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Who Pays When Generation Fails? Cross-Border Effects of Swedish Nuclear Outages

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Abstract

I estimate the cross-border effects of Swedish nuclear outages using hourly data on day-ahead prices, generation, and consumption across 15 bidding zones in Northern Europe from 2021 to 2024. I exploit unplanned outages as exogenous variation in nuclear supply and find that a 1 GW reduction in Swedish nuclear capacity increases the day-ahead price in the SE-Stockholm bidding zone by approximately 28 percent (17 EUR/MWh). Although less precisely estimated, prices in Finland, Denmark, and the Baltics increase by about 12–13 EUR/MWh. In Norway, contemporaneous price effects are largely offset by increased hydro generation, implying an intertemporal displacement of costs as reservoir levels decline. Since short-run demand is approximately inelastic within the relevant price range, changes in consumer surplus are well approximated by the price change multiplied by the quantity consumed. Abstracting from dynamic effects due to hydro substitution, Swedish consumers bear approximately half of the total short-run loss in consumer surplus, with Finland accounting for the largest share among neighboring countries.

Keywords: nuclear power, electricity markets, cross-border externalities, generation adequacy, market integration, EUPHEMIA
JEL codes: L94, Q48, F15, H25

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1 Introduction

Europe operates one of the world's most integrated international electricity markets. Extensive cross-border transmission capacity and a harmonized day-ahead clearing mechanism link national power systems into a single interconnected market spanning over 50 bidding zones. A well-established body of research documents that this integration generates substantial welfare gains through more efficient dispatch, resource sharing, and enhanced competition (Newbery et al., 2016; Pollitt, 2019). Yet integration also means that disruptions in one country's generation fleet are no longer contained within national borders. When a large power plant fails, the resulting price shock propagates through the interconnected market, imposing costs on consumers in neighboring countries who have no influence over the generation fleet that caused the disruption.

This paper provides empirical evidence on the magnitude of such cross-border externalities from generation outages. I estimate the international price effects of unplanned nuclear outages at Swedish power plants, exploiting approximately 100 individual failure events between 2021 and 2024 as exogenous supply shocks. The analysis covers 15 bidding zones in the Nordic and Baltic regions, using hourly data on day-ahead prices, generation, and consumption.

While the existence of cross-border price transmission in integrated electricity markets is well established in theory, its empirical magnitude for specific generation technologies and market configurations is not. Quantifying this magnitude matters for policy. Generation adequacy has traditionally been conceived as a national responsibility. Each country sets its own adequacy standards, manages its own generation fleet, and procures its own reserves. The European resource adequacy assessment framework, introduced through the Risk-Preparedness Regulation (Regulation (EU) 2019/941), represents a step toward regional coordination, but adequacy assessments and corrective actions remain fundamentally national. Astier and Ovaere (2022) show that national adequacy standards in interconnected systems can only reach the welfare optimum if the calculations fully internalize the external benefits occurring in neighboring systems, a condition that is unlikely to hold in practice. Their numerical application further suggests that the cross-border adequacy benefits of European interconnections are economically significant. Joskow and Tirole (2007) demonstrate that competitive electricity markets generally require regulatory intervention to ensure efficient provision of generation adequacy, though their analysis focuses on a single-market setting. The present paper complements these theoretical contributions by documenting the cost dimension of cross-border adequacy dependence: it quantifies how supply disruptions in one country translate into consumer costs across the interconnected market, even when the system is not under severe stress.

The degree of market integration is likely to increase further. The European Commission's Grids Package, adopted in December 2025, targets a doubling of cross-border transmission capacity by 2030, alongside accelerated permitting and regulatory incentives for grid investment (European Commission, 2025a). As interconnection capacity expands, the share of outage costs borne by foreign consumers will grow, making the coordination problem documented in this paper increasingly salient.

Sweden provides a particularly useful empirical setting. Sweden's six nuclear reactors, all located in the SE-Stockholm bidding zone, provide approximately 30 percent of national electricity generation and constitute a substantial share of firm capacity in the Nordic system. The SE-Stockholm zone is well connected to neighboring countries through both AC and DC interconnectors, with Finnish and SE-Stockholm prices being identical in roughly 62 percent of all hours. Nuclear reactors operate as baseload and are either running at full capacity or offline, which means that unplanned outages generate discrete, clearly identifiable supply shocks. Since unplanned outages arise from equipment failures and safety system trips, they are plausibly exogenous to contemporaneous market conditions. I confirm this by showing that unplanned outages are uncorrelated with temperature, wind, and solar conditions, in contrast to planned maintenance which is systematically scheduled during periods of low demand.

I find that a 1 GW reduction in Swedish nuclear capacity raises the day-ahead price in SE-Stockholm by about 28 percent (17 EUR/MWh). Although somewhat less precisely estimated, prices in Finland, Denmark, and the Baltic states increase by roughly 12–13 EUR/MWh. In Norway, contemporaneous price effects are largely offset by increased hydro generation, though these estimates are less precisely estimated than for the other countries. In specifications restricted to hours with a high probability of market integration, as indicated by price equalization across zones, cross-border price effects are even larger. Estimates that allow the price effect to vary over the first ten days of an outage show no statistically distinguishable difference across days. Placebo tests that shift outages one week forward or backward in time yield consistently economically small and statistically insignificant effects.

Short-run electricity demand is approximately inelastic over the relevant price ranges. Consequently, changes in consumer surplus are well approximated by the price change multiplied by consumption. Abstracting from dynamic effects associated with hydro reservoir depletion, I estimate that Swedish consumers bear roughly half of the total short-run loss in consumer surplus from nuclear outages, with most of the remaining burden falling on consumers in neighboring countries, particularly Finland. Nuclear outages also generate productive inefficiency, as low-cost nuclear generation must be replaced by more expensive alternatives, and redistribute surplus toward infra-marginal producers. Estimating these additional welfare components is beyond the scope of the paper; Section 5.4 discusses them in more detail.

I further examine supply responses using the same identification strategy. The dominant adjustment margin is increased hydro generation in Norway and, to a lesser extent, Sweden. While this response stabilizes prices in the short run, it reduces reservoir levels and is likely to raise prices in subsequent periods. The short-run price estimates therefore understate Norway's total exposure to Swedish nuclear outages and, more generally, the foreign share of the total loss in consumer surplus.

Germany and Poland are excluded from the analysis. Although geographically proximate, these markets are less tightly integrated with SE-Stockholm than the Nordic and Baltic zones, and their large trading volumes make it empirically difficult to identify precise effects of Swedish nuclear availability. To the extent that Swedish outages do affect German and Polish prices, excluding these markets implies that the estimated cross-border effects also understates the foreign share. More generally, several additional factors omitted from the analysis all bias in the same direction: intertemporal costs of Norwegian hydro reservoir depletion; increased cross-border capacity under flow-based market coupling introduced after the sample period; and Sweden's below-proportional share of Nordic balancing market procurement. These factors are discussed in detail in Sections 2 and 5. The finding that roughly half of the costs fall outside Sweden is therefore likely conservative.

The study connects to several literatures. Recent studies on short-term cross-border effects within the EU electricity market have focused on renewable output. See De Blauwe et al. (2025) for the first meta-study, examining about 50 empirical studies, and Stiewe et al. (2025); Sikorska-Pastuszka and Papiez (2023) for recent examinations of cross-country dependencies in renewable output and prices. The present paper adds to this literature by estimating cross-border effects from nuclear generation, where thermal output is endogenous to market conditions and unplanned outages provide a source of exogenous variation. Methodologically, the most closely related paper is Rinne (2019), who examines spillovers from French nuclear outages to the German market during a single episode from October 2016 to February 2017, when safety concerns led to the shutdown of 12 reactors representing approximately 20 percent of French nuclear capacity. Rinne employs a quasi-experimental matching approach that compares this five-month treatment period to matched control periods, finding that the capacity shock increased French spot prices by approximately 14 EUR/MWh and German prices by approximately 2 EUR/MWh. The present paper builds on this approach by exploiting approximately 100 individual unplanned outage events occurring over four years, using a regression framework with continuous variation in unavailable capacity, and extending the analysis to a larger set of interconnected countries.

The paper also connects to an empirical literature on the market effects of permanent or long-term nuclear capacity reductions. Davis and Hausman (2016) analyze the closure of the San Onofre Nuclear Generating Station in California and document large increases in generation costs driven by natural gas substitution and binding transmission constraints. Jarvis et al. (2022) study the German nuclear phase-out following Fukushima and show that lost nuclear production was replaced by coal-fired generation and electricity imports, generating substantial social costs through increased air pollution. Using simulation methods, Bianco and Scarpa (2018) examine the potential impact of French nuclear phase-out on Italian wholesale prices and find significant cross-border effects through changed import patterns. While these studies provide valuable evidence on the consequences of nuclear closures, they either focus on domestic effects or rely on simulation rather than reduced-form estimation. The present paper complements this work by providing reduced-form estimates of short-run cross-border effects.

Even though the analysis focuses on short-run effects, there is no clear reason to expect long-run incidence to differ qualitatively in terms of the aggregate foreign share. Modeling long-run responses requires strong assumptions about long-run cross-country differences in demand and supply elasticities that are difficult to validate empirically. The reduced-form estimates in this paper therefore provide a useful complement to long-run simulation models such as Hirth (2024) when assessing cross-border effects of nuclear policy. Indeed, several European governments have recently introduced or received approval for state aid schemes aimed at financing new nuclear capacity or extending the operation of existing plants, including Sweden, France, Poland, the Czech Republic, and Belgium (Swedish Government, 2025; French Government, 2025; European Commission, 2024, 2025b,c). If the benefits of such investments spill across borders through integrated wholesale markets, national cost-benefit analyses may systematically understate the regional return. Bagwell and Staiger (2002) develop the foundational theoretical framework showing that domestic policies create cross-border externalities via their effects on international prices. Hoekman and Nelson (2020) build on this framework to argue that subsidy policies inevitably generate spillover effects requiring cooperative solutions. In the present context, this logic suggests that coordination of nuclear investment subsidies across countries could improve regional welfare relative to unilateral national schemes.

The remainder of the paper proceeds as follows. Section 2 describes the institutional setting, including the Nordic electricity market and the EUPHEMIA clearing mechanism. Section 3 presents the data sources, focusing on the UMM platform for outage information. Section 4 develops the econometric framework and discusses identification. Section 5 presents the main results, and Section 6 concludes.

2 The European electricity wholesale market

2.1 The EUPHEMIA algorithm and day-ahead market clearing

Electricity in Europe is traded through a sequence of markets that differ in their timing relative to physical delivery. The day-ahead market, which is the focus of this study, clears the day before delivery. To complement for this lag, intraday markets allow participants to adjust positions closer to real-time. Balancing markets, operated by transmission system operators, resolve any remaining imbalances between supply and demand in real-time. While all three market segments respond to supply shocks such as nuclear outages, the day-ahead market accounts for the vast majority of traded volume and serves as the primary reference for wholesale electricity prices across Europe.

In theory, it would also be possible to consider the effects on the balancing market, where transmission system operators procure frequency containment reserves (FCR) to maintain system stability in real time. The Nordic balancing market covers the same synchronous area as the day-ahead market but does not yet include the Baltic countries. The Nordic TSOs jointly determine the total required procurement volume, which is then allocated to individual countries based on annual consumption and production. For 2026, Sweden's allocation share is 38 percent (Svenska Kraftnät, 2025), which is lower than the estimated Swedish share of day-ahead consumer surplus losses at 42-53 percent. This suggests that incorporating balancing market effects would, if anything, reduce the Swedish share of total consumer surplus losses further. Moreover, while the precise consumer cost of individual outages in the balancing market is difficult to quantify, it is likely to be substantially smaller than the cost transmitted through the day-ahead market.

Since 2014, day-ahead electricity prices across most of Europe have been determined through a single coordinated auction known as Single Day-ahead Coupling (SDAC). The auction is cleared by the EUPHEMIA algorithm (Pan-European Hybrid Electricity Market Integration Algorithm), which simultaneously determines prices and quantities for all participating bidding zones while respecting transmission constraints between them.

The timeline proceeds as follows. Market participants submit bids to their respective power exchanges by 12:00 Central European Time for delivery during each hour of the following day. These bids specify quantities and prices at which participants are willing to buy or sell electricity. Generators typically submit supply curves indicating the minimum price at which they will produce various quantities, while consumers and retailers submit demand curves indicating the maximum price they are willing to pay. The bidding window closes at noon, and EUPHEMIA computes results within approximately one hour, with prices published around 13:00 CET.

EUPHEMIA solves a welfare maximization problem: it seeks to maximize the total gains from trade across all participating zones, subject to the constraint that cross-border flows cannot exceed available transmission capacity. When transmission capacity is sufficient to accommodate all beneficial trades, the algorithm produces a uniform price across connected zones. When transmission lines are congested, prices diverge to reflect local scarcity conditions. A zone with excess demand relative to available supply and import capacity will clear at a higher price than a zone with abundant supply.

The algorithm handles considerable complexity. As of 2024, EUPHEMIA clears markets for 27 countries comprising more than 50 bidding zones, processing millions of bids to determine prices for each of the 24 hours of the following day. The optimization accounts for various bid types including simple hourly bids, block bids that span multiple hours, and complex bids with technical constraints reflecting the physical characteristics of power plants.

2.2 Bidding zones and transmission constraints

A bidding zone is a geographic area within which a single price applies. Zone boundaries typically follow national borders, but several countries are divided into multiple zones to reflect internal transmission constraints. Sweden, which is central to this study, is divided into four bidding zones running from north to south: SE-Luleå; SE-Sundsvall; SE-Stockholm, and SE-Malmö. Norway is divided into five zones, while Denmark has two. Germany and Luxembourg form a single zone despite being separate countries, as do Austria and Germany until their separation in 2018.

The rationale for multiple zones within a country is that internal transmission capacity may be insufficient to ensure price convergence. Northern Sweden, for instance, has abundant hydropower production but limited transmission capacity to the population centers in the south. Without zonal separation, the uniform national price would fail to signal the true scarcity in southern regions or the abundance in northern ones, potentially leading to inefficient dispatch and investment decisions.

When EUPHEMIA determines that a transmission line between two zones is congested, it sets prices in each zone to clear local supply and demand given the constrained flow. The price difference between zones, multiplied by the flow, generates congestion revenue that accrues to transmission system operators. These revenues can be substantial during periods of high demand or low renewable output, and their allocation across countries is governed by regulatory agreements.

2.3 The Nordic electricity market

The Nordic countries were pioneers in electricity market liberalization and cross-border integration. Nord Pool, established in 1996, was the world's first multinational power exchange. Today, Nordic day-ahead trading occurs through the SDAC framework, but the region retains distinctive features reflecting its generation mix and historical development.

Hydropower dominates the Nordic system, accounting for approximately half of total generation in a typical year. Norway derives over 90 percent of its electricity from hydropower, while Sweden obtains roughly 40 percent from hydro and 30 percent from nuclear. Finland has a more diverse mix including nuclear, combined heat and power, and increasingly wind. Denmark relies heavily on wind power, with thermal backup.

The prevalence of hydropower creates important intertemporal linkages. Unlike thermal generators, which incur fuel costs when operating, hydropower plants face an opportunity cost: water released today is unavailable for future periods. Hydro producers therefore optimize not only across hours within a day but across weeks, months, and even years, depending on reservoir capacity. This dynamic optimization means that short-run supply shocks, such as nuclear outages, may be partially absorbed by increased hydro generation, but at the cost of depleting reservoirs and potentially raising prices in future periods.

Sweden's position within the Nordic system is particularly relevant for this study. Swedish nuclear plants, all located in SE-Stockholm, provide baseload generation that flows both northward to the hydro-rich regions and southward toward Denmark and the continent. When nuclear output falls unexpectedly, prices in SE-Stockholm rise directly. The effect transmits to neighboring zones depending on transmission capacity and local supply conditions: northern Swedish zones with hydro reserves may increase output, while southern zones and Finland may see price increases reflecting reduced import availability.

Finland is connected to Sweden through both AC lines and DC interconnectors, with substantial transmission capacity enabling close price integration. In the data I analyze, Finnish and SE-Stockholm prices are identical in approximately 62 percent of all hours. Norway connects to Sweden primarily through the southern and central zones, with price correlation varying by Norwegian region. The Baltic states connect to the Nordic system through Estonia's link to

Finland (Estlink) and Lithuania's link to Sweden (NordBalt), providing pathways through which Swedish nuclear outages can affect prices in Latvia, Lithuania, and Estonia.

2.4 Balancing markets and real-time adjustments

The day-ahead market clears based on forecasts of supply and demand for the following day. Actual conditions inevitably deviate from these forecasts: wind output may differ from predictions, demand may respond to unexpected weather, and generation units may experience unplanned outages. Balancing markets exist to manage these deviations in real-time.

When a nuclear reactor trips unexpectedly, the immediate physical response involves balancing markets. The transmission system operator activates reserves, typically fast-responding hydropower or thermal units, to maintain system frequency and prevent outages. Generators providing these services receive balancing market prices, which can spike dramatically during scarcity events. The costs of balancing are ultimately allocated to market participants through imbalance settlement mechanisms.

However, if the outage is expected to persist, market participants adjust their positions in subsequent day-ahead auctions. A reactor that trips on Monday afternoon affects balancing markets on Monday evening and Tuesday. But for Wednesday and beyond, the reduced nuclear availability is incorporated into day-ahead bids, with competing generators offering to fill the gap and consumers adjusting their demand in response to anticipated higher prices. The day-ahead market thus captures the medium-term price response to supply shocks, while balancing markets capture the immediate real-time response.

This study focuses on day-ahead prices for several reasons. First, the day-ahead market is the most liquid and transparent market segment, with publicly available price data at hourly resolution for all bidding zones. Second, day-ahead prices serve as the reference for most wholesale contracts, including the contracts for difference that underpin nuclear investment support schemes. Third, the welfare calculations I perform, based on consumer surplus changes from price movements, are most straightforward to interpret for the day-ahead market where quantities are determined by voluntary trades rather than emergency dispatch.

The focus on day-ahead prices likely understates the total price effect of nuclear outages. Balancing market prices during outage events can exceed day-ahead prices substantially, imposing additional costs on consumers and windfall gains on generators with available capacity. A complete welfare accounting would incorporate these effects, but the data requirements and methodological complexity are beyond the scope of this paper.

It is worth emphasizing what this study aims to measure and what it does not. The objective is not to compute the complete price or welfare effect of a nuclear outage in absolute terms. Such an exercise would require accounting for balancing market responses, intertemporal hydro optimization, generator profits, congestion revenues, and numerous other factors that are difficult to quantify with available data. Rather, the aim is to estimate the relative distribution of price effects across countries. Even if the absolute magnitudes are measured with error or represent only a portion of the total effect, the relative distribution across countries remains informative for policy, provided there is no reason to expect the measurement error to differ systematically across borders.

2.5 Nuclear power in Sweden

Sweden currently operates six nuclear reactors at three sites: Forsmark (units 1, 2, and 3), Ringhals (units 3 and 4), and Oskarshamn (unit 3). All are located in SE-Stockholm and together provide approximately 30 percent of Sweden's electricity generation (International Energy Agency, 2024). The fleet expanded rapidly in the 1970s and 1980s, peaking at twelve reactors, but a series of closures reduced capacity to the current six units with a combined capacity of approximately 7 GW.

Ownership is characterized by cross-holdings among major utilities. Vattenfall, the state-owned utility, holds majority stakes in both Forsmark (66 percent) and Ringhals (70 percent), while Uniper and Fortum hold minority positions. Lundin (2021) finds evidence that this joint ownership structure leads to coordinated maintenance scheduling consistent with joint profit maximization. The study also demonstrates that while the timing of planned maintenance is consistent with strategic behavior, unplanned outages are not.

Following the 2022 election, the Swedish government adopted an explicitly pro-nuclear stance, targeting new capacity equivalent to at least two large-scale reactors by 2035. In May 2025, parliament approved a state aid framework providing government loans and contracts for difference for new nuclear construction (Swedish Government, 2025). Vattenfall is currently evaluating both large-scale reactors and small modular reactors for deployment at existing sites (Vattenfall AB, 2025). The existing fleet is thus likely to remain the core of Swedish nuclear generation for at least another decade, making the present analysis of cross-border price effects directly relevant for assessing future investment decisions.

3 Descriptive statistics

3.1 Nuclear output and outages

Hourly production data for Swedish nuclear plants are collected from Svenska Kraftnät, the Swedish transmission system operator. These data are also available through the ENTSO-E Transparency Platform, though the ENTSO-E records are incomplete for the Swedish plants.

Information on outages comes from Urgent Market Messages (UMMs) published on the ENTSO-E Transparency Platform. Data from this database have previously been used to assess the strategic behavior of nuclear plant owners by Lundin (2021). The UMM system operates under the EU's Regulation on Energy Market Integrity and Transparency (REMIT), which requires electricity producers to disclose information about planned and unplanned unavailability of generation facilities. Market participants must publish messages as soon as any new information regarding an outage becomes available. One of the primary functions of the UMM system is to prevent insider trading: by mandating prompt disclosure of production disruptions, all market participants have access to the same information when making trading decisions.

Table 1: Unplanned outage events by plant, 2021–2024

	Mean	Min	Max	SD
Oskarshamn (N=22)				
Duration	5.80	0.00	57.25	12.21
GW unavailable	0.67	0.00	1.40	0.56
Messages per event	3.91	1.00	11.00	2.31
Ringhals (N=36)				
Duration	7.19	0.08	54.92	11.69
GW unavailable	0.65	0.01	1.13	0.29
Messages per event	3.92	1.00	13.00	2.56
Forsmark (N=37)				
Duration	6.66	0.00	55.04	12.78
GW unavailable	0.72	0.00	1.17	0.38
Messages per event	5.11	1.00	20.00	3.86

Note: Statistics for 95 unplanned outage events as classified in UMM messages. Duration is measured in days from the first message (event start) to the final message (return to operation). Some failures require extended repair periods, resulting in maximum durations of nearly 60 days.

Each UMM must be classified as either "Planned" or "Unplanned" unavailability. Planned unavailability corresponds to scheduled maintenance, while unplanned unavailability indicates failures. I focus on the unplanned events, which provide exogenous variation in nuclear output. An example of a UMM for an unplanned outage is shown in Appendix Figure A2. The message contains information about the affected production unit, the type and reason for the unavailability, the start and expected end times, and the amount of capacity that is unavailable.

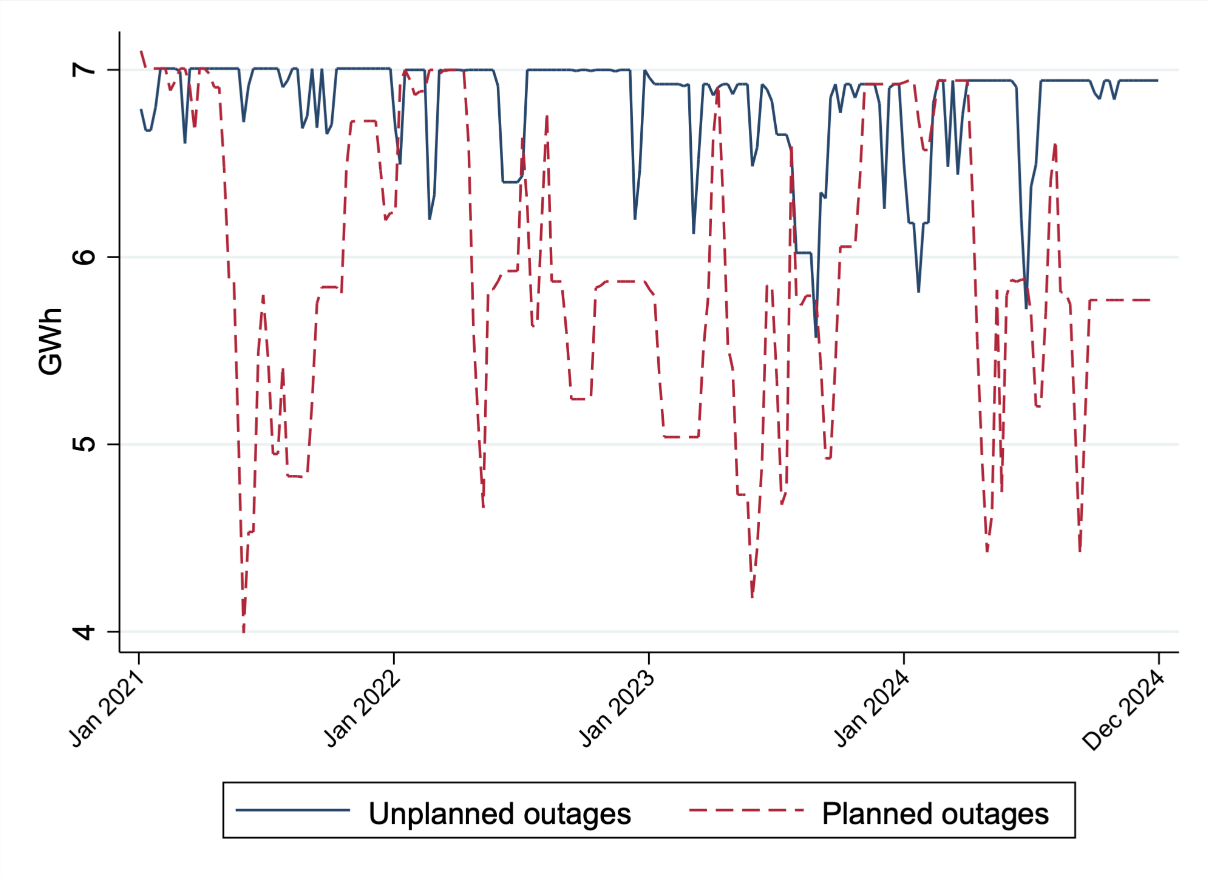
Table 1 presents descriptive statistics for unplanned outage events at the three Swedish nuclear plants during 2021–2024. Events that were resolved before the day-ahead market clearing have been removed from the sample. Forsmark experienced the most events (37), followed by Ringhals (36) and Oskarshamn (22). The average duration of an outage is approximately 6.5 days, though there is substantial variation: some events are resolved within hours, while others take nearly two months to repair. The mean unavailable capacity per event is just below 0.7 GW. This is notably less than the typical reactor capacity of around 1 GW, reflecting the fact that most Swedish reactors are equipped with two turbines of approximately 0.5 GW each, and failures often affect only one turbine.

Each outage event typically generates multiple UMM messages. The first message announces the event and contains accurate information about when the outage began. Subsequent messages provide updated estimates of when the reactor is expected to return to operation, while the final message confirms when the unit is back online. On average, events generate about 4 messages.

Since Swedish nuclear reactors operate as baseload and rarely ramp up or down for economic reasons, they are typically either running at full capacity or offline for maintenance or repairs. This operational pattern means that, in principle, it should be possible to reconstruct the output trajectory of each plant using only the information contained in UMM messages. To obtain the size and starting hour of an event, I use information from the first message associated with that event. Analogously, I use information in the last message to obtain the end hour. For each hour, I then subtract this capacity from the total capacity of the plant.

Figure 1 shows weekly averages of capacity available net of unplanned outages and capacity available net of planned maintenance. The figure reveals that planned maintenance is concentrated in the summer months, when electricity demand is low, while unplanned failures are distributed fairly evenly throughout the year. As a complement, Figure A1 depicts weekly individual plant level output.

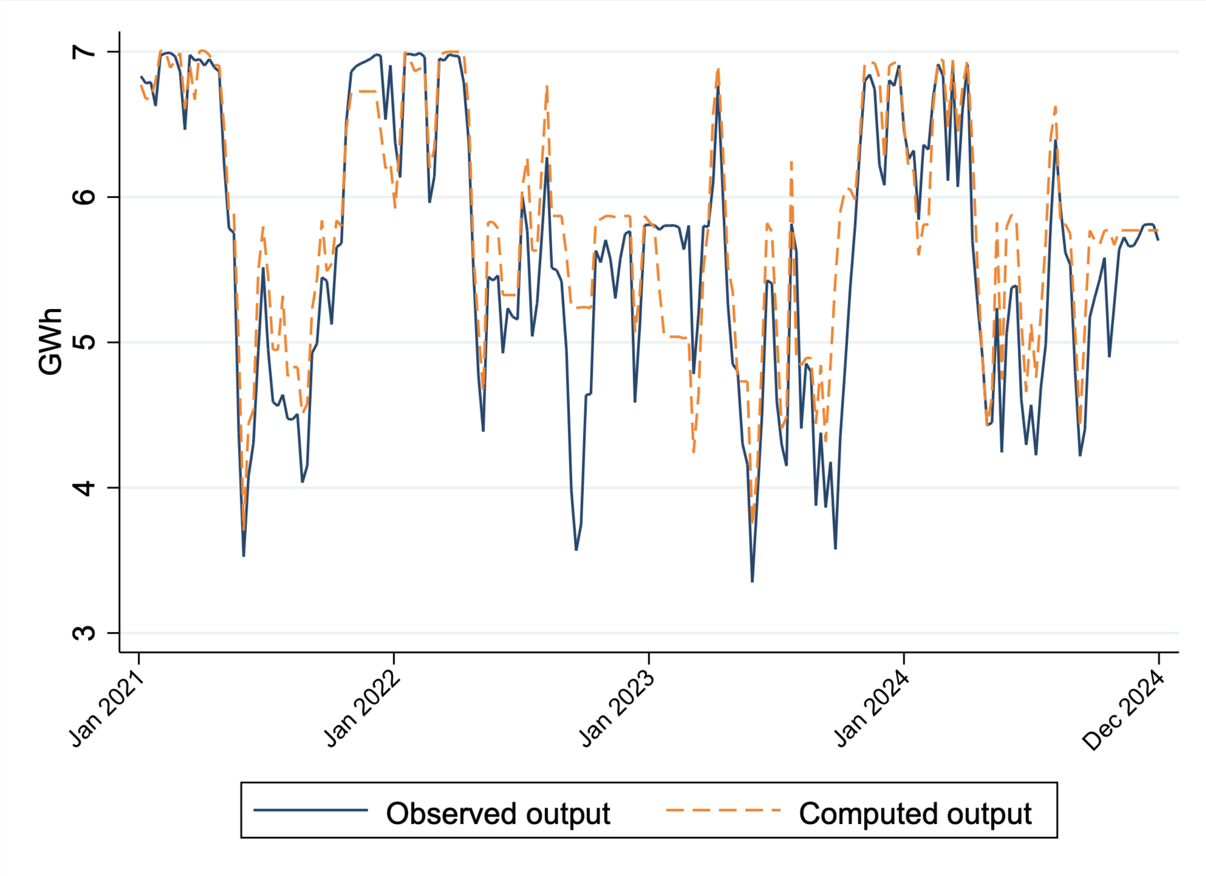
Figure 1: Capacity available net of outages and maintenance



Note: Weekly averages. The solid line shows capacity available net of unplanned outages. The dashed line shows capacity available net of planned maintenance.

Figure 2 compares observed nuclear output with output computed from the UMM messages. To construct the computed series, I use the start time from the first message associated with each event and the end time from the final message. The close correspondence between the observed and computed series validates that the UMM data accurately capture the timing and magnitude of outages. The total installed capacity of the Swedish nuclear fleet is approximately 7 GW, distributed across six operating reactors at three plants: Forsmark (units 1, 2, and 3), Ringhals (units 3 and 4), and Oskarshamn (unit 3).

Figure 2: Observed output and computed output from UMM messages



Note: Weekly averages. Observed output is actual generation. Computed output is maximum capacity minus unavailable capacity as reported in UMM messages.

3.2 Prices

Table 2 presents descriptive statistics on day-ahead electricity prices across the 15 bidding zones in the sample during 2021–2024. Figure 3 displays the geographic distribution of mean prices.

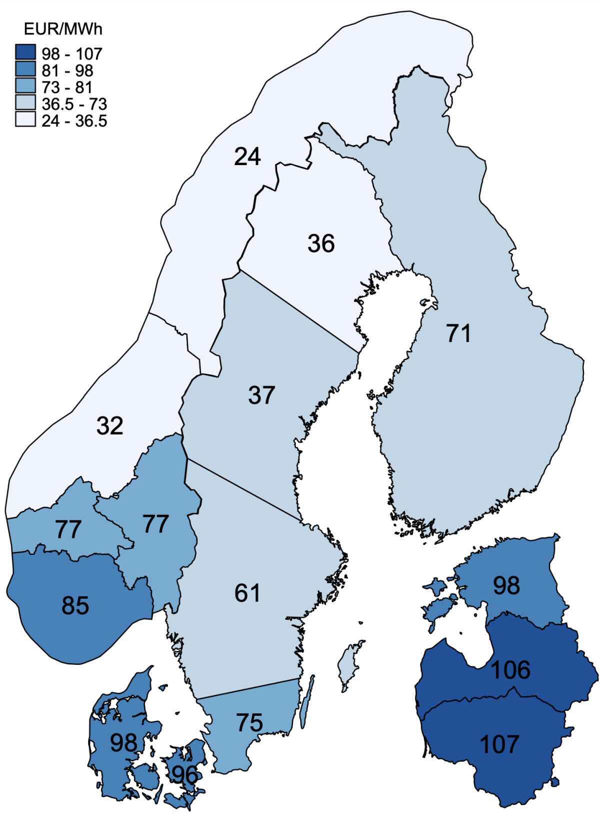
Table 2: Prices by bidding zone, 2021–2024

	Same	Corr	Lower	Higher	Mean	SD
SE-Stockholm	1.00	1.00	0.00	0.00	60.7	78.6
SE-Malmö	0.68	0.91	0.01	0.31	74.6	87.6
SE-Sundsvall	0.62	0.65	0.37	0.01	36.7	46.0
Finland	0.62	0.84	0.08	0.30	71.2	90.2
SE-Luleå	0.61	0.63	0.38	0.01	36.2	45.2
DK-Zealand	0.38	0.78	0.02	0.60	95.7	101.3
NO-Trondheim	0.37	0.57	0.53	0.10	31.8	39.4
Estonia	0.33	0.74	0.01	0.66	98.2	96.5
NO-Oslo	0.32	0.78	0.24	0.44	77.0	85.7
NO-Bergen	0.29	0.77	0.26	0.45	76.7	85.0
Latvia	0.29	0.72	0.01	0.70	106.2	106.9
NO-Tromsø	0.29	0.45	0.63	0.08	24.3	27.8
Lithuania	0.28	0.72	0.00	0.72	107.2	108.4
DK-Jutland	0.24	0.76	0.10	0.65	97.9	101.5
NO-Kristiansand	0.24	0.75	0.23	0.53	85.0	93.4

Note: Day-ahead prices in EUR/MWh. “Same” is the share of hours when the price equals the price in SE-Stockholm. “Corr” is the correlation with SE-Stockholm prices. “Lower” and “Higher” are the shares of hours with prices below and above SE-Stockholm, respectively. Zones are sorted by the “Same” column in descending order.

Average prices vary substantially across bidding zones. The lowest prices are found in northern Scandinavia, where NO-Tromsø averages 24 EUR/MWh and the northern Swedish zones SE-Luleå and SE-Sundsvall average 36–37 EUR/MWh. These areas benefit from abundant hydropower resources and relatively low local consumption. Prices increase moving southward and eastward: SE-Stockholm averages 61 EUR/MWh, Finland 71 EUR/MWh, and the southern Norwegian zones around 77–85 EUR/MWh. The highest average prices are in the Baltic states (98–107 EUR/MWh) and Denmark (96–98 EUR/MWh).

Figure 3: Mean electricity prices by bidding zone



Note: Average day-ahead prices in EUR/MWh during 2021–2024. Darker shading indicates higher prices.

The first column of Table 2, labeled "Same," reports the share of hours in which each zone has an identical price to SE-Stockholm. When two zones clear at the same price, it indicates that transmission constraints between them are not binding during that hour and the EUPHEMIA algorithm treats them as part of an integrated market. This share provides a simple diagnostic of how closely interconnected each zone is with the Stockholm area, where the Swedish nuclear plants are located.

The Swedish zones show the highest degree of price convergence with SE-Stockholm. SE-Malmö in southern Sweden has the same price as SE-Stockholm in 68 percent of hours, while the northern zones SE-Sundsvall and SE-Luleå converge in 61–62 percent of hours. Finland, connected to Sweden via both AC and DC interconnectors, also shows substantial integration at 62 percent. The "Lower" and "Higher" columns reveal asymmetries in price differences when zones diverge: the northern Swedish zones have lower prices than SE-Stockholm in 37–38 percent of hours but higher prices in only 1 percent, indicating that when transmission is congested, these zones are typically exporting power southward toward the consumption centers.

Price convergence declines with distance and across national borders. The Norwegian zones range from 24 to 37 percent, the Danish zones from 24 to 38 percent, and the Baltic states from 28 to 33 percent.

Control variables

Table 3 reports descriptive statistics for the control variables used in the analysis: day-ahead forecasts of wind and solar output, and daily temperatures. Wind and solar forecasts are obtained from the ENTSO-E Transparency Platform and represent the predictions available to market participants when submitting bids to the day-ahead auction. Temperature data are from E-OBS, using measurements at the geographic centroid of each bidding zone.[1]

Table 3: Control variables by bidding area

	Wind		Solar		Temperature	
	Mean	SD	Mean	SD	Mean	SD
DK-Jutland	1.5	1.0	0.2	0.3	8.7	5.9
DK-Zealand	0.4	0.4	0.1	0.1	9.5	6.3
Estonia	0.1	0.1	0.0	0.1	7.2	8.8
Finland	3.3	4.7	0.2	0.4	3.5	10.1
Latvia	0.0	0.0	0.0	0.0	8.0	8.5
Lithuania	0.3	0.5	0.1	0.1	8.4	8.4
NO-Bergen	0.0	0.0	0.0	0.0	1.2	6.9
NO-Kristiansand	0.5	0.4	0.0	0.0	1.9	7.3
NO-Oslo	0.1	0.1	0.0	0.0	5.3	8.6
NO-Tromsø	0.3	0.2	0.0	0.0	-1.8	8.8
NO-Trondheim	0.6	0.5	0.0	0.0	5.0	7.1
SE-Luleå	0.6	0.5	0.0	0.0	1.2	10.7
SE-Malmö	0.6	0.4	0.0	0.1	8.5	6.8
SE-Stockholm	1.0	0.7	0.1	0.1	6.9	7.8
SE-Sundsvall	1.5	1.2	0.0	0.0	3.1	9.6
Total	10.8	7.6	0.6	1.2		

Note: Wind and solar are day-ahead forecasts in GWh. Temperature in degrees Celsius at zone centroid. Sample period 2021–2024. Zones are sorted alphabetically.

The distribution of renewable generation capacity varies substantially across the region. Among the Nordic and Baltic zones, Finland has the highest wind output (3.3 GWh), followed by Denmark-Jutland and SE-Sundsvall (both 1.5 GWh), and SE-Luleå (0.6 GWh). Solar generation is negligible in most Scandinavian zones due to low irradiance, particularly during winter months

[1] See https://surfobs.climate.copernicus.eu/dataaccess/access_eobs.php. In the regressions, I use daily mean, minimum, and maximum temperatures to capture both level effects and within-day variation.

when electricity demand peaks.

Temperature patterns follow a clear latitudinal gradient. Northern zones such as NO-Tromsø average below zero (-1.8C), while southern zones such as SE-Malmö and DK-Jutland average around $8-9$C. The high standard deviations, ranging from 6 to 11 degrees, reflect pronounced seasonal variation. These temperature differences matter for electricity demand, as heating load in the Nordic countries drives much of the winter consumption.

Since unplanned outages are by definition unexpected, they should be orthogonal to these weather-driven variables. In principle, this means that including them as controls should not affect the estimated coefficients on outages. However, adding controls can improve precision by absorbing residual variation in prices, and provides a useful specification check: if the outage coefficients change substantially when controls are added, this would raise concerns about the exogeneity assumption. I return to this point in the discussion of the empirical strategy below.

Demand and supply

Table 4 reports descriptive statistics for demand and two categories of dispatchable generation: reservoir hydropower and thermal production. These variables serve as dependent variables in the supply response analysis, where I examine how other generators adjust output in response to nuclear outages.

Demand is concentrated in the larger zones. Finland has the largest demand in the sample with mean hourly consumption of 9.2 GWh, comparable to SE-Stockholm (9.7 GWh). The Norwegian and remaining Swedish zones have lower demand, ranging from 1.2 to 4.1 GWh. Total demand across the sample zones averages 46.9 GWh.

Hydropower production is concentrated in Norway and Sweden, reflecting the region's abundant reservoir capacity. The largest hydro zones are NO-Kristiansand (4.8 GWh), SE-Luleå (4.2 GWh), and NO-Bergen (3.2 GWh). The Baltic states and Denmark have negligible reservoir capacity. Total hydro output averages 21.2 GWh.

Thermal generation shows a different geographic pattern. Finland has the largest thermal output in the sample (10 GWh), which includes nuclear generation from Olkiluoto and Loviisa. The

Nordic countries have minimal thermal capacity outside of Finland, consistent with their reliance on hydropower and, in Sweden's case, nuclear generation.

Table 4: Demand and production by bidding area

	Demand		Hydro		Thermal	
	Mean	SD	Mean	SD	Mean	SD
DK-Jutland	2.5	0.4	0.0	0.0	1.0	0.6
DK-Zealand	1.5	0.3	0.0	0.0	0.8	0.5
Estonia	0.9	0.2	0.0	0.0	0.5	0.3
Finland	9.2	1.6	0.0	0.0	10.9	8.4
Latvia	0.8	0.2	0.0	0.0	0.3	0.2
Lithuania	1.4	0.3	0.1	0.1	0.3	0.2
NO-Bergen	1.9	0.3	3.2	1.2	0.1	0.0
NO-Kristiansand	4.1	0.7	4.8	2.0	0.0	0.0
NO-Oslo	3.9	1.3	1.0	0.5	0.0	0.0
NO-Tromsø	2.2	0.4	2.4	0.9	0.1	0.1
NO-Trondheim	3.2	0.5	1.8	0.6	0.0	0.0
SE-Luleå	1.2	0.2	4.2	1.2	0.0	0.0
SE-Malmö	2.6	0.6	0.2	0.1	0.1	0.1
SE-Stockholm	9.7	2.1	2.3	1.0	0.3	0.4
SE-Sundsvall	1.7	0.4	1.2	0.4	0.1	0.1
Total	46.9	8.9	21.2	6.0	14.5	8.6

Note: All variables in GWh. Hydro refers to reservoir hydropower. Thermal includes gas, coal, oil, biomass, and nuclear generation, but excludes Swedish nuclear. Sample period 2021–2024. Zones are sorted alphabetically.

4 Econometric model

4.1 Main specification

To estimate the effect of nuclear outages on electricity prices and related outcomes, I employ the following specification:

$$Y_t = \alpha + \beta \, outage_t + \boldsymbol{\gamma}'\mathbf{X}_t + h_t + dow_d + m_m + \theta \, maintenance_t + \varepsilon_t \tag{1}$$

where Y_t denotes the outcome variable in hour t, and α is a constant. The coefficient of interest is β, associated with $outage_t$, which measures unplanned nuclear capacity unavailability in GW. I construct this variable taking into account the timing of the day-ahead market: since the auction clears at noon for delivery during the following day, an outage occurring before noon can first affect prices starting at midnight that night (a 12–24 hour lag), while an outage occurring after noon can first affect prices starting at midnight the following night (a 24–36 hour lag). I set the outage variable to zero during the initial hours before it can influence the day-ahead price.

The vector $\mathbf{X}_t$ includes zone-specific hourly control variables: day-ahead forecasts of wind and solar output, and daily mean, minimum, and maximum temperature. I include hour-of-day fixed effects h_t and day-of-week fixed effects dow_d to absorb regular demand patterns, and month-of-sample fixed effects m_m to control for slower-moving factors such as fuel prices, hydrological conditions, and seasonal demand. Last, I also control for maintenance (in GW), to account for contemporaneous supply-side availability constraints, although the associated coefficient should not be interpreted causally. Standard errors are clustered at the month-of-sample level to account for serial correlation. Compared to Newey-West standard errors with bandwidth $S = 1.3\sqrt{T} \approx 273$ as recommended by Lazarus et al. (2018), the cluster-robust standard errors are approximately 20 percent larger (results available on request).

I estimate separate regressions for each of the 15 price zones, meaning that $\hat{\beta}$ is an estimate of the price increase from a 1 GW outage in the relevant zone, with other hours in the same zone and month-of-sample serving as the control group.

Dynamic effects

The baseline specification imposes a constant effect throughout the duration of an outage. However, there is no clear *a priori* reason why the price effect should remain stable over time. If other market participants need time to respond to an outage (for instance, by ramping up hydropower or thermal generation), the effect may be largest at the outset and diminish as supply adjusts. Conversely, if the initial supply response draws down water reservoirs, the opportunity cost of generation may rise over time, leading to larger price effects as the outage persists.

To examine how the price effect evolves, I estimate a modified specification that allows separate effects by day of outage:

$$Y_t = \alpha + \sum_{d=1}^{10} \beta_d \left(outage_t \times \mathbf{1}[day_t = d] \right) + \beta_{11+} \left(outage_t \times \mathbf{1}[day_t \geq 11] \right) + \gamma' \mathbf{X}_t + h_t + dow_d + m_m + \varepsilon_t \tag{2}$$

where day_t denotes the number of days since the current outage began. The coefficients $\beta_1, \ldots, \beta_{10}$ capture the price effect per GW on each day of the outage, while β_{11+} captures the average effect for outages lasting beyond ten days. Since shorter outages are more common, estimates for later days are identified from fewer, typically larger, events. As I do not find statistically significant heterogeneity across days, I estimate this specification only for SE-Stockholm and do not incorporate dynamic effects in the welfare calculations.

4.2 Restricted sample with unconstrained transmission

The main specification pools all hours regardless of transmission conditions. However, when transmission lines are congested, price effects from nuclear outages in SE-Stockholm will not transmit to neighboring zones. To see why, consider SE-Stockholm exporting at full transmission capacity to a neighboring zone. If an outage occurs but transmission remains congested, the neighboring zone still receives the same quantity of imports. The price in the neighboring zone is determined by its own supply-demand balance given this fixed import quantity—not by the cost of the imported electricity. Although the outage raises the cost of generation in SE-Stockholm, this does not affect the neighboring zone's price as long as transmission remains constrained.

This reasoning applies to immediate price effects. Over longer horizons, there may be indirect effects: if nuclear output is replaced by hydropower, reservoir levels fall, potentially raising future prices in interconnected zones. The present analysis focuses on short-run price effects and does not capture such dynamic adjustments.

To obtain estimates that are not attenuated by congested hours, I estimate an alternative specification that restricts the sample to hours when markets are likely to be integrated. Conditioning on hours when prices are *realized* to be equal would introduce endogeneity: an outage can itself cause or relieve transmission constraints. For instance, if SE-Stockholm is exporting under congestion, an outage reduces exports, potentially relieving the constraint and equalizing prices. In such cases, conditioning on realized same-price hours would exclude the pre-outage period from the sample, making it impossible to identify the effect. To avoid this problem, I instead predict which hours are likely to exhibit equal prices using only exogenous variables, and then restrict the sample based on these predictions.

For each bidding zone i, I estimate the following linear probability model:

$$S_t = \alpha + \boldsymbol{\delta}'\mathbf{Z}_t + h_t + dow_d + m_m + \nu_t \tag{3}$$

where S_t is an indicator equal to unity if the price in zone i in hour t equals the price in SE-Stockholm. The vector $\mathbf{Z}_t$ includes day-ahead wind forecasts and temperatures for both SE-Stockholm and zone i. Crucially, the outage variable is excluded from this prediction equation since it is the treatment of interest. I then include hour t in the restricted sample for zone i if the predicted probability exceeds 0.5. I use OLS rather than logit to avoid the incidental parameters problem that arises with many fixed effects.

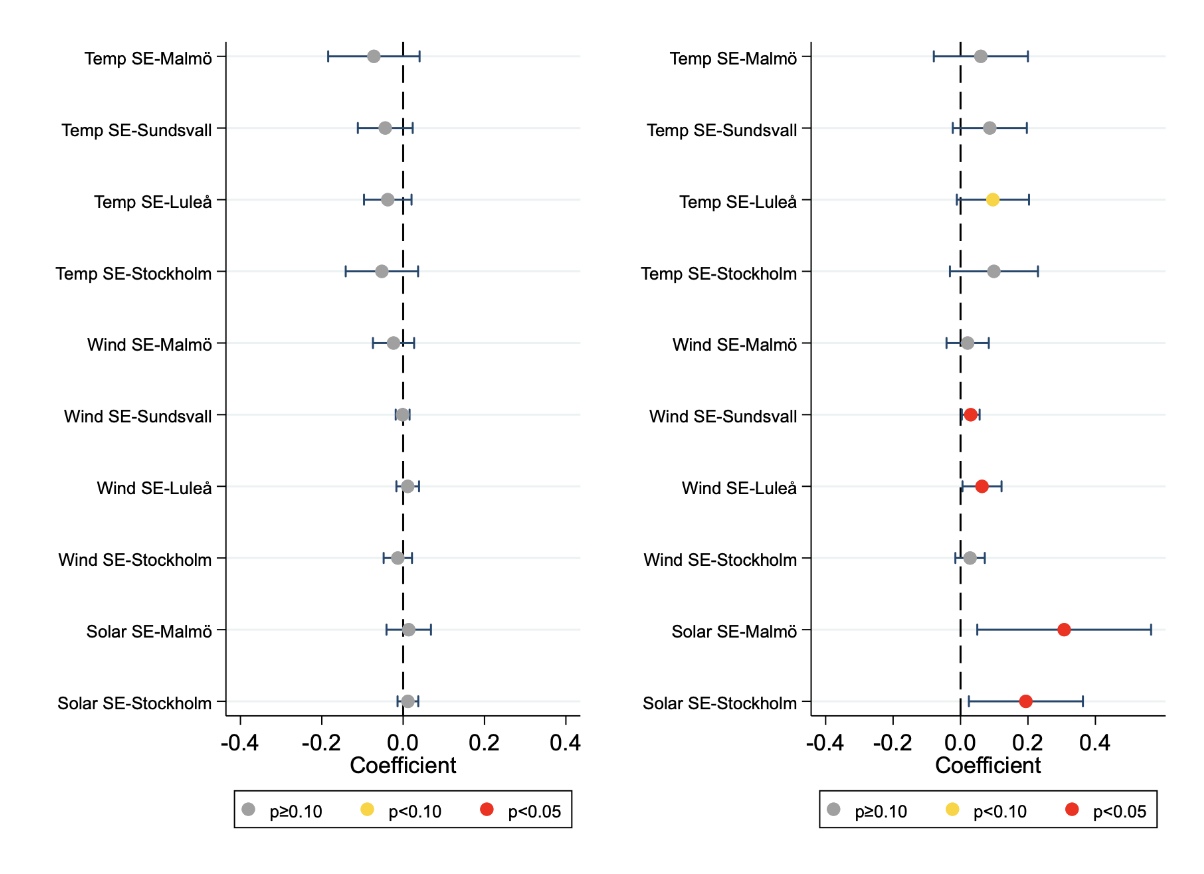
4.3 Exogeneity of outages

The identifying assumption is that unplanned nuclear outages are exogenous to contemporaneous demand and supply conditions. This assumption is plausible given the nature of unplanned outages: they arise from equipment failures, safety system trips, and other technical malfunctions that are largely unpredictable and unrelated to market conditions. In contrast, planned maintenance is strategically scheduled during periods of low expected demand and favorable conditions for alternative generation, making it endogenous to the very factors that determine prices.

To provide evidence supporting this assumption, I iteratively regress the outage variable on each of the exogenous control variables mean temperature, wind production, and solar production, for each of the Swedish price zones (solar is excluded for the most northern zones since output quantities are trivial). Figure 4 presents the results when including fixed effects for hour-of-day, day-of-week, and month-of-sample. The left panel shows coefficients for unplanned outages: none of the variables significantly predict unplanned outage levels. The right panel repeats the exercise for planned maintenance, which shows a different pattern: planned maintenance is positively correlated with temperature and solar output, consistent with operators scheduling maintenance during periods when residual demand is lower.

This contrast reinforces the identification strategy. Unplanned outages provide plausibly exogenous variation in nuclear supply, while planned maintenance would confound estimates due to its correlation with seasonal demand and supply conditions. In the main specifications, I therefore focus on unplanned outages, though I include planned maintenance as a control variable to absorb its potentially confounding effect on prices.

Figure 4: Exogeneity of outages



Note: Dependent variable: Unplanned outages (left), Planned maintenance (right). Hour-of-the-day, day-of-week, and month-of-sample fixed effects are included in each regression.

5 Results

5.1 Price response

Price response in SE-Stockholm

Results from the main specification applied to SE-Stockholm are presented in Table 5. Column (1) reports estimates without month-of-sample fixed effects or controls, yielding a coefficient of 13.2 EUR/MWh that is imprecisely estimated and statistically indistinguishable from zero. The large standard error likely reflects the substantial price volatility during the sample period, driven by factors such as the 2022 energy crisis, fluctuating gas prices, and varying hydrological conditions. Adding month-of-sample fixed effects in column (2) absorbs this variation, increasing the coefficient to 20.0 EUR/MWh and substantially improving precision. Column (3) introduces weather controls, including wind and solar forecasts along with temperature variables, which reduces the coefficient to 16.2 EUR/MWh while further tightening the standard errors. The preferred specification in column (4) adds planned maintenance as a control, yielding a coefficient of 16.9 EUR/MWh. The stability of the coefficient across columns (3) and (4) provides informal support for the exogeneity of unplanned outages.

Column (5) adds an interaction between outages and peak hours (08:00-17:00), *Outage x peak hour*, to test whether price effects are larger during hours of the day when demand is generally higher. The interaction term is small and statistically insignificant, suggesting that the price effect is comparatively uniform within the day.

Table 5: Effect of outages on prices in zone SE-Stockholm

	(1)	(2)	(3)	(4)	(5)
Outage	13.2	20.0**	16.2**	16.9***	16.9***
	(8.22)	(8.23)	(6.21)	(6.18)	(5.51)
Wind			-28.6***	-28.8***	-28.8***
			(3.28)	(3.32)	(3.32)
Solar			-34.1***	-35.1***	-35.1***
			(9.20)	(9.08)	(9.05)
Mean temp			-1.56*	-1.57*	-1.57*
			(0.92)	(0.92)	(0.92)
Max temp			-0.23	-0.39	-0.39
			(0.78)	(0.80)	(0.80)
Min temp			-1.72**	-1.60**	-1.60**
			(0.70)	(0.67)	(0.67)
Planned maintenance				7.55**	7.55**
				(3.57)	(3.57)
Outage x peak hour					-0.088
					(4.58)
Month-of-sample FE	No	Yes	Yes	Yes	Yes
Adj R^2	0.31	0.49	0.58	0.58	0.58

* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$
Note: Dependent variable is the day-ahead price in EUR/MWh. Outage is measured in GW of unavailable nuclear capacity. All specifications include hour-of-day and day-of-week fixed effects. Standard errors clustered at the month level in parentheses. N=35,064.

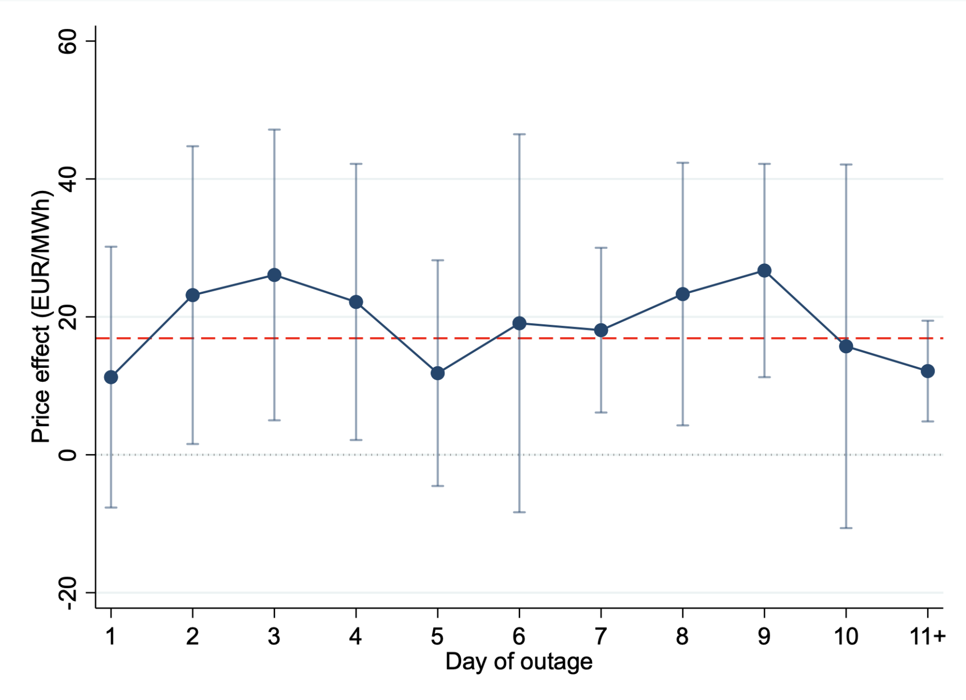
Dynamic effects

Figure 5 presents estimates from the dynamic specification, showing how the price effect evolves over the course of an outage. The coefficients fluctuate between approximately 11 and 26 EUR/MWh across days 1 through 10, with the pooled estimate for days 11 and beyond at around 12 EUR/MWh. All point estimates fall within the 95 percent confidence interval of the baseline estimate (4.8 to 29.0 EUR/MWh), indicated by the dashed horizontal line.

The confidence intervals for the daily coefficients are wider than for the baseline estimate, since each coefficient is identified from a smaller subset of observations. The confidence interval for the 11+ coefficient is somewhat narrower than for the individual daily coefficients, as it pools observations from all days beyond the tenth.

There is no evidence of a systematic trend. The price effect neither diminishes over time (as would be expected if other generators gradually ramped up supply) nor increases (as would occur if reservoir depletion raised the opportunity cost of hydropower). Instead, the effect appears constant throughout the outage duration, supporting the assumption of a time-invariant effect embedded in the baseline specification.

Figure 5: Dynamic effects



Note: The figure shows estimated price effects by day of outage from equation (2). The dashed line indicates the baseline estimate of 16.9 EUR/MWh. Error bars represent 95 percent confidence intervals based on standard errors clustered at the month-of-sample level.

Price effects in the remaining zones

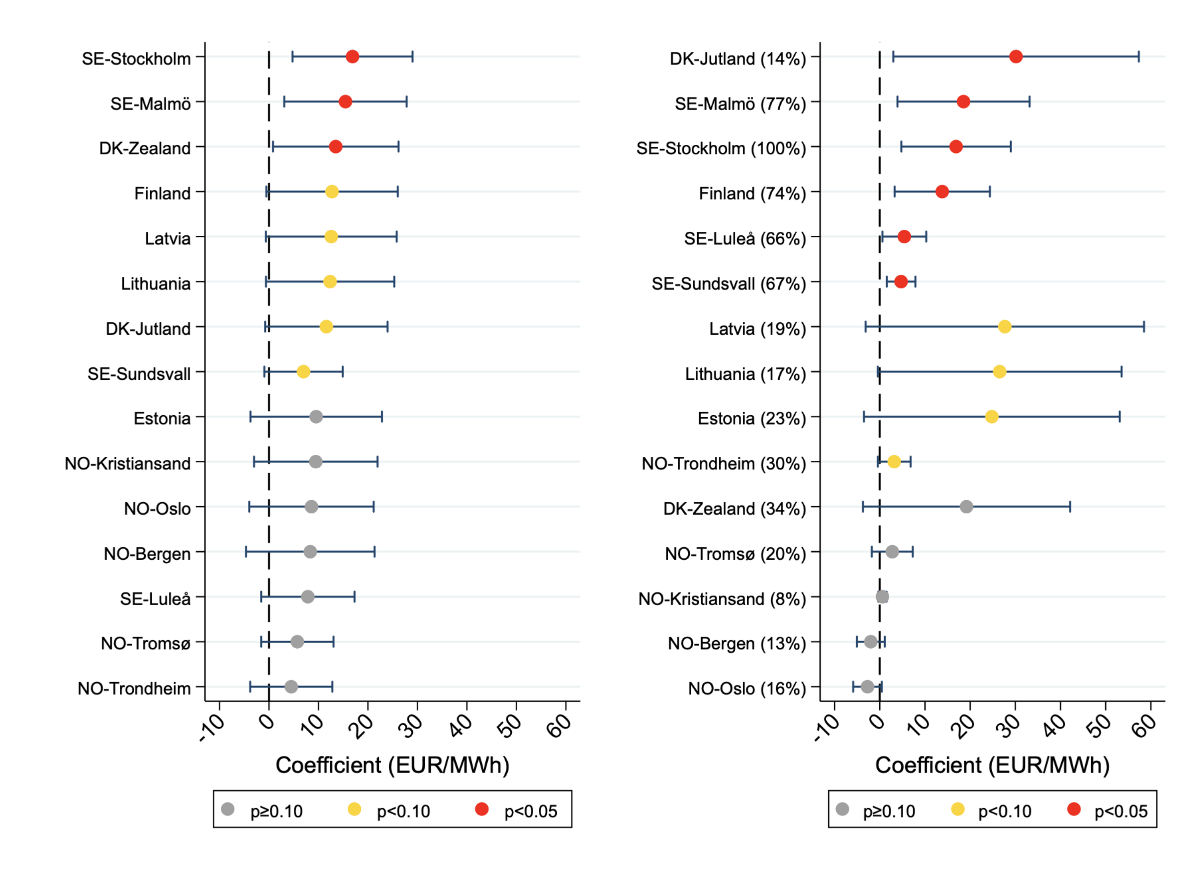
Figure 6 presents coefficient estimates from the preferred specification applied to each bidding zone. Zones are ordered by statistical significance, with highly significant estimates ($p < 0.05$) at the top, followed by marginally significant ($p < 0.10$) and insignificant ($p \geq 0.10$) estimates.

Within each significance group, zones are ordered from highest to lowest coefficient.

The left panel shows results from the full sample. SE-Stockholm and SE-Malmö exhibit the largest significant effects, with coefficients around 17 and 15 EUR/MWh respectively. DK-Zealand also shows significant positive effects of similar magnitude. Finland, Latvia, Lithuania, DK-Jutland, and SE-Sundsvall display marginally significant positive coefficients. The Norwegian zones show positive but imprecisely estimated effects.

The right panel presents estimates from the restricted sample, limited to hours when prices are predicted to equal SE-Stockholm. The share of included hours, shown in parentheses, varies substantially across zones. For zones that are frequently integrated with SE-Stockholm, such as SE-Malmö (77 percent) and Finland (74 percent), the coefficients are somewhat larger than in the full sample, consistent with reduced attenuation bias. The northern Swedish zones SE-Luleå and SE-Sundsvall, which retain around two-thirds of observations, now show significant positive effects of approximately 12 EUR/MWh. The Baltic states exhibit larger point estimates of around 25–28 EUR/MWh but with wider confidence intervals due to their smaller sample shares of 17–23 percent. DK-Jutland shows a large coefficient of approximately 30 EUR/MWh, but estimated using only 14 percent of hours, so this result should be interpreted with caution. The Norwegian zones retain only 8–20 percent of observations and show small or slightly negative coefficients that are statistically insignificant.

Figure 6: Price effects by bidding zone

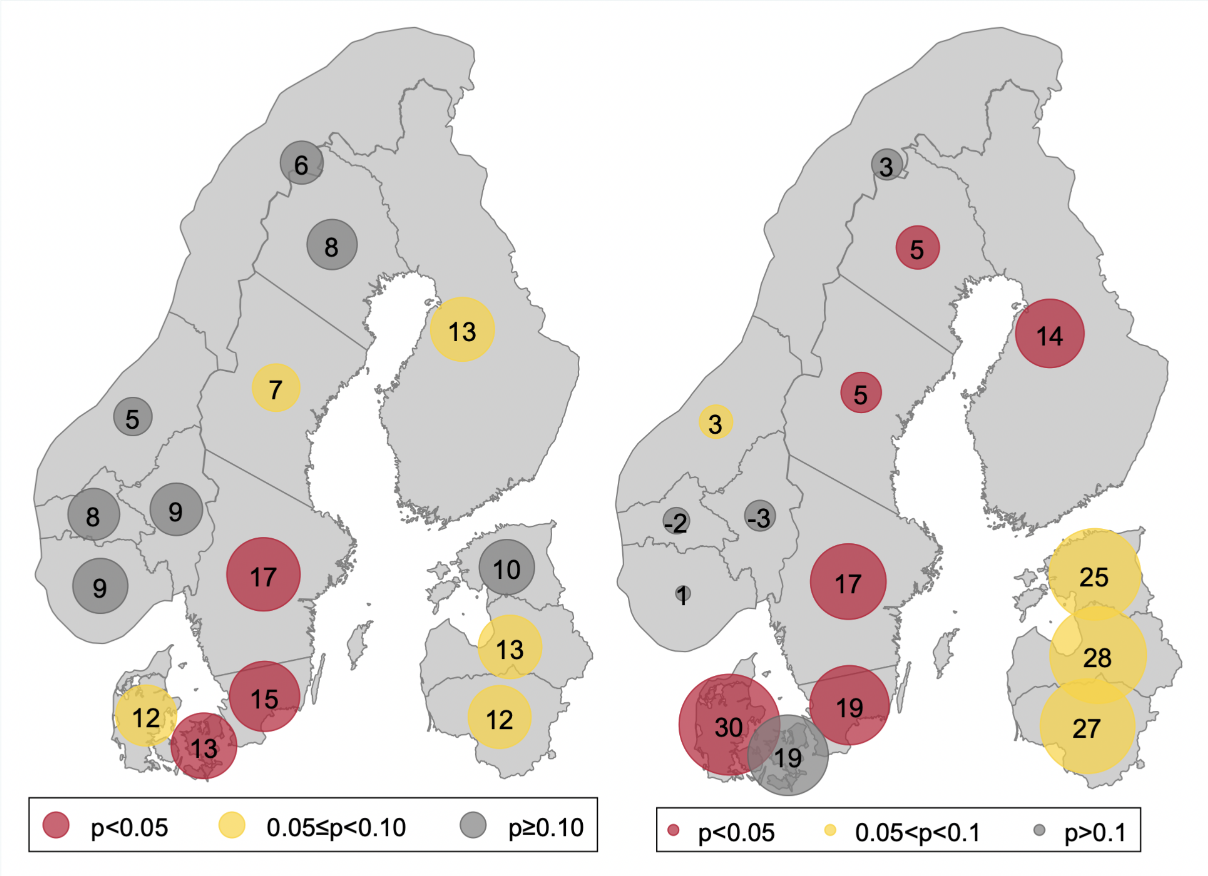


Note: Coefficient estimates from equation (1) with day-ahead price as the dependent variable. Left panel: full sample. Right panel: restricted to hours when prices are predicted to equal SE-Stockholm, with share of included hours in parentheses. Zones ordered by significance level, then by coefficient magnitude within each group. Bars indicate 95 percent confidence intervals. Standard errors clustered at the month level.

Figure 7 displays the spatial distribution of the estimated coefficients. The left panel shows the full-sample results, with the largest effects concentrated in southern Sweden, Denmark, and Finland. The right panel shows the restricted-sample results, revealing a clearer pattern: when transmission constraints do not bind, price effects are relatively uniform across the Nordic and Baltic region, while effects attenuate toward continental Europe where market integration with SE-Stockholm is less frequent.

Given the exceptionally high electricity prices observed in 2022 following Russia's invasion of Ukraine, I re-estimate the baseline specification excluding that year. Figure A3 shows that coefficient magnitudes decline by approximately 40 percent, while the relative geographic dispersion of the effects remains largely unchanged.

Figure 7: Map of price effects: full sample (left) and restricted sample (right)



Note: Coefficient estimates from equation (1) with day-ahead price as the dependent variable. Left panel: full sample. Right panel: restricted to hours when prices are predicted to equal SE-Stockholm. Circle size proportional to coefficient magnitude. Colors indicate significance level: red ($p < 0.05$), yellow ($p < 0.10$), gray ($p \geq 0.10$).

Placebo test

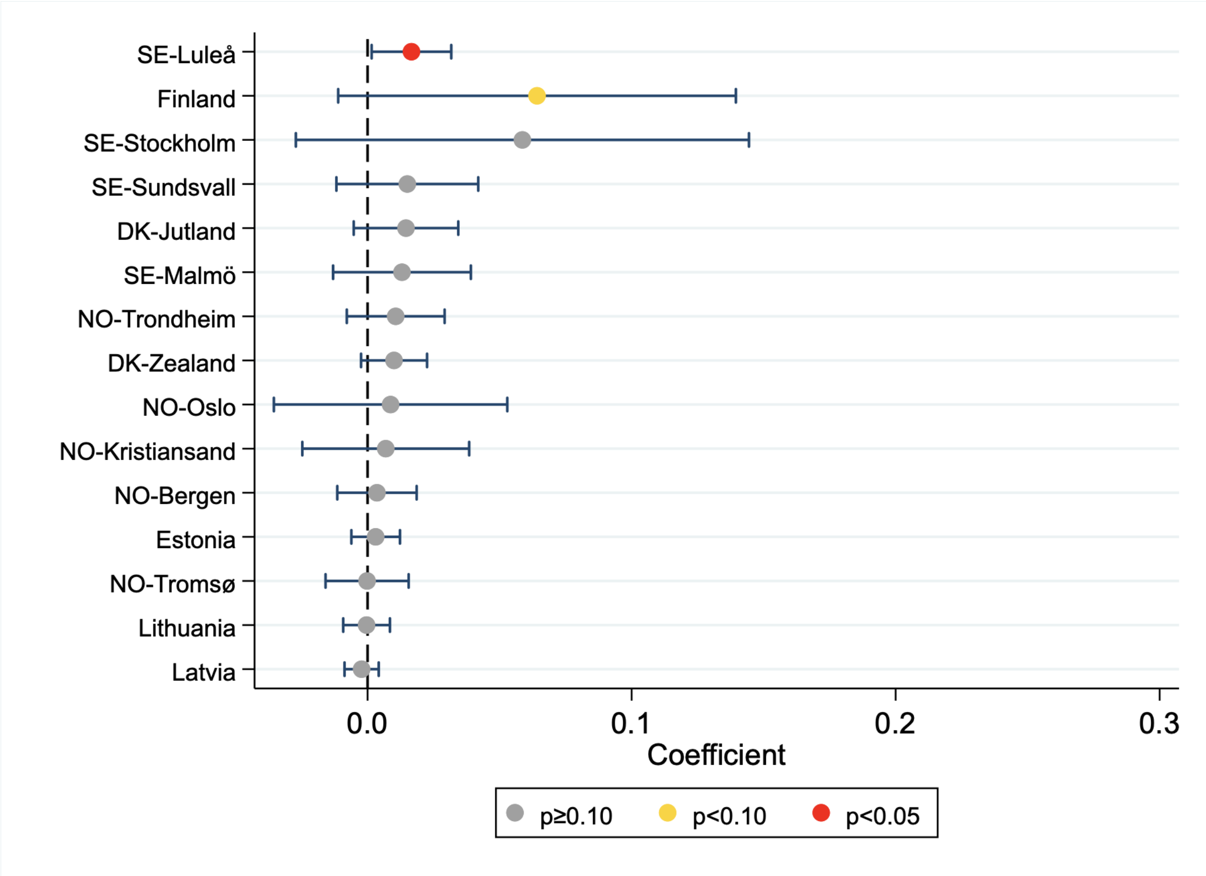
To further assess the validity of the identification strategy, I conduct a placebo test by shifting the timing of outages. Figure A4 displays the results. The left panel shows estimates when each outage is assumed to have occurred one week before its actual start date; the right panel shows estimates when outages are shifted one week forward. If the main results were driven by some omitted variable correlated with both outages and prices, we would expect to find significant effects in these placebo regressions as well. Instead, all coefficients but one are statistically insignificant at conventional levels. The single marginally significant coefficient, at approximately -3 EUR/MWh, is economically negligible compared to the main effect of 17 EUR/MWh in SE-Stockholm. These results support the interpretation that unplanned outages represent genuinely exogenous supply shocks.

5.2 Demand response

Before examining the demand response estimates, it is useful to consider why we should expect demand to be approximately inelastic at the hourly level. In the Nordic countries, many residential and commercial consumers have contracts with full pass-through from wholesale to retail prices, but the pass-through is typically constructed so that the monthly retail price equals a volume-weighted average of spot prices during that month. Crucially, the weighting is based on total consumption in the bidding zone, not the individual consumer's consumption profile. This means that even if a consumer reduces demand during a high-price hour, their per-kWh price does not change. In Central Europe and the Baltic states, fixed-price contracts are more common, where the retail price is set for extended periods regardless of spot price movements. Under both arrangements, consumers face no incentive to adjust demand in response to hourly price variation.

Some industrial consumers do face real-time pricing and could in principle respond to spot price changes. However, industrial processes typically have high adjustment costs, and demand response is triggered only during extreme price spikes. A price increase of approximately 15 EUR/MWh, while economically meaningful for welfare calculations, is unlikely to exceed the threshold required for industrial consumers to curtail production.

Figure 8: Demand response by bidding zone



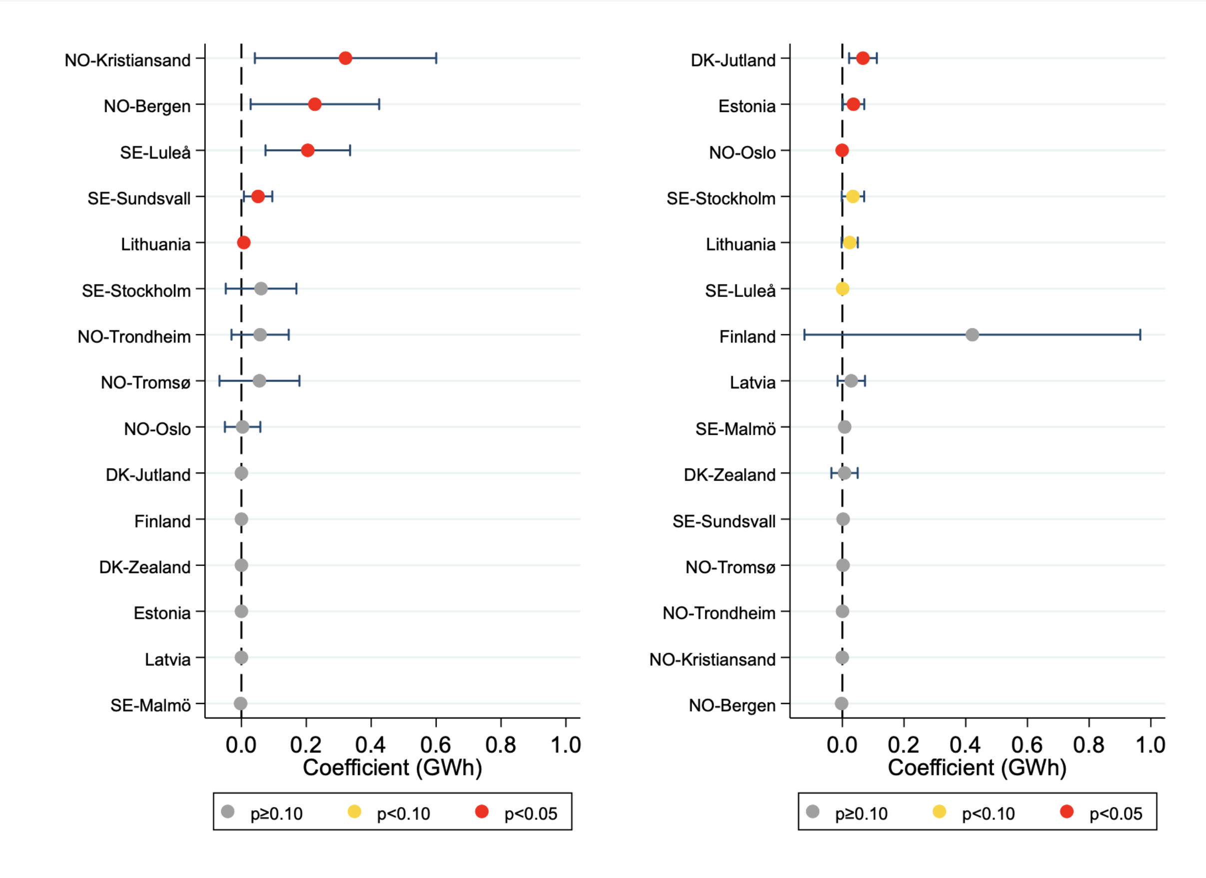
Note: Coefficient estimates from equation (1) with zone consumption as the dependent variable. Zones ordered by significance level, then by coefficient magnitude within each group. Bars indicate 95 percent confidence intervals. Standard errors clustered at the month level.

Figure 8 presents the results from estimating the same specification as for the price response, but using hourly consumption as the dependent variable. Consistent with the institutional setting, nearly all coefficients are small and statistically insignificant. SE-Luleå displays a small but statistically significant positive coefficient, which likely reflects increased transmission losses when outages change flow patterns and increase imports from more distant generators. Finland shows a somewhat larger positive coefficient that is marginally significant. This result is somewhat unexpected given the institutional setting. The magnitude remains economically small relative to the 1 GW outage, but the effect is larger than what transmission losses alone would plausibly account for.

5.3 Supply response

With demand approximately inelastic, the lost nuclear output must be replaced by other generation sources. Figure 9 presents supply response estimates separately for hydropower and the remaining thermal generation.

Figure 9: Supply response by bidding zone: hydropower (left) and thermal (right)

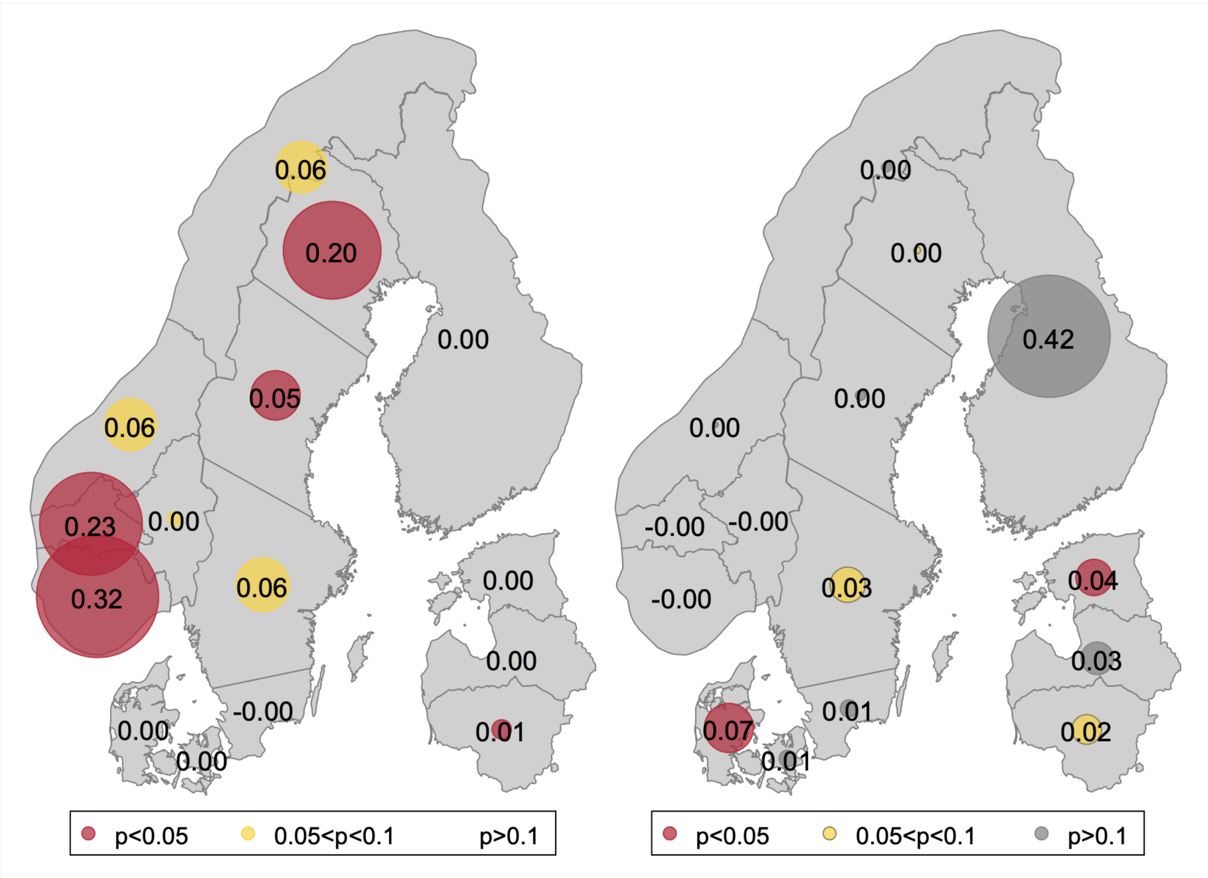


Note: Coefficient estimates from equation (1) with zone production as the dependent variable. Zones ordered by significance level, then by coefficient magnitude within each group. Bars indicate 95 percent confidence intervals. Standard errors clustered at the month level.

The left panel shows hydropower responses. Norwegian zones exhibit the largest effects: NO-Kristiansand and NO-Bergen increase output by approximately 0.3 and 0.25 GWh respectively per GW of nuclear outage ($p < 0.05$ for both). Northern Swedish zones also contribute, with SE-Luleå showing a coefficient of around 0.2 GWh ($p < 0.05$) and SE-Sundsvall around 0.05 GWh ($p < 0.05$). Lithuania displays a small but significant ($p < 0.05$) positive coefficient. The remaining zones show small and statistically insignificant effects. These results are consistent with the abundant hydropower reserves in Norway and northern Sweden, which can be dispatched flexibly in response to price signals from neighboring markets.

The right panel shows thermal generation responses. The coefficients are generally smaller in magnitude. DK-Jutland, Estonia, and NO-Oslo show significant ($p < 0.05$) positive effects, with DK-Jutland exhibiting the largest coefficient of approximately 0.07 GWh. SE-Stockholm, Lithuania and SE-Luleå display marginally significant ($p < 0.10$) positive responses that are all economically insignificant. The coefficients associated with the remaining zones are statistically insignificant. Out of these, all coefficients except for the one associated with Finland is also economically insignificant. Figure 10 displays the supply response coefficients geographically.

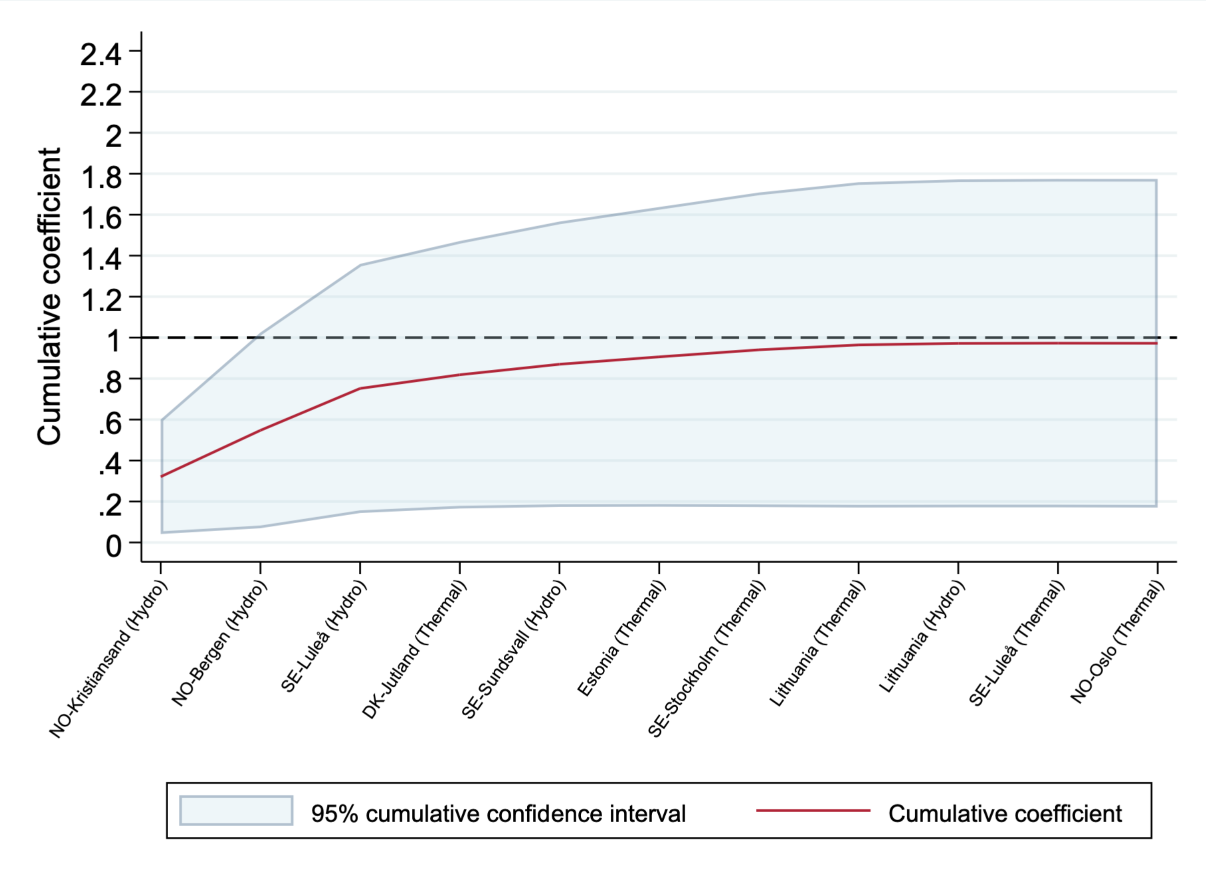
Figure 10: Map of supply response: hydropower (left) and thermal (right)



Note: Coefficient estimates from equation (1) with zone production as the dependent variable. Circle size proportional to coefficient magnitude. Colors indicate significance level: red ($p < 0.05$), yellow ($p < 0.10$), gray ($p \geq 0.10$).

Figure 11 presents the cumulative supply response, summing coefficients across zones and generation types for sources with p-values below 0.10. The cumulative coefficient reaches approximately 1 GWh, indicating that the estimated supply responses roughly account for the full nuclear short-fall. The 95 percent confidence interval is wide but consistent with full replacement of the lost generation.

Figure 11: Cumulative supply response



Note: Cumulative sum of coefficient estimates for hydropower and thermal generation. Only coefficients with $p < 0.10$ are included. Shaded area indicates 95 percent cumulative confidence interval.

The geographic pattern of supply and price responses reveals an important economic relationship. Norwegian zones exhibit large supply responses but relatively small and imprecisely estimated price effects, while Swedish zones (particularly SE-Stockholm) show large price effects but limited domestic supply response. This pattern is consistent with differences in supply elasticity across the interconnected market. Norwegian hydropower can adjust output flexibly in response to price signals, meaning that quantity adjustments partially absorb the shock and dampen the local price effect. Sweden, by contrast, lacks flexible substitutes for the lost nuclear capacity, so the adjustment occurs primarily on the price margin. The small price effect in Norway thus reflects not weak integration, but rather strong integration combined with elastic supply: Norwegian generators respond to Swedish scarcity by exporting more (or importing less), which limits their own price increase while also moderating the price spike in Sweden.

The dominance of Norwegian hydropower in the supply response has an important implication for interpreting the consumer surplus calculations that follow. When Norwegian generators increase output to compensate for Swedish nuclear shortfalls, they draw down reservoir levels, which raises the opportunity cost of water and thereby prices in subsequent periods. This effect is strongest in Norway where the reservoirs are located, but transmits to interconnected markets as well. The present analysis captures only the instantaneous price effect and does not trace these intertemporal dynamics. Since the supply substitution comes predominantly from Norwegian rather than Swedish hydropower, this limitation implies that I underestimate the international component of the total price effect. Had Swedish hydro instead provided most of the substitution, the bias would run in the opposite direction, understating the Swedish share. For the purposes of this paper, which argues that the international share of consumer surplus effects is non-trivial, the conservative nature of this bias strengthens rather than weakens the main conclusion.

As a robustness check, I also estimate the supply response using the restricted sample of hours when prices are predicted to equal SE-Stockholm. The results, presented in Figure A5, are qualitatively similar but less precisely estimated due to the reduced sample size. Norwegian and Swedish hydropower continue to show positive responses, as does thermal generation in Denmark and the Baltics.

5.4 Welfare effects

A nuclear outage affects welfare through several channels. The most direct is a loss in productive efficiency: nuclear generation, which has low marginal cost, must be replaced by units higher on the merit order. In the very short run, the supply response analysis in Section 5.3 shows that most of this substitution comes from Nordic hydropower, whose marginal production cost is low but whose opportunity cost (the value of water in future periods) is non-trivial. Over a longer horizon, as reservoir levels decline and hydro producers internalize the higher opportunity cost, the substitution shifts toward conventional thermal plants with substantially higher fuel costs. The true resource cost of the outage is the difference in production cost between the replacement units and nuclear, net of any nuclear fuel saved from not operating the plant. Estimating this cost is beyond the scope of the paper, since it requires tracing the full dynamic substitution pattern across generation technologies and time periods.

In addition to this efficiency loss, the price increase induced by the outage generates transfers between market participants. Consumers pay more for each unit of electricity, while infra-marginal generators (those that would have produced regardless of the outage) earn higher revenues. TSO congestion revenues also change as both cross-border price differences and the volume of trades shift. These transfers wash out in aggregate welfare but matter for the cross-border distribution of costs and gains. The ownership structure of Nordic generators complicates the national attribution further: Vattenfall is Swedish state-owned, Fortum is Finnish, and Uniper is German, so producer surplus gains do not map cleanly onto national borders. A complete welfare accounting would trace all of these channels, but is beyond the scope of this study.

In what follows, I focus on consumer surplus, which I can estimate credibly from the price response regressions. This focus is motivated by two considerations. First, consumer surplus losses are the most directly policy-relevant quantity for the generation adequacy coordination problem that motivates the paper: it is consumer costs, not producer revenues, that drive national governments' adequacy decisions. Second, because short-run electricity demand is approximately inelastic over the relevant price range, changes in consumer surplus are well approximated by the price change multiplied by the quantity consumed, making the calculation straightforward and transparent. It should be noted, however, that the consumer surplus estimates do not constitute a complete welfare analysis. They capture the cost borne by consumers but not the offsetting gains accruing to producers and TSOs, and they do not account for the real resource cost of productive inefficiency.

For each zone i and hour t, I calculate the change in consumer surplus as:

$$\Delta CS_{it} = \hat{\beta}_i \times \text{outage}_t \times \text{consumption}_{it} \tag{4}$$

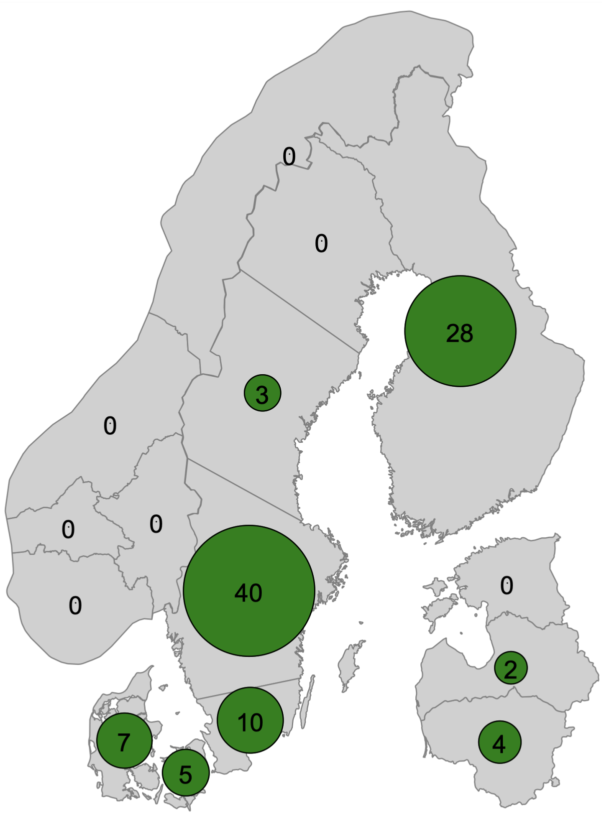
where $\hat{\beta}_i$ is the estimated price response coefficient from equation (1), outage_t is the amount of unavailable nuclear capacity in hour t, and consumption_{it} is the quantity consumed in zone i during hour t (where consumption is expressed in MWh).

I aggregate these hourly effects over the sample period to obtain total consumer surplus losses by zone, expressed as a percentage of the total. Figure 12 displays this distribution. The results reveal that Swedish nuclear outages impose substantial costs on consumers outside Sweden. Under the baseline specification, which excludes statistically insignificant spillover coefficients ($p \geq 0.10$), Swedish consumers bear 53 percent of the total loss in consumer surplus, with the SE-Stockholm zone alone accounting for 40 percent, SE-Malmö 10 percent, and SE-Sundsvall 3 percent. The remaining 47 percent falls on consumers in neighboring countries. Including all estimated spillover effects regardless of statistical significance reduces the Swedish share to 42 percent, suggesting that the baseline estimate is conservative regarding the magnitude of cross-border spillovers.

While the distributional shares are of primary interest, being more robust to model specification than absolute magnitudes, the total consumer surplus losses are also informative. Under the baseline specification, the aggregate loss in consumer surplus amounts to approximately 0.9 billion EUR per year across all affected zones (corresponding to 3 percent of total market turnover). Including all estimated coefficients regardless of statistical significance raises this figure to 1.2 billion EUR .

Several factors omitted from the analysis all suggest that the estimated Swedish share overstates the true Swedish share of total consumer surplus losses. First, Germany and Poland are excluded despite being interconnected with the Nordic system; to the extent that Swedish outages raise prices in these markets, the foreign share increases. Second, almost the entire sample period predates the introduction of flow-based capacity allocation in October 2023, which increased cross-border trading capacity and is likely to strengthen price spillovers going forward. Third, Sweden's share of Nordic balancing market procurement is lower than its estimated share of day-ahead consumer surplus losses. Fourth, the dominant supply response to outages comes from Norwegian rather than Swedish hydropower, implying that the intertemporal costs of reservoir depletion, in the form of higher prices as reservoir levels decline, fall disproportionately on Norwegian and northern Swedish consumers. Since all four omissions bias in the same direction, the estimated Swedish share of 42–53 percent should be regarded as an upper bound with respect to these factors.

Figure 12: Distribution of consumer surplus losses by bidding zone



Note: Numbers indicate each zone's share (in percent) of total short-run consumer surplus losses from Swedish nuclear outages. Circle sizes are proportional to the share.

Finland bears the largest foreign share at 28 percent, reflecting both its strong price integration with SE-Stockholm and substantial consumption. Denmark accounts for 12 percent, split between DK-Jutland (7 percent) and DK-Zealand (5 percent). The Baltic states collectively bear 6 percent, with Lithuania at 4 percent and Latvia at 2 percent. Norwegian zones show zero consumer surplus effects, which follows directly from their insignificant price response coefficients.

These figures represent short-run consumer surplus effects and should be interpreted with appropriate caution. As discussed above, they do not capture producer surplus gains, TSO congestion revenues, or the real resource cost of replacing nuclear generation with more expensive alternatives. Moreover, the intertemporal effects of hydro reservoir depletion, which the contemporaneous estimates do not capture, are likely to increase the foreign share of consumer surplus losses further, as Norwegian and northern Swedish consumers face higher prices in subsequent periods when reservoir levels are drawn down.

6 Conclusion

This paper estimates the international price effects of unplanned Swedish nuclear outages using hourly data on day-ahead prices, generation, and consumption across 15 bidding zones in Northern Europe. I find that a 1 GW reduction in Swedish nuclear output raises day-ahead prices by approximately 17 EUR/MWh in the SE-Stockholm zone where all Swedish reactors are located. The effects extend substantially beyond Sweden: Finland experiences price increases of similar magnitude, while Denmark, Latvia, and Lithuania show smaller but statistically significant responses. In Norway, contemporaneous price effects are largely offset by increased hydro generation, though the resulting reservoir depletion implies intertemporal displacement of costs. Aggregating across zones, I estimate that Swedish consumers bear approximately half of the short-run consumer surplus losses from nuclear outages, with the remaining share falling on consumers in Finland, Denmark, and the Baltic states.

This distributional finding is robust across specifications and does not depend on the particular assumptions needed to calculate absolute consumer surplus magnitudes. Extending the welfare analysis beyond the contemporaneous effects, for instance to incorporate the intertemporal costs of reservoir depletion in the weeks following an outage, would require modeling hydropower optimization dynamics that are beyond the scope of this study. Since the dominant supply response comes from Norwegian rather than Swedish hydropower, such an extension would likely increase the estimated foreign share further.

Moreover, several factors omitted from the analysis, including spillovers to Germany and Poland; increased cross-border capacity under flow-based market coupling after the sample period; and balancing market costs, all suggest that the foreign share is, if anything, larger than what I estimate. The finding that approximately half of the consumer surplus consequences fall outside Sweden is therefore likely conservative.

These results have direct implications for how generation adequacy is assessed and managed in interconnected electricity markets. Current frameworks treat adequacy as a fundamentally national responsibility: each country sets its own standards, manages its own generation fleet, and procures its own reserves. The findings in this paper demonstrate that this national framing understates the true scope of adequacy interdependence. Supply disruptions in Sweden impose economically significant costs on consumers in neighboring countries, even during periods when the system is not under severe stress. Generation adequacy is, de facto, a regional rather than a national concern.

This interdependence creates a coordination problem. When countries evaluate investments in generation capacity on national cost-benefit grounds, they neglect the benefits that accrue to foreign consumers through integrated wholesale markets. The result may be regional underinvestment in firm capacity, even when such investment would pass a collective cost-benefit test. The finding that Finland alone accounts for 28 percent of consumer surplus effects illustrates the magnitude of these cross-border externalities. Mechanisms to internalize them, whether through joint adequacy assessments or coordinated capacity procurement, could improve regional welfare relative to purely national approaches.

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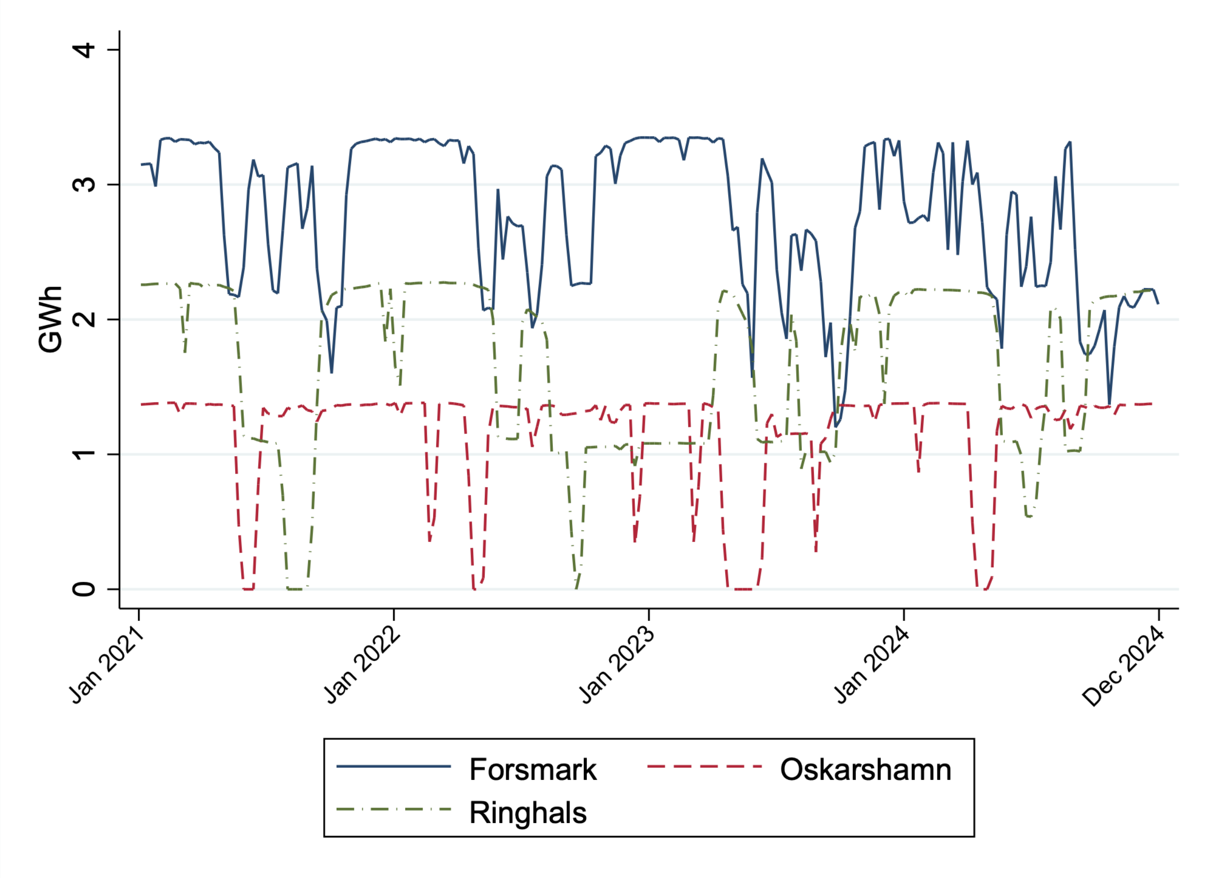
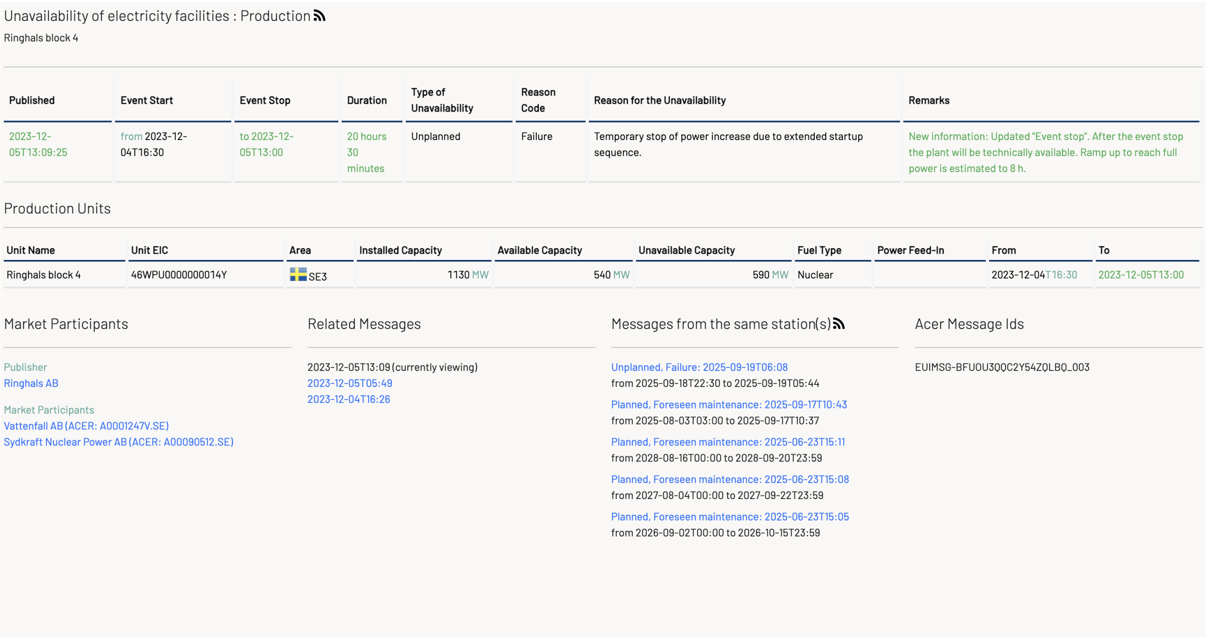
Appendix: Additional Figures

Figure A1: Observed plant level output



Note: Weekly averages of hourly generation by plant. Forsmark comprises three reactors (F1, F2, F3), Ringhals two reactors (R3, R4), and Oskarshamn one reactor (O3).

Figure A2: Example of a UMM message


Unavailability of electricity facilities : Production
Ringhals block 4

Published	Event Start	Event Stop	Duration	Type of Unavailability	Reason Code	Reason for the Unavailability	Remarks
2023-12-05T13:09:25	from 2023-12-04T16:30	to 2023-12-05T13:00	20 hours 30 minutes	Unplanned	Failure	Temporary stop of power increase due to extended startup sequence.	New information: Updated "Event stop". After the event stop the plant will be technically available. Ramp up to reach full power is estimated to 8 h.

Production Units

Unit Name	Unit EIC	Area	Installed Capacity	Available Capacity	Unavailable Capacity	Fuel Type	Power Feed-In	From	To
Ringhals block 4	46WPU0000000014Y	SE3	1130 MW	540 MW	590 MW	Nuclear		2023-12-04T16:30	2023-12-05T13:00

Market Participants

Publisher
Ringhals AB

Market Participants
Vattenfall AB (ACER: A0001247V.SE)
Sydkraft Nuclear Power AB (ACER: A00090512.SE)

Related Messages

2023-12-05T13:09 (currently viewing)
2023-12-05T05:49
2023-12-04T16:26

Messages from the same station(s)

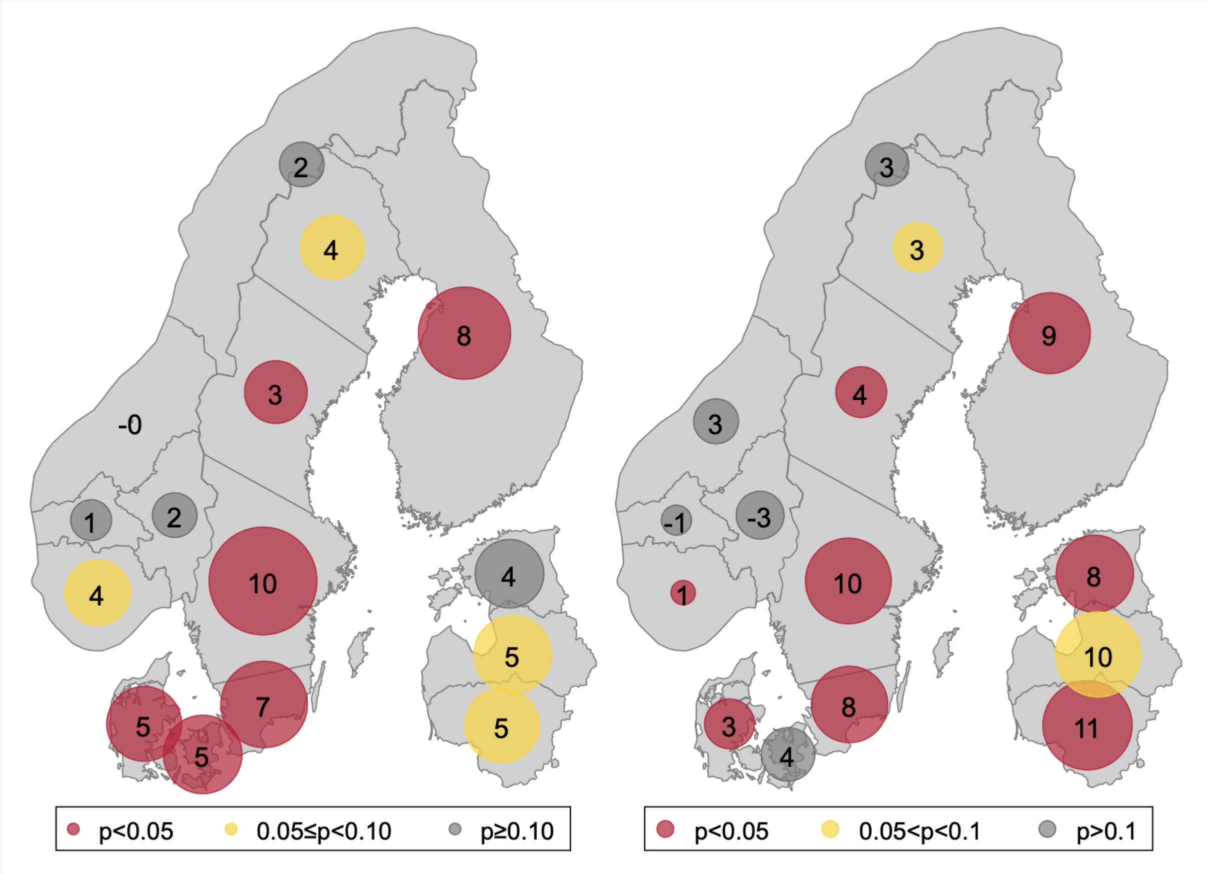
Unplanned, Failure: 2025-09-19T06:08
from 2025-09-18T22:30 to 2025-09-19T05:44
Planned, Foreseen maintenance: 2025-09-17T10:43
from 2025-08-03T03:00 to 2025-09-17T10:37
Planned, Foreseen maintenance: 2025-06-23T15:11
from 2028-08-16T00:00 to 2028-09-20T23:59
Planned, Foreseen maintenance: 2025-06-23T15:08
from 2027-08-04T00:00 to 2027-09-22T23:59
Planned, Foreseen maintenance: 2025-06-23T15:05
from 2026-09-02T00:00 to 2026-10-15T23:59

Acer Message Ids

EUIMSG-BFU0U3Q0C2Y54Z0LBQ_003

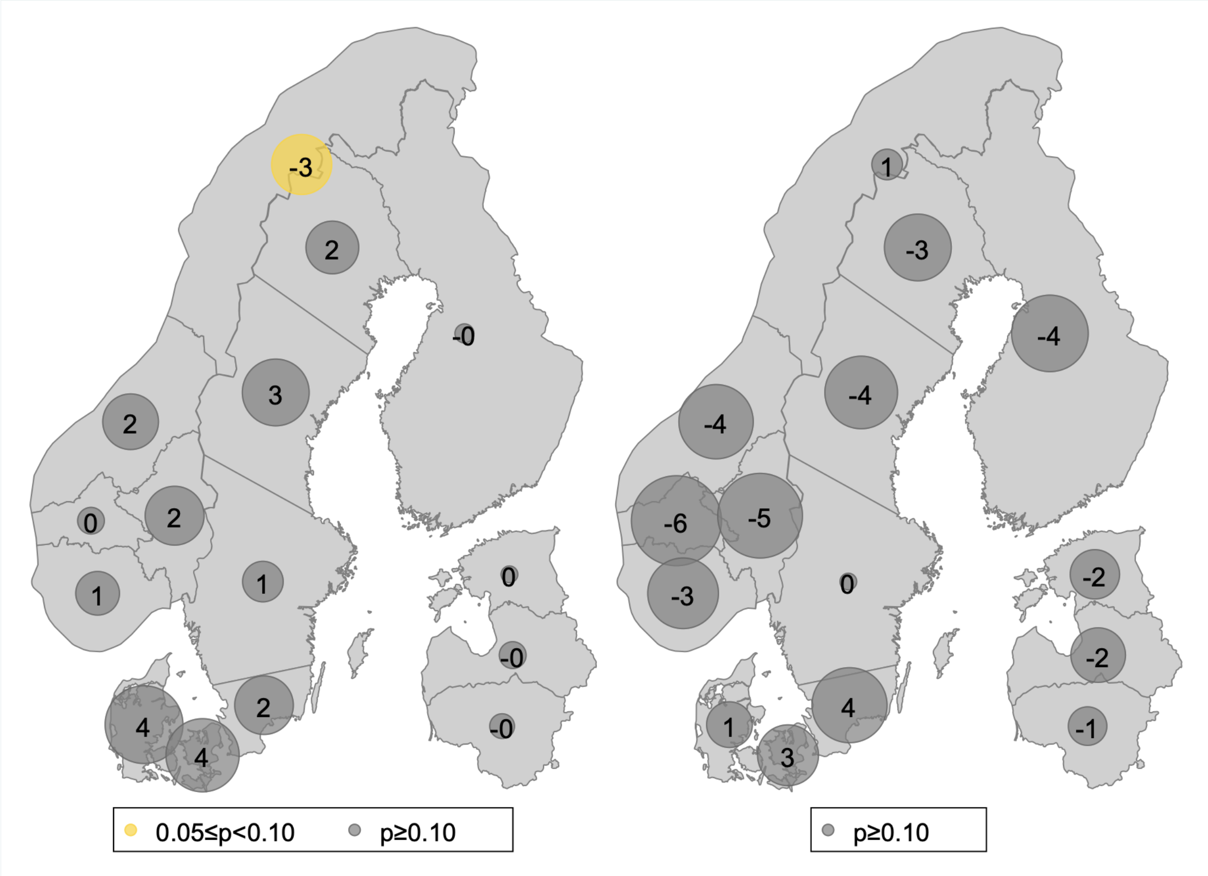
Note: Screenshot from the ENTSO-E Transparency Platform showing an unplanned outage at Ringhals. The message specifies the affected unit, installed and unavailable capacity, event type (unplanned), reason (failure), and the start and expected end times of the outage.

Figure A3: Map of price effects excluding 2022: full sample (left) and restricted sample (right)



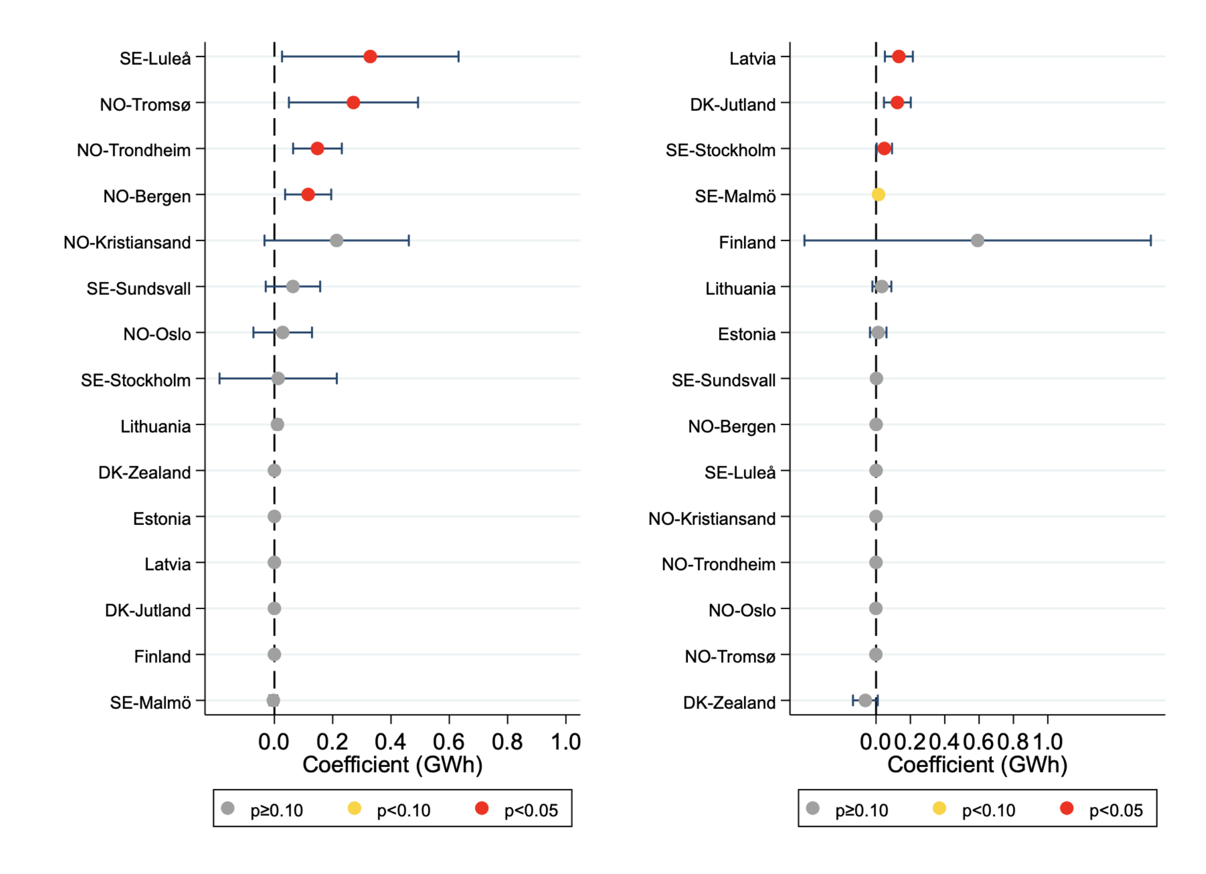
Note: Coefficient estimates from equation (1) with day-ahead price as the dependent variable. Left panel: full sample. Right panel: restricted to hours when prices are predicted to equal SE-Stockholm. Circle size proportional to coefficient magnitude. Colors indicate significance level: red ($p < 0.05$), yellow ($p < 0.10$), gray ($p \geq 0.10$).

Figure A4: Placebo test: price effects with shifted outage timing



Note: Coefficient estimates from equation (1) with day-ahead price as the dependent variable. Left panel: outages shifted one week earlier. Right panel: outages shifted one week later. Circle size proportional to coefficient magnitude. Colors indicate significance level: yellow ($p < 0.10$), gray ($p \geq 0.10$).

Figure A5: Supply response by bidding zone, restricted sample: hydropower (left) and thermal (right)



Note: Coefficient estimates from equation (1) with zone production as the dependent variable. Sample restricted to hours when prices are predicted to equal SE-Stockholm. Zones ordered by significance level, then by coefficient magnitude within each group. Bars indicate 95 percent confidence intervals. Standard errors clustered at the month level.