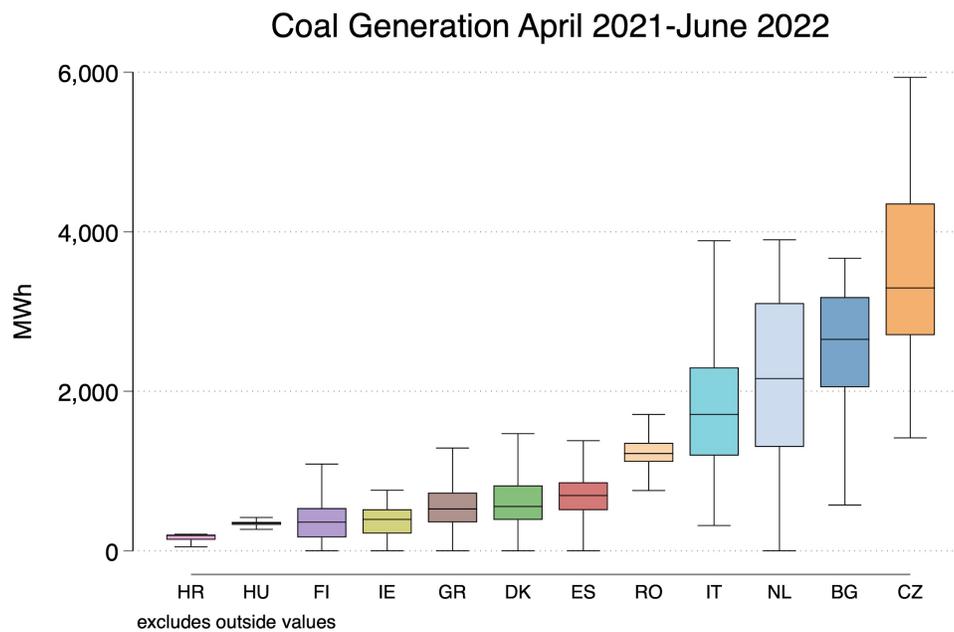
Excess Coal Generation (Lower Relative Price)



Supplementary Fig. 15: Excess coal and lignite generation during April 1 2021 - May 30 2022, using a lower counterfactual relative price (compared to the actual January-April 2021) during the pre-crisis period. Excess coal refers to the additional amount of coal generated in surplus of the predicted coal under "non-crisis price environment." This is calculated by subtracting the estimated amount of coal generated under counterfactual scenario where relative gas prices are equivalent to the pre-crisis period January - March 2021 (the 1st quartile) – from the actual observed coal generation (panel D), as discussed in Methods.

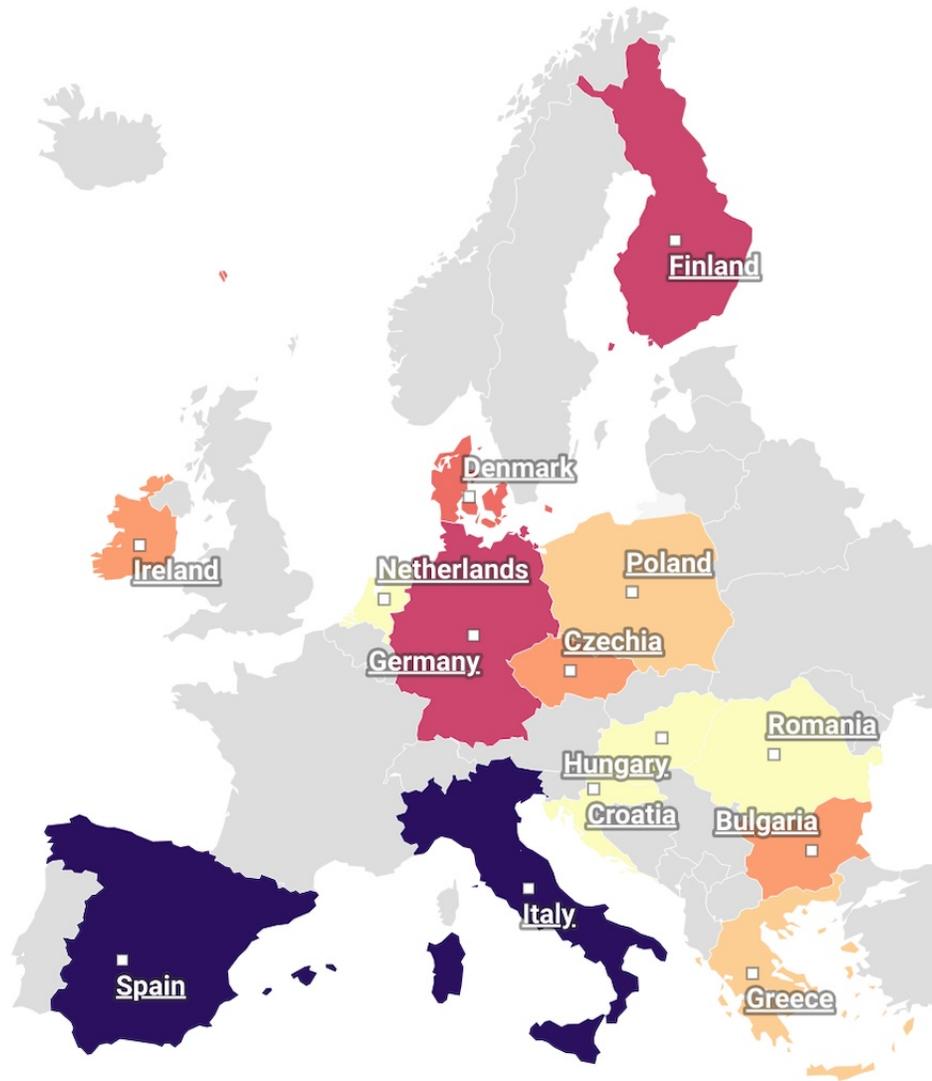


Supplementary Fig. 16: Pre-crisis wholesale electricity prices (January-April 2021) across sample countries.

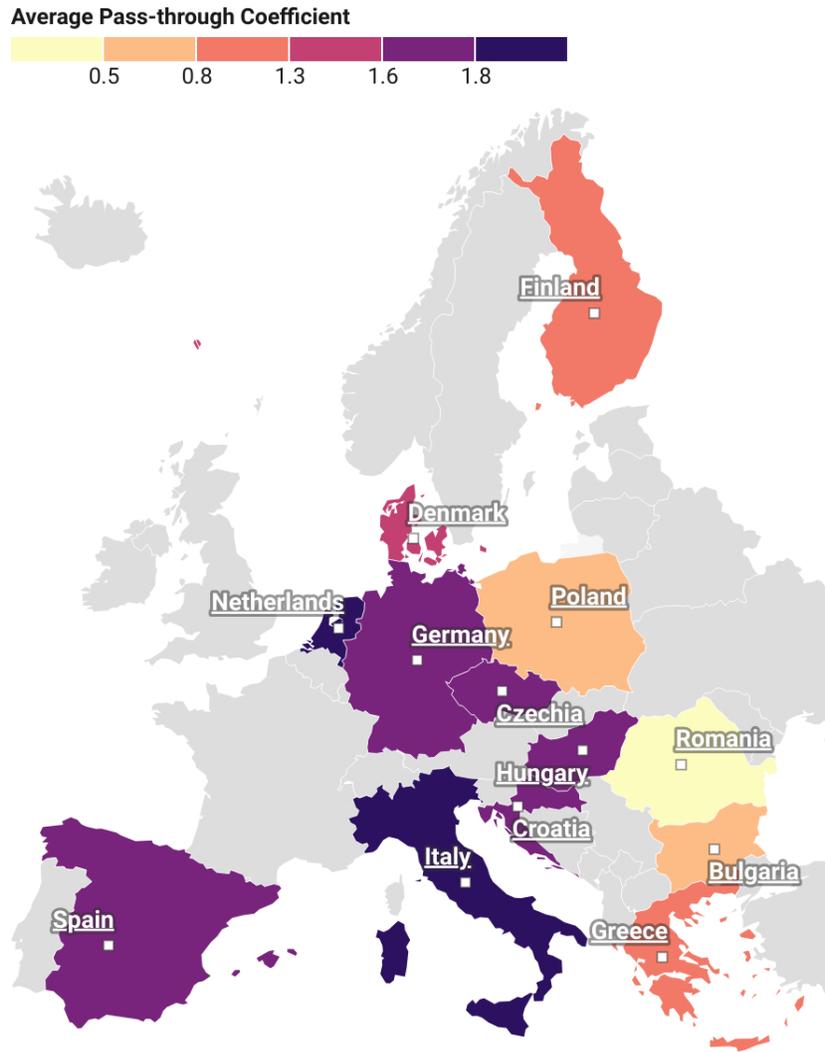


Supplementary Fig. 17: Distribution of coal Generation during sample period, excluding Germany and Poland, with vertical box plots capturing the $\pm 1.5 \times \text{IQR}$ (the interquartile range) with bounds at the 25th percentile (Q1) and 75th percentile (Q3). The center line of the box represents the median (50th percentile). Whiskers extend to the smallest and largest values within $1.5 \times \text{IQR}$ of the lower and upper quartiles, respectively, while dots correspond to the outliers outside this range.

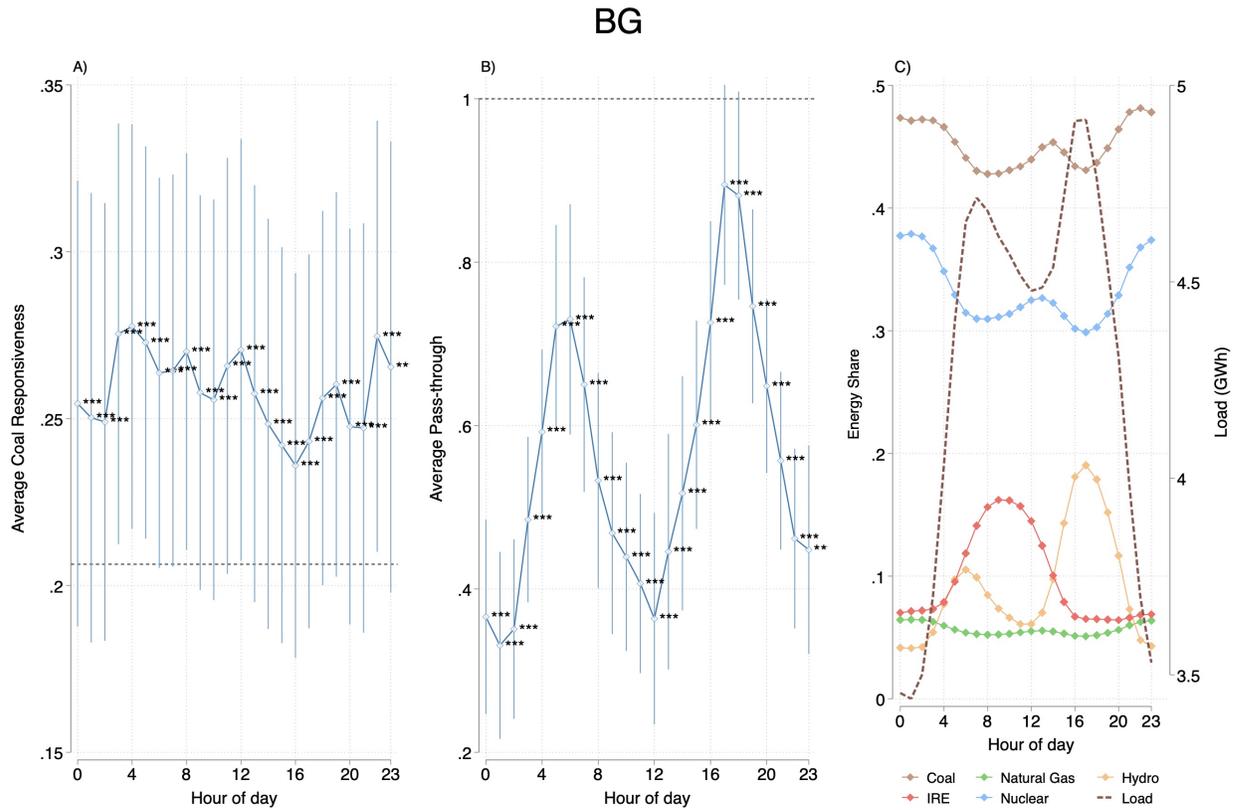
Average Price Ratio Effect on Coal Generation



Supplementary Fig. 18: Estimates of coal responsiveness estimates under main specification during main sample period from April 2021-June 2022.

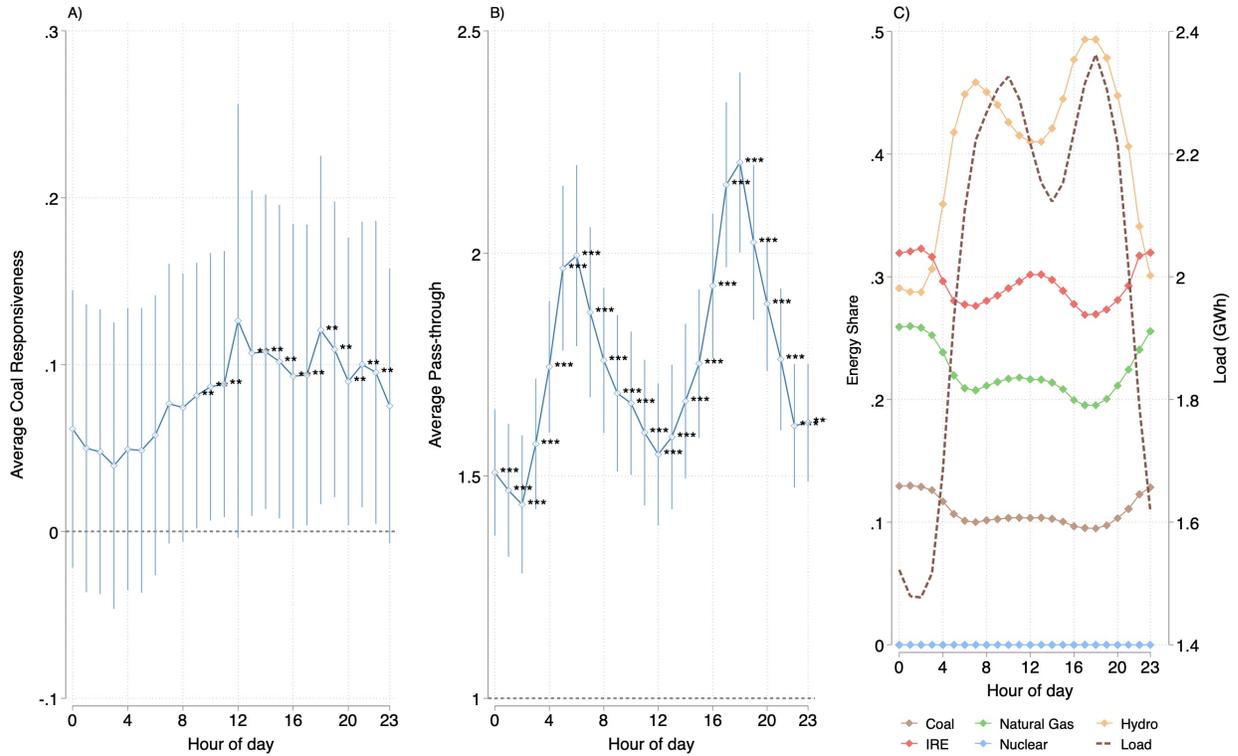


Supplementary Fig. 19: Estimates from pass-through regression across countries of natural gas TTF price to wholesale electricity price during our main sample period from April 2021-June 2022.



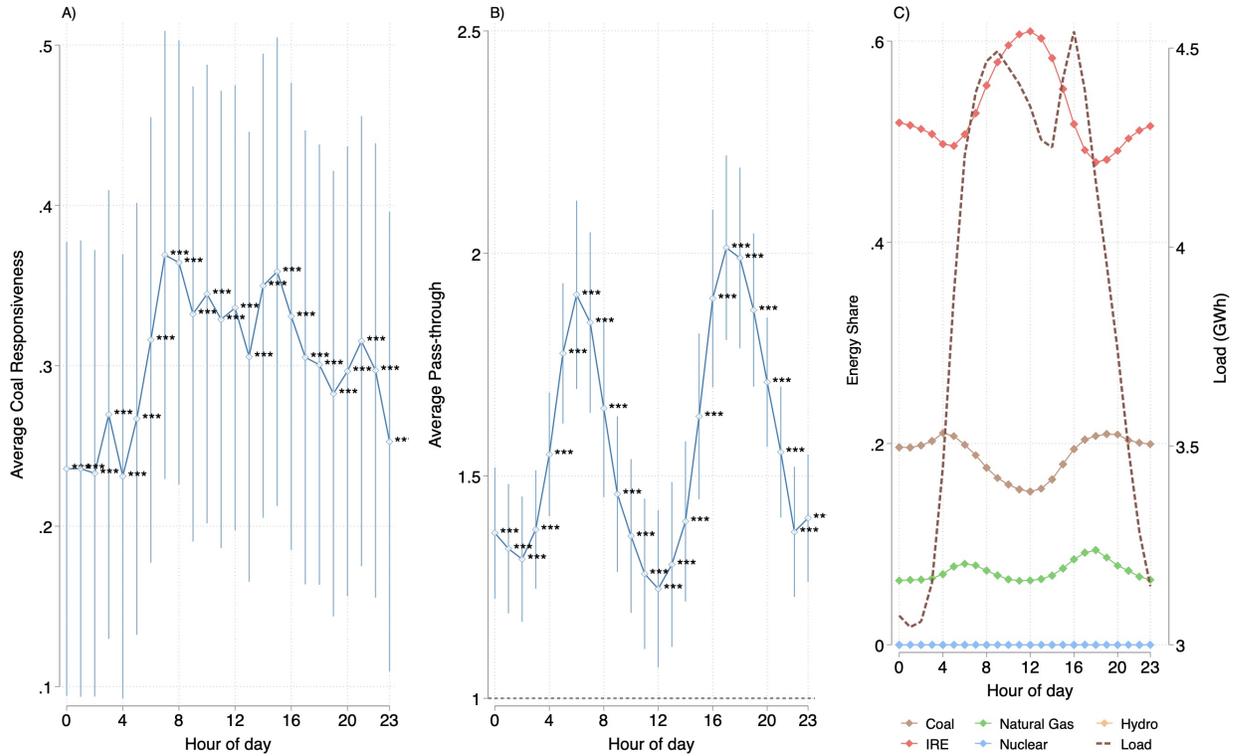
Supplementary Fig. 20: Estimated hourly coal responsiveness coefficients (left panels), estimated pass-through coefficients by hour (middle panels) and the average share of different generation technologies used by hour (right panels) for Bulgaria, using our main specifications for each country (EDF Figure 5 & EDF Table 6) while including an hourly interaction term with our regressor of interest. Dots in the first two panels represent the estimated hourly coal responsiveness or pass-through coefficients respectively, while the vertical lines capture 95% confidence intervals (± 1.96 times the standard error of each point estimate). The statistical test used is a two-sided t-test. The coefficients that are statistically distinct from either 0 or 1 at the 1% or 5% significance level are indicated with three stars or two stars, respectively. In the right panel, “intermittent renewable” includes solar, wind, and hydro-run-of-river. The dashed line displays the average hourly load.

HR



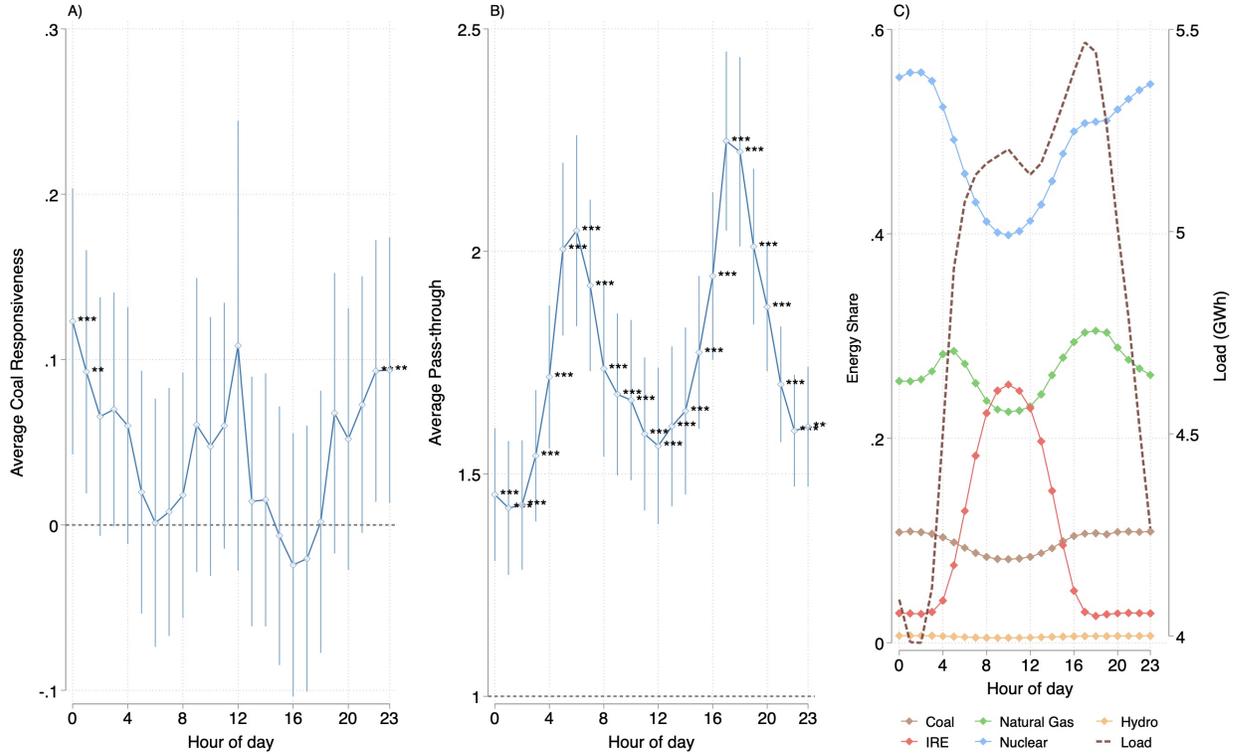
Supplementary Fig. 21: Estimated hourly coal responsiveness coefficients (left panels), estimated pass-through coefficients by hour (middle panels) and the average share of different generation technologies used by hour (right panels) for Croatia, using our main specifications for each country (EDF Figure 5 & EDF Table 6) while including an hourly interaction term with our regressor of interest. Dots in the first two panels represent the estimated hourly coal responsiveness or pass-through coefficients respectively, while the vertical lines capture 95% confidence intervals (± 1.96 times the standard error of each point estimate). The statistical test used is a two-sided t-test. The coefficients that are statistically distinct from either 0 or 1 at the 1% or 5% significance level are indicated with three stars or two stars, respectively. In the right panel, “intermittent renewable” includes solar, wind, and hydro-run-of-river. The dashed line displays the average hourly load.

DK



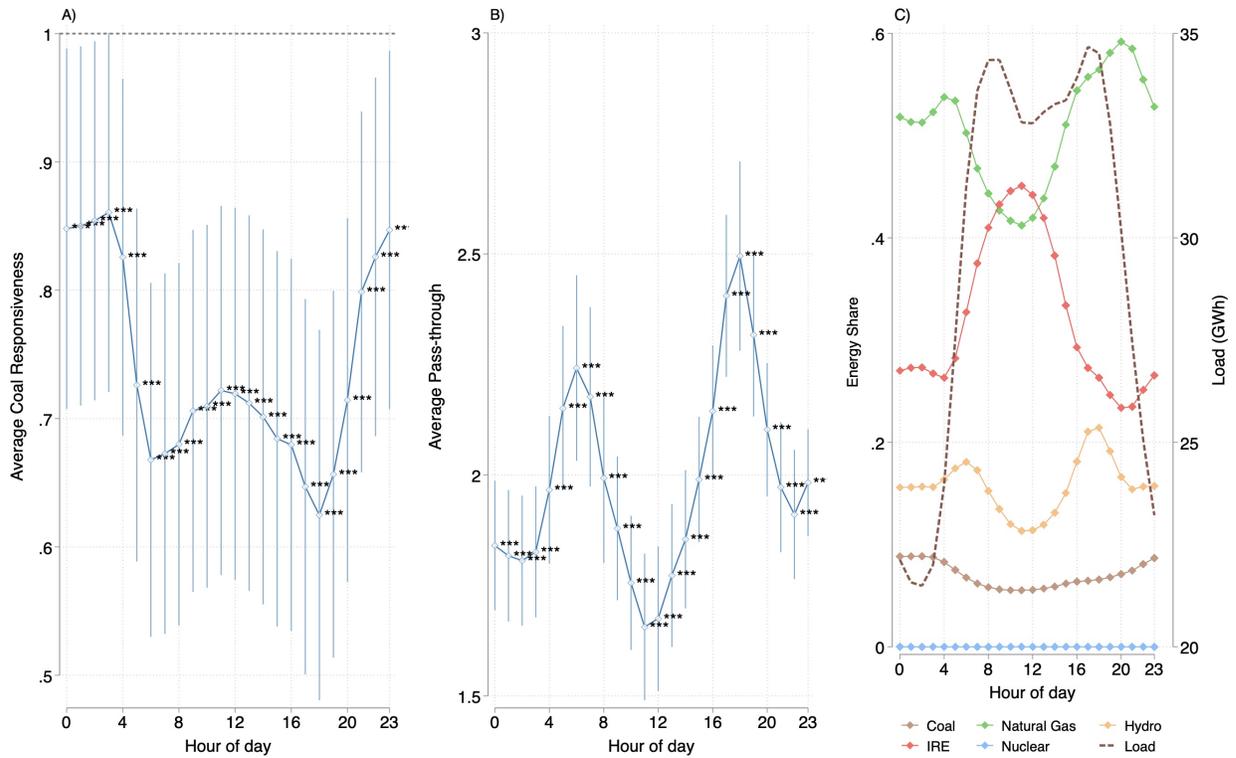
Supplementary Fig. 22: Estimated hourly coal responsiveness coefficients (left panels), estimated pass-through coefficients by hour (middle panels) and the average share of different generation technologies used by hour (right panels) for Denmark, using our main specifications for each country (EDF Figure 5 & EDF Table 6) while including an hourly interaction term with our regressor of interest. Dots in the first two panels represent the estimated hourly coal responsiveness or pass-through coefficients respectively, while the vertical lines capture 95% confidence intervals (± 1.96 times the standard error of each point estimate). The statistical test used is a two-sided t-test. The coefficients that are statistically distinct from either 0 or 1 at the 1% or 5% significance level are indicated with three stars or two stars, respectively. In the right panel, “intermittent renewable” includes solar, wind, and hydro-run-of-river. The dashed line displays the average hourly load.

HU



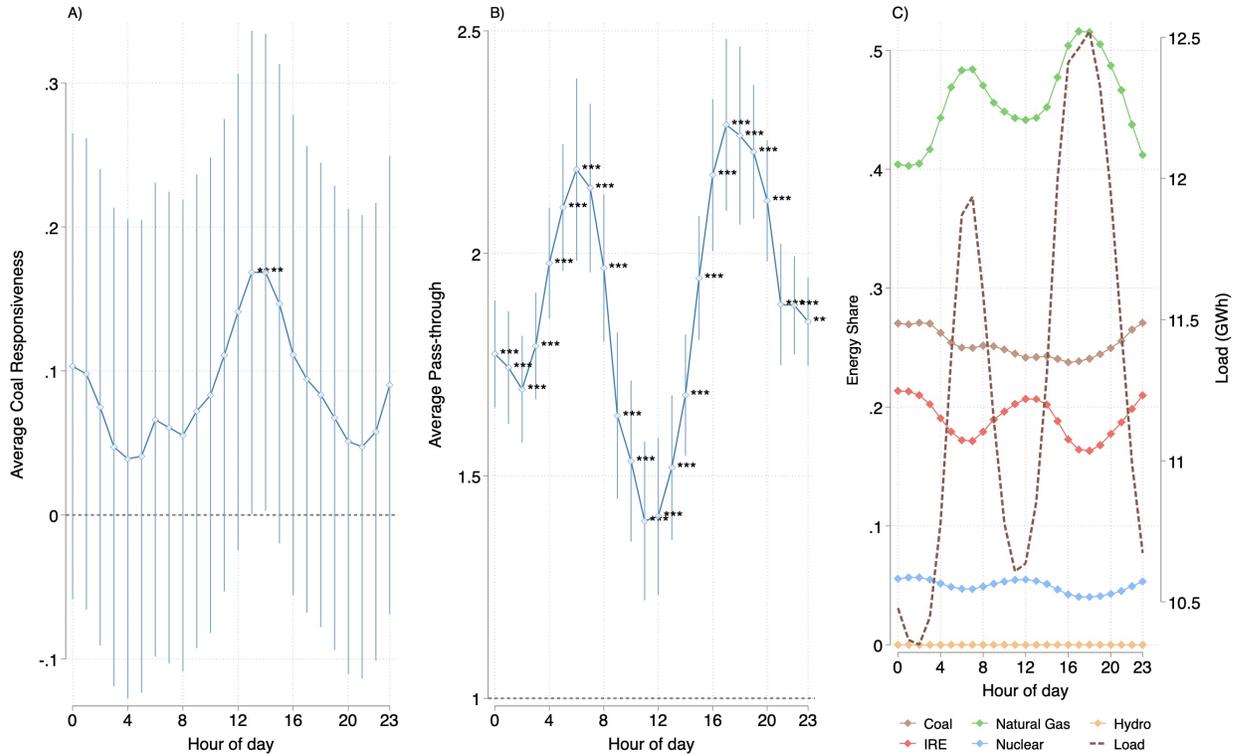
Supplementary Fig. 23: Estimated hourly coal responsiveness coefficients (left panels), estimated pass-through coefficients by hour (middle panels) and the average share of different generation technologies used by hour (right panels) for Hungary, using our main specifications for each country (EDF Figure 5 & EDF Table 6) while including an hourly interaction term with our regressor of interest. Dots in the first two panels represent the estimated hourly coal responsiveness or pass-through coefficients respectively, while the vertical lines capture 95% confidence intervals (± 1.96 times the standard error of each point estimate). The statistical test used is a two-sided t-test. The coefficients that are statistically distinct from either 0 or 1 at the 1% or 5% significance level are indicated with three stars or two stars, respectively. In the right panel, “intermittent renewable” includes solar, wind, and hydro-run-of-river. The dashed line displays the average hourly load.

IT

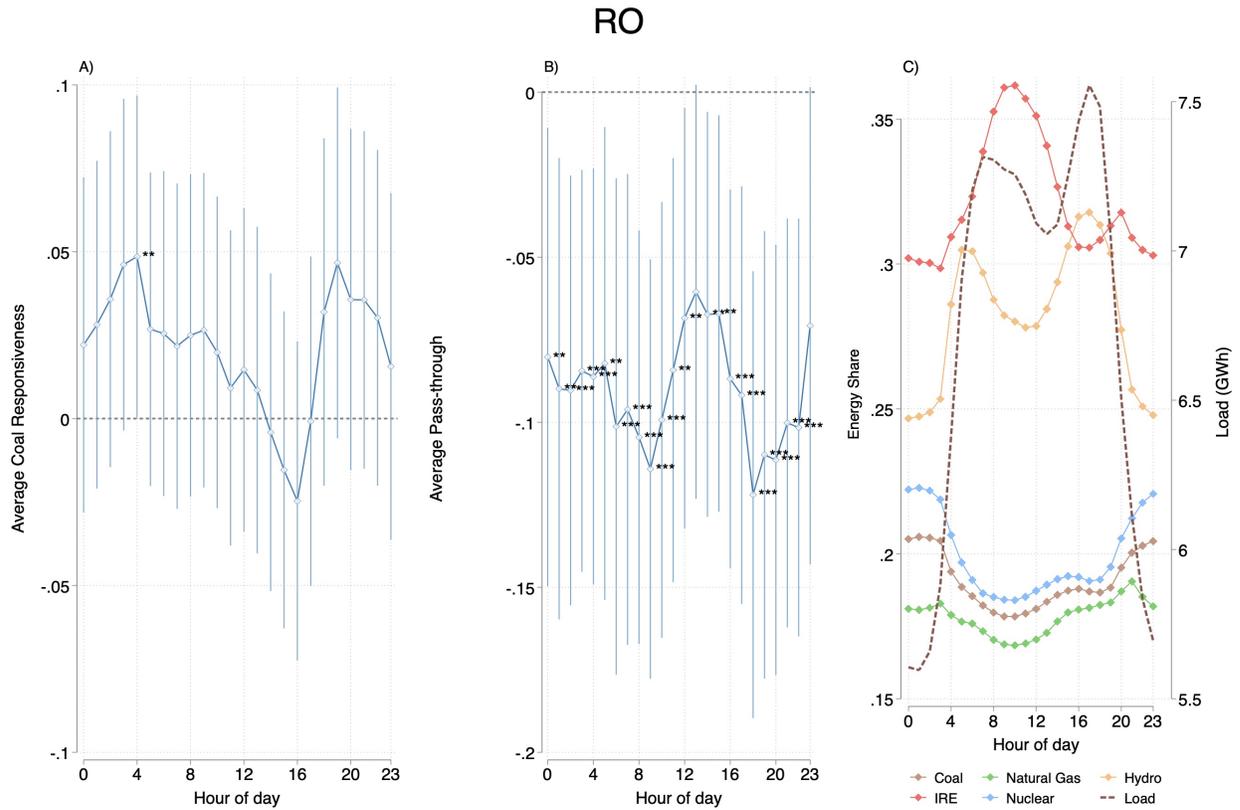


Supplementary Fig. 24: Estimated hourly coal responsiveness coefficients (left panels), estimated pass-through coefficients by hour (middle panels) and the average share of different generation technologies used by hour (right panels) for Italy, using our main specifications for each country (EDF Figure 5 & EDF Table 6) while including an hourly interaction term with our regressor of interest. Dots in the first two panels represent the estimated hourly coal responsiveness or pass-through coefficients respectively, while the vertical lines capture 95% confidence intervals (± 1.96 times the standard error of each point estimate). The statistical test used is a two-sided t-test. The coefficients that are statistically distinct from either 0 or 1 at the 1% or 5% significance level are indicated with three stars or two stars, respectively. In the right panel, “intermittent renewable” includes solar, wind, and hydro-run-of-river. The dashed line displays the average hourly load.

NL



Supplementary Fig. 25: Estimated hourly coal responsiveness coefficients (left panels), estimated pass-through coefficients by hour (middle panels) and the average share of different generation technologies used by hour (right panels) for the Netherlands, using our main specifications for each country (EDF Figure 5 & EDF Table 6) while including an hourly interaction term with our regressor of interest. Dots in the first two panels represent the estimated hourly coal responsiveness or pass-through coefficients respectively, while the vertical lines capture 95% confidence intervals (± 1.96 times the standard error of each point estimate). The statistical test used is a two-sided t-test. The coefficients that are statistically distinct from either 0 or 1 at the 1% or 5% significance level are indicated with three stars or two stars, respectively. In the right panel, “intermittent renewable” includes solar, wind, and hydro-run-of-river. The dashed line displays the average hourly load.



Supplementary Fig. 26: Estimated hourly coal responsiveness coefficients (left panels), estimated pass-through coefficients by hour (middle panels) and the average share of different generation technologies used by hour (right panels) for Romania, using our main specifications for each country (EDF Figure 5 & EDF Table 6) while including an hourly interaction term with our regressor of interest. Dots in the first two panels represent the estimated hourly coal responsiveness or pass-through coefficients respectively, while the vertical lines capture 95% confidence intervals (± 1.96 times the standard error of each point estimate). The statistical test used is a two-sided t-test. The coefficients that are statistically distinct from either 0 or 1 at the 1% or 5% significance level are indicated with three stars or two stars, respectively. In the right panel, “intermittent renewable” includes solar, wind, and hydro-run-of-river. The dashed line displays the average hourly load.