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Market Power and Joint Ownership: Evidence from Nuclear Plants in Sweden

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Abstract

This paper presents an empirical test of the anticompetitive effects of joint ownership by examining the operation of three nuclear plants in Sweden. Since maintenance is the main conduit explaining variation in output, I formulate a model of optimal maintenance allocation given three behavioral assumptions: i) maximal collusion, where all owners' profits on both nuclear and other output are jointly maximized; ii) Cournot competition, where the majority owners' profits on both nuclear and other output are maximized; and iii) a divested solution, where all owners' profits on nuclear output are maximized, but no weight is given to non-nuclear output. The behavior that fits the data best is a "hybrid" model where maximal collusion is only achieved during periods of the year when regulatory oversight is less strict. During the remainder of the year, data is instead most consistent with the divested solution.

JEL-Classification: L13, L22, L94, D22, D43, D44

Keywords: Joint ownership, electricity wholesale market, nuclear, maintenance, collusion, regulatory threat.

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1 Introduction

Joint ownerships are common in many markets. They may take many forms, such as joint ventures, partial mergers and acquisitions, or joint ownership of production plants.[1] In electricity supply industries, joint ownership of generation facilities is common. In the Nordic market, Amundsen and Bergman (2002) find that the increased wave of mergers and partial acquisitions that took place during the late 1990s may have affected the unilateral incentives of the remaining suppliers to exercise unilateral market power.

In this study, I explore the impact of joint ownership of three Swedish nuclear plants in the Nordic market. In 2001, these plants were jointly owned by three large firms, although each plant had a majority owner. To motivate my modeling exercise, I use monthly aggregate data on nuclear output from 1990 to 2014 to demonstrate that nuclear output shifted away from the winter season after the introduction of joint ownership. In the Nordic region, electricity demand and prices peak during the winter implying that price-taking firms would produce as much output as possible during this season. At the same time, the ability to influence the price is also greater during the winter season, which suggests that joint ownership could have led to the shift of nuclear production away from the winter season. I identify this shift using a difference-in-differences (DiD) estimator, where Finnish nuclear plants serve as the control group.

Next, I analyze a set of hourly data on plant-level nuclear output, outage data, and aggregate bidding curves from the Nordic day-ahead market *Elspot* from 2011-2013 to understand the factors that led to this shift in nuclear production away from the winter season. I begin by examining a data set on publicly available information about nuclear outages, and identify planned maintenance as the primary reason for the reductions in output, while failures only account for a minor share of the reductions. I find that the slope of the hourly residual demand function facing the nuclear plants is a predictor of the magnitude of maintenance outages, but it does not predict the magnitude of failure outages. Specifically, a higher quantity of maintenance outages is associated with a steeper slope of the residual demand curve.

Based on these facts about nuclear plant operating behavior, I formulate a more comprehensive model of firm behavior and simulate optimal nuclear output given three behavioral assumptions: i) maximal collusion, where all owners' profits on both nuclear and other output are jointly maximized; ii) Cournot competition, where the majority owners' profits on both nuclear and other output are maximized given the actions of the competitors; and iii) a divested solution, where all owners' joint profits on nuclear output are maximized, but no weight is given to non-nuclear output. I find that maximal collusion is associated with 20 percent higher prices, on average, than the divested solution, while nuclear capacity utilization is 18 percent lower. The corresponding figures associated with Cournot competition lie in between the two other models.

[1] Markets in which joint ownerships have been studied include the automobile sectors in the U.S. and Japan (Alley, 1997), the U.S. airline industry Azar et al. (2018), the U.S. cellphone industry (Parker and Röller, 1997), U.S. offshore oil tracts (Hendricks and Porter, 1992), and the Dutch and US banking sectors (Dietzenbacher et al., 2000; Azar et al., 2016)

To evaluate model fit, I regress observed output on simulated output and compare the R^2. I find that maximal collusion is only achieved during the summer period when prices are lower and regulatory oversight is less strict. During the remainder of the year, the divested solution matches data best. I interpret this finding as evidence that intensified regulatory oversight and general public awareness of the nuclear owners' activities during the winter leads to relatively more competitive behavior (the regulatory environment is discussed in Section 3.3 below). This result is robust to a range of parameter values on nuclear marginal cost, markups on non-nuclear output, forward contracting volumes, and market shares on non-nuclear output.

Because it is impossible to determine the level of maintenance needed to adhere the legal nuclear safety standards, I also simulate output under a simplified dynamic extension of the model where output is only allowed to shift intertemporally between consecutive weeks, while keeping mean output constant at the observed levels. The hybrid model that assumes a behavior corresponding to the divested solution during the winter and maximal collusion during the summer performs best in terms of model fit also under this constraint.

2 Related literature

Simulation exercises of unilateral market power in electricity markets are frequent. A well-known example is Borenstein et al. (2002), who compute a competitive benchmark price in the Californian wholesale market using engineering estimates of marginal costs. This price is then compared to the observed market price during the first years of deregulation. In another study of the Californian market conducted prior to deregulation, Borenstein and Bushnell (1999) use similar engineering data to assess the potential for market power. They compute a static Cournot equilibrium using an iterative algorithm very similar to the one used in Section 6.

Another closely related simulation exercise is Bushnell (2003). He solves the n-firm Cournot equilibrium conditions for a market where firms own both hydro and thermal plants. Firms then decide on the level of thermal output as well as the intertemporal allocation of hydro output, given that the total water usage across periods is constrained by the content of the reservoir. Using data from the western US, the model is implemented as a mixed linear complementarity problem. Bushnell also notes that thermal generators in fact face a similar dynamic problem when deciding on the intertemporal allocation of maintenance, although his model does not explicitly account for this. In Section 6.1, I build on this insight when solving for the optimal scheduling of nuclear maintenance, although in a simplified two-period duopoly setting.

The simulation studies discussed above do not explicitly model the use of outages as a means to exercise market power, but instead account for the possibility that forced outages may inflate the real price by adjusting the simulated output using unit-specific outage rates. An econometric study that explicitly examines the use of outages as a means to exercise market power is Wolak and Patrick (2001), finding that the strategic timing of scheduled outages by baseload generation contributed to increased profits in the U.K.

wholesale electricity market. Just as in the present context, firms using this strategy also owned other generation units with higher marginal costs. However, to the best of my knowledge the present study is unique in distinguishing between the strategic use of outages declared as failures versus maintenance.

The approach to measuring the ability and incentive to exercise unilateral market power using residual demand functions employed in Section 5 was introduced by Wolak (2003) and McRae and Wolak (2014), studying the wholesale markets in Australia and New Zealand, respectively.

Another strand of literature relates to econometric modeling of joint ownerships. This literature is relatively sparse, and often relies on a comparatively parameterized framework following the work of Bresnahan (1982). In a typical setup, the goal is to estimate a "conduct parameter" between zero and one, where zero corresponds to perfect competition, $\frac{1}{n}$ corresponds to a symmetric n-firm Cournot equilibrium, and one corresponds to joint profit maximization. The conduct parameter approach has been criticized for being a poor predictor of market power, especially in dynamic settings (Tirole, 1988; Corts, 1999). An empirical example is given by Kim and Knittel (2006). Using detailed engineering data on marginal costs from the restructured Californian electricity market, they start by computing actual price-cost margins. They find that the price-cost margins implied by the conduct parameter approach usually do not reflect actual price-cost margins, since the estimated margins are highly dependent on assumptions about the functional form of the residual demand functions facing strategic firms. For a comprehensive review of empirical studies on the anticompetitive effects of joint ownerships, see Schmalz (2018).

A number of studies examine market power in the Nordic electricity market. Lundin and Tangerås (2019) apply a model of Cournot competition to the Nordic day-ahead market during 2011-2013 using similar data as in the present study, concluding that the average price-cost margin was around four percent. Hjalmarsson (2000) estimates a dynamic extension of the Bresnahan-Lau model using data from 1996-1999, concluding that the hypothesis of perfect competition cannot be rejected. Kauppi and Liski (2008) construct a simulation model of hydro production from 2000-2005, showing that a model where one strategic producer controls 30 percent of the hydro capacity fits data better than a competitive benchmark. Damsgaard (2007) presents another simulation model that is tested on data from 2002-2006, without finding any conclusive evidence of market power other than within very limited periods. Mauritzen and Tangerås (2018) study the relationship between the day-ahead price and the intraday price, rejecting the hypothesis of perfect competition. Finally, Fogelberg and Lazarczyk (2014) study the use of capacity withholding through "voluntary" production failures to exert market power in the Nordic market in 2011-2012. They find indications of strategic withholding of fossil plants, but not nuclear or hydro plants. However, their analysis relies on a different set of identifying assumptions than the analysis in the present study, as they do not make use of bidding or production data.

A few studies examine the relationship between economic incentives and nuclear plant performance. In terms of strategic investments in nuclear capacity, Fridolfsson and Tangerås (2015) develop a theoretical model to demonstrate that incumbent producers' incentives to expand nuclear capacity in the Nordic market could be weak, since that would reduce the profitability of installed capacity. In a related study, Liski and Vehviläinen (2018) show theoretically how joint ownership of Nordic nuclear plants may induce a collusive phase-out that would not take place without joint-ownership. Although I examine the temporary withholding of already existing capacity, my results empirically verify that the concerns discussed in these theoretical papers may be well grounded.

In terms of empirical work on nuclear power capacity utilization, the relationship between operating efficiency and deregulation is studied by Davis and Wolfram (2012). Using U.S. data from 1970-2009, they use a DiD estimator to find that deregulation and consolidation of ownership are associated with a 10 percent increase in operating efficiency. Using cross-sectional data from mainly UK and U.S. plants in 1989, Pollitt (1996) finds some evidence that regulated, privately owned nuclear plants are more efficient than publicly owned plants. None of these empirical papers examine the possibility of nuclear capacity withholding as a means to exercise market power.

Within the theoretical literature there are several studies on the competitive effects of joint ownerships, disentangling at least two channels by which joint ownership has anti-competitive effects: One is through promoting collusion, in that joint ownership facilitates information- and profit sharing. See Green (1980) for an analysis of how information exchange can induce collusion, and Malueg (1992) for an analysis of how the interconnection of profits induced by joint ownership may facilitate collusion. The other is through a reduction in the unilateral incentives to act competitively (Reynolds and Snapp, 1986). The reason for this is purely mechanical, in the sense that the linking of profits reduces each firm's incentive to compete. In their setting, firms own shares in each others' production plants, with one owner being the designated "controller" who decides the level of output. A key result is that in a symmetric n-firm Cournot equilibrium, total output will be identical to the monopoly output if every firm controls at least $\frac{1}{n}$ of the shares in each of the other firms. Following the logic of Reynolds and Snapp, the unilaterally profit maximizing equilibrium in the present setup is therefore likely to be more competitive than the monopoly outcome, although a direct analogy to their model cannot be made since the firms examined in the current study also control a set of plants that are not jointly owned.

3 Institutional background and data

3.1 The Nordic power exchange, Nord Pool

The Nordic electricity markets were deregulated during the 1990s, creating a common power exchange, *Nord Pool*, for Norway, Denmark, Sweden and Finland. It now also includes Estonia, Latvia and Lithuania. The main auction for physical energy is the day-ahead market, *Elspot*, in which about 80 percent of all electricity produced in the region is sold. It has the format of a uniform price auction, and each day at noon market participants submit their bids to the auctioneer for delivery the next day. There is a separate auction each hour. Offer curves are piecewise linear upward sloping curves and demand curves are piecewise linear downward sloping curves with up to 62 price steps per participant. During the sample period, the price ceiling was 2000 EUR/MWh (In 2015, the price cap was raised to 3000 EUR/MWh). The auctioneer sums the bids to arrive at the *system* supply and demand functions, and clears the market where the system supply function meets the system demand function using linear interpolation.[2] This price is called the Elspot system price. Figure 1 shows an example of the system supply and demand curves.

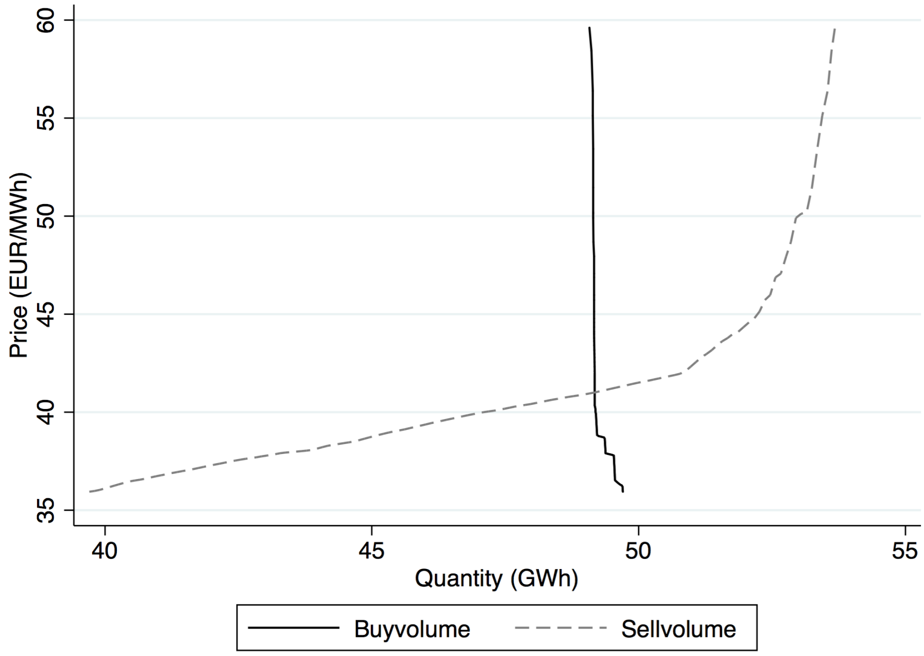
In the absence of transmission constraints, all participants face the system price. When there are bottlenecks in transmission, the market may be divided into 15 different price zones depending on where the bottlenecks occur. The geographical borders of the price zones are illustrated in Figure A3. In zonal markets, bids are only tied to a specific zone, instead of a specific generation unit. This means that producers are free to meet their day-ahead obligations using any combination of their generation units located within that zone. Therefore, bidding data can only inform the data analyst of the quantity of energy supplied at different prices, but not the specific generation units that will supply that energy. All Swedish nuclear plants are located within the same price zone (SE3) which follows the system price closely (the correlation between the system price and the price in SE3 is 0.96). Since I only have data on system level bidding curves, I can only replicate the system price and not prices in individual zones. Therefore, I use the system price as a proxy for the price received by the nuclear plant owners.

The nuclear owners sell all their output on the day-ahead market, and any obligations to deliver electricity through forward contracts are settled financially. The system price is the reference price for the main financial products. Thus, if a producer has sold a forward contract of 1 MWh for a price of 10 EUR and the day-ahead price is realized at 9 EUR/MWh, the producer receives 1 EUR in cash from the buyer of the contract. Forward obligations have a positive effect on the unilateral incentives to behave competitively in the day-ahead market, since increasing the day-ahead price will only increase the compensation for electricity that is not already forward contracted. Vertical integration, i.e., when a firm is active in both the wholesale and retail markets, has a similar effect when retail prices are regulated. See Wolak (2000) for a study of the competitive effects of forward contracting in the Australian wholesale market, and Bushnell et al. (2008) for a study of the competitive effects of vertical integration in three electricity markets in the U.S. The buyers of these contracts are usually electricity retailers or large industrial consumers.

Retail prices are unregulated in the Nordic region and are often set as a markup over the mean day-ahead price for a certain period, although a smaller fraction of residential customers still had fixed price contracts during the sample period. Hence, price increases in the spot market are largely passed on directly to consumers. A likely reason for the

[2] In addition to regular bids, participants also have the possibility to submit so-called block bids. A block bid can be distinguished from a regular bid by two characteristics. First, a block bid refers to more than one hour, and second, a bid is either accepted or not accepted as a whole. On average, five and one percent of the accepted sell- and buy volumes in the data, respectively, comes from block bids. At present, I only have data on the volume of accepted block bids, and not at which price they were bid into the market. Conveniently, both net exports and accepted block bids are entered as zero price bids by the auctioneer when computing the system price, enabling me to exactly replicate this price. On average, 6 percent of the traded volume comes from net exports.

Figure 1: System supply and demand



Note: System supply and demand functions on the Nordic day-ahead market Elspot during 2-3 pm, January 19, 2013. Source: Nord Pool.

small share of fixed price contracts is that they are almost always more expensive for a consumer with a representative load curve (Swedish Consumer Energy Markets Bureau, 2020).

Nordic production capacities are presented in Table 1. The Nordic market is hydro dominated, accounting for 49 percent of the installed capacity. Thermal non-nuclear capacity accounts for 30 percent, followed by Swedish and Finnish nuclear (9 and 3 percent respectively). Wind power accounted for 8 percent of installed capacity during the sample period, but has continued to expand during the last decade.

There are five nuclear plants in the Nordic region. Three are located in Sweden and two in Finland. The ownership structure of the Swedish plants is presented in the first part of Table 2. Vattenfall, Fortum, and E.ON jointly own the Swedish plants according to the ownership structure presented in the first part of the table. E.ON is the only firm that owns shares in all three plants. E.ON is also the majority owner in Oskarshamn, and Vattenfall is the majority owner in Ringhals and Forsmark. Fortum owns shares in both Oskarshamn and Ringhals. With respect to total capacity, Vattenfall is the largest owner with a combined ownership share of 51 percent, followed by E.ON (30 percent) and Fortum (18 percent).

The second part of Table 2 lists installed capacities of non-nuclear technologies. Also here, Vattenfall controls the greatest share of the capacity. Hydropower constitutes the major share of non-nuclear capacity for each firm. Each firm also owns a number of fossil-based thermal generation plants as well as a number of combined heat and power (CHP)

Table 1: Production capacity in the Nordic region.

Technology	Capacity share (%)
Hydro	49
Thermal (non-nuclear)	30
Swedish nuclear	9
Finnish nuclear	3
Wind	8

Note: Installed capacity by technology for the Nordic market (2011-2013 average). Source: Nordreg (2011, 2012, 2013).

plants. The CHP plants are used for district heating and generate electricity as a by-product. Vattenfall and Fortum also own a number of wind farms (in the years following the sample period, E.ON also invested in wind power and the other firms expanded their wind capacities).

The third part of the table lists the nuclear owners' market shares on physical output in the Nordic region, displaying a combined market share of 43 percent. As noted above, 80 percent of all electricity produced in the region is sold in the day-ahead market, while the nuclear owners sell all their physical energy here. Therefore, their market shares on the day-ahead market is even larger, which is presented in the last part of the table (these figures are computed by dividing the corresponding physical market shares by 0.8). It is notable that the three firms enjoy a combined market share of more than half of the day-ahead market, at 54 percent.

3.2 Data

The data presented in Table 2 in the section above has been collected using several sources. The first and second part of the table uses information from the annual reports of each firm. The third part uses data on physical market shares published yearly by the Nordic Energy Regulators Nordreg (2011, 2012, 2013). The figures published in these reports refer to market shares including nuclear output, so I use data on total Nordic output (from the same reports) and data on nuclear output (compiled specifically for this study by the Swedish TSO *Svenska Kraftnät*) to compute the implied nuclear and non-nuclear market shares.

In the analyses below, I use several data sources. In Section 4 I examine monthly nuclear output in Sweden and Finland during 1990-2013. These data are available for download from Statistics Sweden and Statistics Finland respectively (Statistics Sweden, 2015; Statistics Finland, 2015). As control variables, I use hydro inflow to the Nordic reservoirs (downloaded from www.nordpoolgroup.com) and temperature (SMHI, 2016).

In Section 5, examining the relationship between nuclear outages and the ability to exert market power using data from 2011-2013, I use the "Urgent Market Messages" database (downloaded from the Nordpool FTP-server) to compute the hourly size of planned maintenance and unplanned nuclear failures. All outages have to be reported to Nord Pool.

Table 2: Installed capacity and Nordic market shares by nuclear owner and technology

	All nuclear owners	Vattenfall	E.ON	Fortum
Installed nuclear capacity	**Joint capacity (GWe)**	**Firm ownership share (%)**		
Ringhals	3.7	70	30	0
Forsmark	3.1	66	10	22
Oskarshamn	2.3	0	55	45
All plants	9.1	51	30	18
Installed non-nuclear capacity	**Joint capacity (GWe)**	**Firm capacity (GWe)**		
Hydro	14.7	8.3	1.8	4.6
Thermal (fossil)	6.4	2.5	2.1	1.8
Combined heat and power	1.5	0.2	0.2	1.1
Wind	0.8	0.7	0	0.1
All plants	23.4	11.7	4.1	7.6
Market share on physical Nordic output	**Joint market share (%)**	**Firm market share (%)**		
Nuclear	16	8	5	3
Non-nuclear	27	14	3	10
All technologies	43	22	8	13
Market share on day-ahead market	**Joint market share (%)**	**Firm market share (%)**		
Nuclear	20	10	6	4
Non-nuclear	34	17	4	13
All technologies	54	28	10	16

Note: First part: Current ownership structure of Swedish nuclear plants. Two percent of Forsmark is controlled by the municipally owned power company Skellefteå Kraft (not present in the table). Second part: Installed non-nuclear capacity by technology and firm during 2011-2013. Third part: Market shares on physical output in the Nordic region during 2011-2013, by technology and firm. Fourth part: Market shares on day-ahead market by firm. Source: Annual reports of each firm 2011-2013 (first and second part). Nordreg and SvK (third part). Author's own computations (fourth part).

These messages are immediately made available to the public. Figure A4 shows an example of such a message. The intention of the database is to prevent participants to arbitrage on inside information, and to facilitate production planning. A similar information system is currently being implemented in all European electricity markets through a cooperation among the European energy regulators (ACER, 2015). The database is accessible to all market participants without delay. A message should preferably be posted simultaneously with, but no later than 60 minutes after, the decision for a scheduled maintenance has been made, or at the start-time for a failure. The message has to include the estimated start- and stop time of the outage, size of the outage, fuel type, as well as an identification of the plant including the owner. Information contained in a message may be updated by sending so-called follow-up messages. For example, a firm may not be able to provide accurate information about the length of a failure at the time it occurs, or may reschedule previously announced maintenance.

In total there are 467 unique events concerning the nuclear plants reported during the sample period, with an average of 4.5 messages per event. 90 percent of the outages (measured in GWh) can be attributed to maintenance. Excluding follow-ups and failures, half of the events had been reported to the database prior to two weeks before the beginning of the outage. Since Swedish nuclear plants are constructed to operate at full available capacity, in theory it should be possible to replicate the output of each reactor just by using information from the Urgent Market Messages. It happens that output does not correspond exactly with the information provided in the messages. Some messages only contain approximations of the length of an outage. Other messages contain information about coastdowns (i.e. when a reactor gradually decreases production until the fuel in the core is depleted), and these messages do not contain information about output at each specific point in time. Still, the information contained in the messages can be used to replicate output very well, with an average absolute deviation from observed output of less than 5 percent (see Figure A5 and A6).

When computing the slope of the residual demand curve facing the nuclear plants, I use system supply and demand functions (downloaded from the Nord Pool FTP-server), and hourly data on nuclear output. Firm level bid data is not available. In Section 5.1 I explain in detail how I compute the slope. As control variables I use Swedish wind power production, the Nordic demand forecast, and the system price (downloaded from the Nordpool FTP server), as well as hydro inflow and temperature.

Table 3 presents descriptive statistics, starting with figures describing nuclear capacity utilization. Of all Swedish plants, Oskarshamn had the lowest capacity factor, followed by Ringhals and Forsmark. A closer look at the capacity factors for the aggregate output reveals that output may be fairly volatile also within a single month, which is illustrated in Figure 2. As a comparison, the corresponding trend for Finnish plants are depicted in the same figure, revealing that Finnish plants operate at full capacity more often, except for limited periods of refueling during the summer season. Total capacity availability net of outages reported as maintenance is 83 percent, and the corresponding figure for failures is 95 percent, demonstrating that the majority of the output variation is due to maintenance.

The mean system clearing price is 39 EUR/MWh. As depicted in Figure 1, the entire demand function is usually highly inelastic except at very low prices. The supply elasticity varies more. Nuclear and hydro production constitute base load, and are usually supplied at low prices. As demand increases, more thermal production is dispatched and the supply curve becomes steeper. As a result, in peak hours (8 am to 8 pm) the supply elasticity is generally low. The average price during a peak hour is 30 percent higher than the average price during a baseload hour, which is comparable to the price difference between the winter- and summer period. The mean clearing quantity is 36 GWh, which is 20 percent lower than the demand forecast. This is since 80 percent electricity consumed is traded through bilateral contracts outside the day-ahead market. Hydro reservoir inflow, measured in GWh of potential electricity production, is about half of the demand forecast, consistent with the fact that hydro production constitutes about half of the production in the market. The temperature variable measures the mean temperature in price zone SE3, i.e., where the nuclear plants are located. Geographically, this area is also centrally located in the market. The last control variable, Swedish wind production, was on average 0.89 GWh.

As seen in the last part of the table, Swedish capacity factors were about 13 percent lower than the corresponding Finnish figures during the sample period of the DiD analysis. While Finnish capacity utilization has been around 90 percent throughout the sample period, the Swedish plants only reached 90 percent during one year, in 2004.

In Section 6, I also use two additional unobserved variables that have to be approximated: nuclear marginal cost and forward obligations.

Nuclear marginal cost I approximate marginal cost by the mean accounted fuel cost for all plants during the sample period, compiled from the annual reports of each plant (OKG AB, 2014; Forsmark, 2014; Ringhals, 2014). This cost amounts to EUR 5/MWh, corresponding to 13 percent of the mean day-ahead price (fuel costs differ only trivially across plants and years). The fuel cost depends both on the direct cost of fuel, which was on average EUR 3.5/MWh, and a mandatory depository fee based on the amount of electricity produced, which was EUR 1.5/MWh. The nuclear producers also pay a nuclear tax based on the installed capacity of each reactor. However, a reactor is only exempted from the tax if it remains inactive for more than three months. Therefore this tax should not be considered as a variable cost. Further, I do not consider the cost of labor or capital as variable costs, since these costs are in principle invariant to the amount of maintenance performed.

Forward obligations Although firms do not report their forward positions for every point in time, the financial statements of both Vattenfall and Fortum contain information about the expected hedging ratio (i.e. the ratio between the volume of hedged electricity and expected physical spot market sales) for the upcoming year. For E.ON, the corresponding information is provided in yearly investor presentations released together with the annual reports (Vattenfall, 2013; Fortum, 2013; E.ON, 2014). The hedged electricity consists mainly of financial futures, and a small share of fixed-price retail obligations due to vertical integration. Hedging ratios differ only slightly across years within firm, and are about 70 percent for both Vattenfall and Fortum, and 80 percent for E.ON.

I approximate the volume of forward obligations using the following steps: First, I multiply

Table 3: Summary statistics

Variable	Mean	St.dev	Min	Max
Main analysis				
Capacity factor in Oskarshamn	66.07	24.38	0.00	100
Capacity factor in Ringhals	72.02	25.46	0.00	100
Capacity factor in Forsmark	90.42	17.76	31.43	100
Mean capacity factor	76.12	15.32	35.50	100
Total capacity availability net of maintenance	83.24	14.49	41.05	100
Total capacity availability net of failures	94.55	5.93	67.02	100
Total nuclear production	6.98	1.41	3.25	9.16
System clearing price	38.78	14.28	1.38	224.97
System clearing quantity	35.94	7.27	19.89	58.16
Demand forecast	43.77	8.92	25.81	68.99
Reservoir inflow	23.99	17.93	2.48	98.54
Temperature	7.58	8.39	-21.6	27.9
Swedish wind production	.89	.60	.02	3.54
DiD analysis				
Swedish capacity factor	76.98	16.56	28.66	100
Finnish capacity factor	89.24	9.82	57.52	100

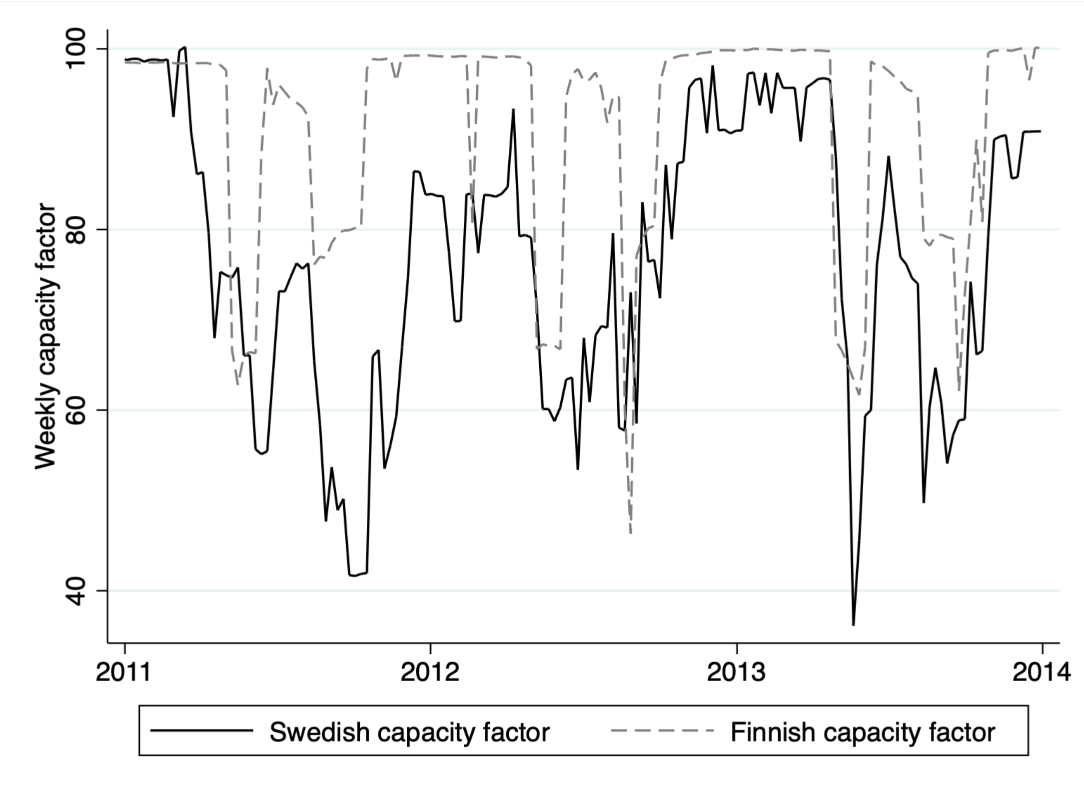
Note: Capacity factors and capacity availability in percent. Nuclear production, clearing quantity, demand forecast, reservoir inflow, and wind output in GWh/h. Clearing price in EUR/MWh. Temperature in Celsius, and wind speed in m/s. All variables in the main analysis are hourly except for reservoir inflow, which is weekly. In the DiD analysis, observations are by month.

the observed yearly cleared day-ahead volume with each firm's market share on the day-ahead market (these market shares are presented in Table 2). I then again multiply this volume with the self-reported hedging ratio of each firm for the upcoming year, as stated in the financial statement/investor presentation for the previous year. This gives me an estimate of the total yearly volume of forward obligations. In the robustness section I also simulate output for a range of parameter values reflecting hedging ratios down to zero percent. I then need to allocate the contracts within each year. The smallest contracting time for which there is a relatively liquid forward market is weekly, so I let the volume of forward contracts be constant within each week. I then assume that forward volumes are directly proportional to the observed cleared day-ahead volume of that week. That is, if the cleared day-ahead volume during one week amounts to two percent of the corresponding yearly figure, I allocate two percent of that firm's yearly forward obligations to that week. This is certainly a simplification, and the actual intertemporal allocation of forward contracts will differ from this approximation.

3.3 Nuclear power in Sweden

The ownership structure of the Swedish nuclear plants was formed around the turn of the century. In 1999, the reactor Barsebäck 1 (with a capacity of 0.6 GW) was permanently shut down as a first step to phase out the Swedish reactors. In 2005, the remaining reactor Barsebäck 2 (with a capacity of 0.6 GW) was also shut down. Since Barsebäck was fully

Figure 2: Swedish and Finnish nuclear capacity factors 2011-2013



Note: Aggregate weekly nuclear capacity factors and Finland during 2011-2013.

owned by the Swedish firm Sydkraft, Sydkraft acquired shares in Ringhals from Vattenfall as a compensation for the shut down, in an agreement between Sydkraft, Vattenfall, and the Swedish government. In 2001, Sydkraft acquired shares in Forsmark from Vattenfall in exchange for shares in the German energy firm HEW. Shortly afterwards, E.ON became the majority shareholder in Sydkraft. In 2000, Fortum entered the market by acquiring the Swedish firm Stora Kraft, thereby gaining ownership in both Forsmark and Oskarshamn.[3] For further details about these M&As, see Energy Markets Inspectorate (2006).

Even though Vattenfall is a state-owned Swedish firm, bonuses of executives depend on value creation rather than social welfare. More specifically, value creation is defined as return on capital employed minus the cost of capital (Vattenfall, 2013). Thus, Vattenfall should behave as a profit maximizer rather than a social planner.

The nuclear plants are organized as limited liability companies, and the majority owner in each plant has the operational responsibility for that plant (Energy Markets Inspectorate, 2010). Each owner of a plant is represented on the board of that plant. Within these

[3]Ringhals has four reactors. The first reactor began operation in 1975, and is a pressurized water reactor. The second reactor began operation in 1976, and is a boiling water reactor. The other reactors began operation 1981 and 1983 and are both pressurized water reactors. Forsmark has three boiling water reactors that began operation in 1980, 1981, and 1985 respectively. Oskarshamn has three reactors, all of which are boiling water reactors. The reactors began operation in 1972, 1974 and 1985. For further information about the technical characteristics of the plants, see Swedish Radiation Safety Authority (2014).

boards, the practice of interlocking directorates is common, meaning that board members are shared among plants. In addition, several of the board members also serve on the board of one of the owner's hydro or wind production divisions (Swedish Competition Authority, 2009).

After some years of low wholesale prices, in 2000 nuclear production suddenly dropped simultaneously in all of the plants. Attention was brought to Vattenfall. In a radio interview (Radio Sweden, 2006), the head of production planning at Vattenfall later claimed that:

> "Sometimes we reduced [nuclear] production when prices were above the variable cost...with the result that prices increased...but we never did it in agreement with the other co-owners."

Due to these events, the Swedish Competition Authority investigated suspicions of coordinated behavior, finding that up until 2002 all production decisions were planned at meetings among the owners in a way that was illegal. However, that practice had been interrupted by the time of the investigation, and the case was closed. Since 2002 each separate owner instead has the right to the available capacity in each plant net of maintenance and other outages, proportional to its ownership share. Each owner then independently requests from the plant operation manager how much of that capacity it would like to use for production (Nordic Competition Authorities, 2007). Beginning in 2002, owners have, with very few exceptions, requested that all available capacity should be used. Instead, maintenance outages have become more frequent. Specifically, it has become more common to schedule maintenance outages during the winter season (November-March) instead of during the summer (Swedish Competition Authority, 2009).

Although the Swedish competition authority has repeatedly pushed for a termination of the ownership, Swedish competition law is restrictive regarding the possibility to force divestitures of already existing ownership structures. Therefore, in 2008 the government initiated negotiations with the firms to voluntarily terminate the joint ownership. The negotiators also retained two leading Nordic nuclear experts to analyze the difference in availability between Swedish and Finnish nuclear reactors. The experts stated that it could not be shown that the Swedish nuclear operated in conflict with applicable competition legislation, and the negotiations were abandoned in 2010 (Agevik and Magnusson, 2010). In response to a number of price spikes during the winter of 2009-2010 due to a combination of cold weather and prolonged periods of nuclear maintenance, the Swedish government instead obliged owners to adopt a "Code of conduct" that explicitly regulates the type of information that can be shared among the owners (Energy Markets Inspectorate, 2010). To further impede the risk of price spikes, owners were later also obliged not to perform maintenance during the winter season (November-March) unless the owners assessed it to be necessary for safety reasons.

Hence, the threat of even stricter regulation in the future should incentivize owners to refrain from exerting all their available market power during the winter period. Empirical evidence that firms exercise less market power during periods of intensified regulatory oversight has previously been documented, e.g., in the context of the British electricity market (Wolfram, 1999; Wolak and Patrick, 2001). For a theoretical model of the tradeoff between a monopolist's short term profits and the possibility of future regulation, see Glazer and McMillan (1992).

Media attention and consumer complaints are also more likely to occur during the winter season. To demonstrate that the general public is more alert to nuclear activities during the winter, I use Google Trends to track the seasonal variation in the googling frequency of *kärnkraft* (nuclear power) within Sweden during 2004-2014. These figures reveal that the relative googling frequency of *kärnkraft* is about twice as high during the winter months compared to the summer. Figure A8 depicts this frequency over time, displaying a consistent pattern of higher frequencies during the winter each year.

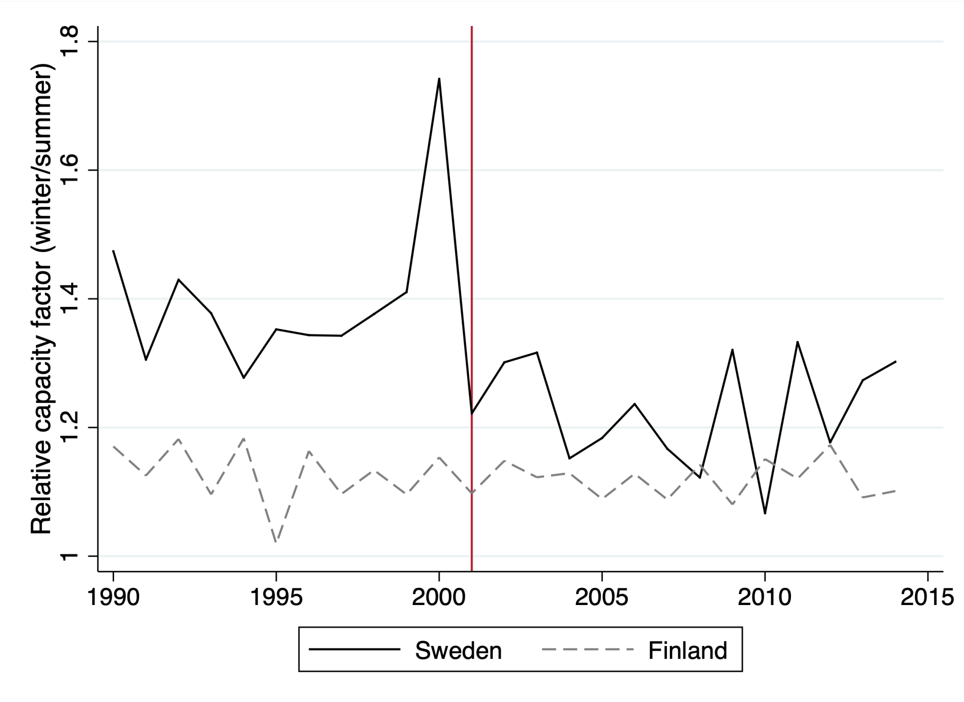
In contrast to many other electricity markets, maintenance plans do not have to be approved by the transmission system operator (TSO) beforehand, and the TSO has thus far never stepped in and demanded maintenance outages to be rescheduled (SvK, 2019). However, under the new EU system operation guidelines, each maintenance outage will have to be approved by the TSO (ENTSO-E, 2017). It should be noted though, that the TSO will only demand rescheduling due to network reliability issues and not market outcomes.

In terms of capacity utilization, Swedish reactors have performed worse than comparable foreign reactors after the deregulation in 1996. Comparing the years before and after Swedish deregulation, the mean capacity factor of foreign plants increased from 73 percent to 87 percent, while the mean Swedish capacity factor remained around 77 percent during both periods.[4]

Except for strategic reasons, another credible explanation for the relative drop in capacity factors is the decision in 1980 (by referendum) to gradually phase out the Swedish nuclear plants, although the only plant that has in fact been shut down is Barsebäck. The decision may have incentivized owners to refrain from large-scale investments that would mitigate the need for frequent maintenance disruptions. There is also a lack of inflow of new nuclear specialists, likely due to the common perception that the nuclear plants will be shut down at some point (SvD, 2009). Therefore, it is important to identify market power not only by examining the absolute level of output, but also its intertemporal allocation. As discussed in the introduction, in the dynamic extension of the model I therefore identify market power exclusively by comparing the intertemporal variation in output across consecutive weeks, while leaving mean output at its observed level.

[4]When comparing historical capacity factors of Swedish and foreign nuclear reactors, I use data from the IAEA Power Reactor Information System (IAEA, 2015) from 1990-2013. Since older reactors tend to have lower capacity factors than newer ones, only foreign reactors constructed before 1975 are included in the sample. All but two of the of the Swedish reactors were constructed after 1974, and those two reactors have been excluded. Also, all plants that have been permanently shut down are excluded. In other words, all Swedish reactors are of the same age or younger than the foreign ones, and should therefore have at least as high capacity factors *ceteris paribus*. The mean construction year of a Swedish reactor in the sample is 1979, compared to 1972 for the foreign reactors.

Figure 3: Share of yearly nuclear output allocated to the winter season



Note: Capacity factors during the winter (November-March) divided by the capacity factors during the summer (April-October) each year during 1990-2014 in Sweden and Finland. The vertical line is at the introduction of the joint ownership (2001).

4 A descriptive DiD analysis

As discussed above, Swedish nuclear output shifted away from the winter season in tandem with the introduction of the joint ownership. To illustrate this shift, Figure 3 depicts the capacity factor during the winter (November-March) divided by the capacity factor during the summer (April-October) each year during 1990-2014. The vertical line (2001) is at the introduction of the joint ownership. The peak in 2000 is due to the event discussed in Section 3.3, when nuclear production suddenly dropped simultaneously in all of the plants (this event took place during the summer season). By comparison, the corresponding trend for Finnish nuclear plants that did not experience a change in the ownership structure remained approximately constant.[5] Since both countries' wholesale markets are interconnected, prices that firms receive after deregulation only differ trivially.

To econometrically demonstrate this shift, I estimate the model:

[5] It is important to note that mean Swedish capacity factors were about the same before and after the ownership change. Otherwise, a reduction in the share of output allocated to the winter season could have been achieved by simply increasing output during the summer season. Another event taking place just before the change in the ownership structure was that a small reactor accounting for about 6 percent of Swedish nuclear capacity was permanently shut down in 1999 (Barsebäck 1). However, even under the assumption that Barsebäck 1 would have produced most of its output during the summer season, the share of output allocated to the winter season would still have been higher during the post-treatment period.

$$nuc_{iym} = \alpha + Sweden_i + Wint_m + Joint_y + \delta D_{iym} + \boldsymbol{\rho}_{iym} + \mathbf{X}_{ym}\boldsymbol{\gamma} + \varepsilon_{iym} \quad (1)$$

Where nuc_{iym} is (the logarithm of) nuclear output in country i in year y during month m, and α is a constant. Trends in Swedish and Finnish output throughout the sample period are depicted in Figure A1 and A2, respectively. $Sweden_i$ is an indicator variable taking the value one for all Swedish observations, $Wint_m$ is a winter season (November - March) fixed effect, and $Joint_y$ is a post-joint ownership fixed effect taking the value one for all observations after 2000. The treatment effect is captured by δ, estimating the effect of the indicator variable D_{iym}, which takes the value one during the winter months of the post-joint ownership period for Swedish nuclear production and zero otherwise. In addition, I include a set of country-year-winter fixed effects. In the baseline regression I include $Winter_m \times Sweden_i$. In some specifications, I also include $Joint \times Sweden$, $Joint \times Winter$, as well as a full set of $Country \times Year$ fixed effects. Finally, $\mathbf{X}_{ym}$ is a matrix of time-varying control variables with its associated coefficient vector $\boldsymbol{\gamma}$. As control variables, I include mean monthly temperature (to proxy for demand), as well as inflow to the hydro reservoirs, measured in GWh of potential output (both variables are log transformed). Both temperature and hydro inflow should have a negative impact on output: higher temperatures shift aggregate demand inwards, and higher inflow shifts residual demand inwards due to higher hydro output.

From Figure 3 it is also clear that the year with the lowest relative winter output was in 2010, i.e., around the time of the intensified regulatory oversight. In the following years, this figure increased somewhat, suggesting that the intensified regulatory oversight may have had a pro-competitive effect.

Results are presented in Table 4. The estimated treatment effect $\hat{\delta}$ ranges between -0.13 and -0.17 and is statistically significant in all specifications, consistent with the hypothesis that the joint ownership rendered possible a change in the operation of the plants. However, the firms may have decided to enter into joint ownership agreements because of how they expected to operate the nuclear units after the joint ownership. Therefore, this result should be interpreted as descriptive evidence rather than as a way to establish causality. The economic interpretation is that Swedish nuclear output decreased by 13 to 17 percent during the winter season of the post-joint ownership period relative to the Finnish plants, conditional on the control variables. In specification (2), the interaction terms $Joint \times Sweden$ and $Joint \times Winter$ are also included as controls, and in column (2) I also include month-of-sample fixed effects. In (3)-(4) I also include a full set of $Country \times Year$ fixed effects. The covariates temperature and hydro inflow included in column (4) both have the expected negative effect on output. Placebo estimates of specification (4) are presented in Figure A7, where the year of treatment varies between 1996-2010. The greatest effects are obtained just around the time of the introduction of the joint ownership (2000-2001).

Table 4: DiD estimates

	(1)	(2)	(3)	(4)	(5)
Treatment effect (δ)	−0.17***	−0.13***	−0.13***	−0.13***	−0.16***
	(0.022)	(0.029)	(0.041)	(0.030)	(0.038)
Joint	0.069***	0.095***	0.11***	0.035***	0.032***
	(0.016)	(0.017)	(0.035)	(0.0045)	(0.0069)
Winter	0.084***	0.085***	−0.0065	0.085***	−0.018
	(0.0049)	(0.0093)	(0.016)	(0.0096)	(0.024)
Sweden	0.82***	0.86***	0.86***	0.60***	0.58***
	(0.025)	(0.041)	(0.058)	(0.0097)	(0.014)
Winter x Sweden	0.25***	0.23***	0.23***	0.23***	0.26***
	(0.015)	(0.022)	(0.031)	(0.023)	(0.033)
Joint x Sweden		−0.071	−0.071	0.16***	0.18***
		(0.049)	(0.070)	(0.012)	(0.016)
Joint x Winter		−0.0024	−0.057**	−0.0024	−0.0018
		(0.010)	(0.020)	(0.011)	(0.016)
Hydro inflow					−0.034***
					(0.011)
Temperature					−0.065**
					(0.026)
Country x Year	No	No	No	Yes	Yes
Month-of-sample	No	No	Yes	No	No
Observations	600	600	600	600	480

* $p < .10$, ** $p < 0.05$, *** $p < 0.01$

Note: Results from the DiD-estimation of eq. (1). Standard errors are clustered by year. Variables are log transformed.

5 A diagnostic test of market power

In this section I examine the relationship between nuclear outages and the nuclear suppliers' ability to exercise market power. Specifically, I examine if nuclear suppliers are jointly more willing to declare more planned outages or failures when the residual demand function facing the nuclear plants is steep, employing a slightly modified version of the methodology outlined by Wolak (2003) and McRae and Wolak (2014).

Ceteris paribus, nuclear owners perform maintenance when the price is low. The aggregate supply function is often convex due to increasing marginal costs. In effect, when the price is low, the residual demand function is often flat around the equilibrium point. Hence, the raw correlation between the size of nuclear outages is not informative about the exercise of market power. To examine the relationship between nuclear outages and the ability to exert market power, I use OLS to estimate the following model:

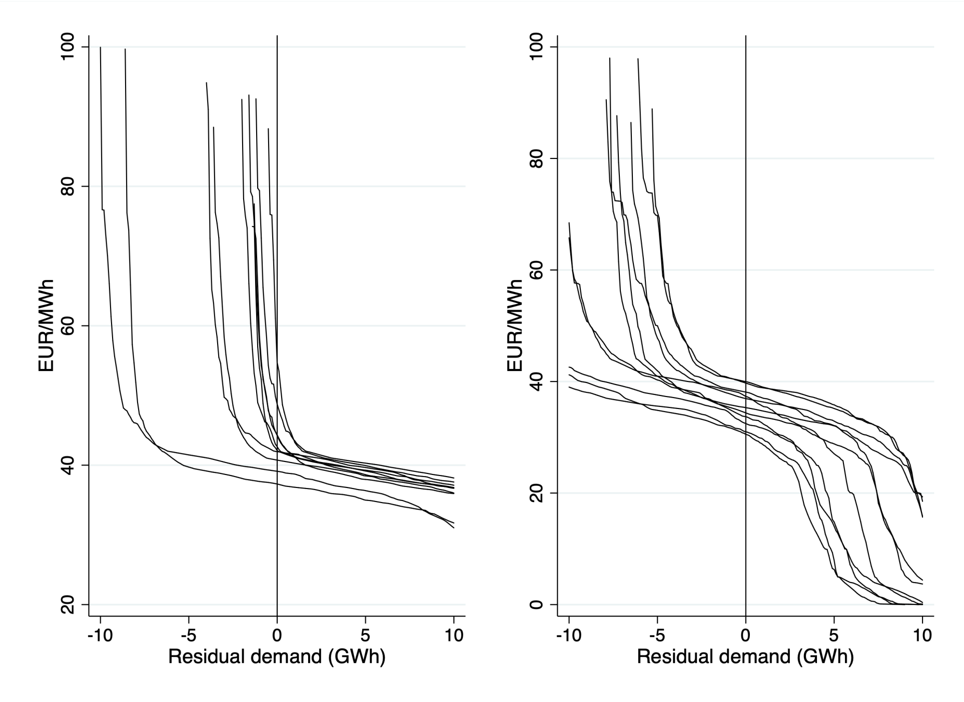
$$q_{hd}^{outage} = \alpha + \beta_0 p_{hd} + \beta_1 \left|\frac{\partial p(D_{hd}^{res})}{\partial D_{hd}^{res}}\right| + \beta_2 temp_{hd} + \mathbf{X}_{hd}\boldsymbol{\gamma} + \boldsymbol{\delta}_h + \boldsymbol{\rho}_m + \varepsilon_{hd} \tag{2}$$

Where q_{hd}^{outage} is the quantity of GWh declared as unavailable during hour h in day d, α is a constant, p_{hd} is the observed equilibrium price, and $|\frac{\partial p_{hd}(D_{hd}^{res})}{\partial D_{hd}^{res}}|$ is the (absolute) slope of the inverse residual demand function facing the nuclear plants. The slope can be computed using observed bidding data. Hence, unlike other markets, this equality can be directly tested.

$\hat{\beta}_0$ is the estimate of the conditional correlation between the outage quantity and the price. It suffers from reverse causality, since expanding nuclear output has a negative effect on the price. Hence, there is no economically meaningful interpretation of $\hat{\beta}_0$. The coefficient of interest is instead $\hat{\beta}_1$. A positive estimate indicates that nuclear output responds to the slope variable beyond the impact of the price. However, this coefficient should also be interpreted as the conditional correlation between the slope variable and nuclear outages, and not as a strictly causal relationship.

In the base specification I also control for temperature, since lower temperatures may lead to a higher frequency of failures or a greater need for maintenance. However, temperature is also a determinant of demand. Lower temperatures are associated with increased demand in the Nordic region due to the demand for heating (air-conditioning is virtually non-existent). Therefore, the direction of the combined temperature effect is not evident since it affects both supply and demand. Further, $\mathbf{X}_{hd}$ is a set of exogenous residual demand shifters with its associated coefficient vector $\boldsymbol{\gamma}$. It includes forecasted system demand, wind power output, and inflow to the hydro reservoirs (hydro inflow is only available on a weekly basis). While forecasted demand has a positive effect on residual demand, wind power output and hydro inflow both have a negative effect. The demand forecast is published by Nord Pool at 11:00 the day before delivery. It does not take short term price variations into account. Instead, it is determined by indicators of weather and economic activity, and should thus not suffer from reverse causality. Finally, $\boldsymbol{\delta}_h$ is a set of 24-hour fixed effects, $\boldsymbol{\rho}_m$ is a set of month-of-sample fixed effects, and ε_{hd} is an error

Figure 4: Nuclear inverse residual demand functions in February and June



Note: Random inverse residual demand functions in February (left) and June (right) respectively, at 5 pm.

term. Standard errors are clustered by week.

5.1 Fitting data to the model

Dependent variables. For each hour of the sample, I compute the size of the total maintenance and forced outages respectively, for all nuclear plants combined. The mean maintenance outage size is 1.4 GWh/h (or 17 percent of installed capacity). The correlation between observed output and outages declared as maintenance is -0.9, demonstrating that maintenance is the main conduit explaining the variation in output. The corresponding figures for failures are 0.4 GWh/h (or 5 percent of installed capacity). Since failures in principle should be random events these estimates could be regarded as placebo tests, although economic incentives may also matter for how swiftly a reactor is put back online after a failure. The correlation between observed output and outages declared as failures is -0.3, demonstrating that failures explain less of the variation in output than maintenance.

Slope variable. Since data on bidding curves are only available at the system level, I assume that all nuclear output is bid into the market as inelastic bids (i.e. at zero price) in order to construct the residual demand function. Since I know that capacity utilization is close to 100 percent after netting out maintenance and failure outages this is a reasonable assumption. It is also consistent with the shape of the observed system supply function, where around half of all accepted bids are inelastic. Thus, I can construct the residual demand function of the nuclear plants according to

$$D_{hd}^{res}(p_{hd}) = D_{hd}^{system}(p_{hd}) - [S_{hd}^{system}(p_{hd}) - q_{hd}^{nuc}]$$

Where $D_{hd}^{system}(p_{hd})$ and $S_{hd}^{system}(p_{hd})$ are the observed system supply and demand functions. Figure 4 depicts a random set of inverse residual demand functions in February and June at 5 pm. In February the slope is generally steeper than in June, since demand is high and the system is close to full capacity utilization. To compute the slope of the inverse residual demand function in equilibrium, I take a quantity window of 0.5 GWh on each side of the market clearing point and interpolate prices at these points to obtain two quantity/price pairs, (Q_1, p_1) and (Q_2, p_2). The (absolute) slope is then computed as $|\frac{\partial p(D_{hd}^{res})}{\partial D_{hd}^{res}}| = |\frac{p_1 - p_2}{Q_1 - Q_2}|$. As a robustness test I also compute the slope by using a quantity window of 0.25 and 1 GWh, respectively. The correlations between all slope measures are above 0.85, confirming that the size of the window is not crucial.[6] The mean slope is 2.6, meaning that a one GWh contraction of nuclear output will result in a 2.6 EUR/MWh increase in the equilibrium price.

Another figure of interest is the corresponding elasticity: multiplying the slope by $\frac{q_{hd}^{nuc}}{p_{hd}}$ gives the percentage increase in the price as a result of a one percent contraction of nuclear output. The mean of this figure is 0.43, meaning that a one percent contraction would on average lead to a 0.43 percent increase in the price. Since nuclear output constitutes about 40 percent of the nuclear owners' total output, the mean elasticity with respect to the nuclear owners' *total* output is close to unity.

5.2 Results

Results are presented in Table 5. In specifications (1)-(4), the dependent variable is maintenance outages. The slope coefficient is positively and precisely estimated in (1)-(2) when including month-of-sample fixed effects. When including all control variables in (2), the coefficient is 0.041. The interpretation is that when the price effect of removing 1 GWh nuclear capacity goes up by 1 EUR, this is associated with a capacity withdrawal of another 0.041 GWh of nuclear capacity. When the month-of-sample fixed effects are replaced by week-of-sample and day-of-sample fixed effects respectively in (3)-(4), the slope coefficient becomes much smaller and is imprecisely estimated, indicating that owners do not respond to short term variations in incentives to exert market power. In columns (5)-(8), the dependent variable is instead capacity availability net of failures. The slope coefficient then becomes small and is imprecisely measured in all specifications, indicating that failures are not used to exercise market power.

[6] Since the auctioneer clears the market by interpolating linearly across the points on the aggregate supply and demand function, the instantaneous slope of the residual demand function at equilibrium is well defined. That is, $|\frac{p_1 - p_2}{Q_1 - Q_2}|$ can be computed with respect to the price/quantity pairs just around the clearing point. However, there are often a great number of points just around the clearing point due to the large number of firms in the market, and the resulting slope often varies substantially by just moving a couple of megawatts away from the equilibrium. Therefore, this slope is usually not informative about the price effect resulting from a nuclear reactor outage. Figure A9 visualizes this relationship, depicting four nuclear residual demand functions along with the corresponding instantaneous slope, and the slope approximated within a 0.5 GWh window around the equilibrium.

Turning to the control variables, the price coefficient is positive and precisely estimated in specifications (1)-(4), indicating reverse causality. The temperature variable is imprecisely measured in all specifications. The demand forecast coefficient has the expected negative sign in most specifications, although it is imprecisely measured. The wind power coefficient is negative in most specifications, which is somewhat counterintuitive since an expansion of wind power should have a negative effect on residual demand. However, strong winds may also have a positive effect on demand due to an increased need for heating (which is only partly accounted for when computing the demand forecast due to forecasting errors). The last control variable, hydro inflow, has the expected positive sign in all specifications where it is included. Since it is only available by week, it cannot be included with the week-of-sample or day-of-sample fixed effects. Since increased hydro inflow is synonymous with a negative residual demand shock, this indicates that more maintenance is performed when the price is low. Hydro inflow is also the only control variable that has a non-trivial effect on the volume of failures, indicating that negative residual demand shocks due to hydro inflow means that failures are fixed more swiftly.

Table 5: Determinants of nuclear outages

	Outages due to maintenance				Outages due to failures			
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Slope	0.056***	0.041***	0.0065	0.0027	0.0031	0.0038	0.00011	0.0011
	(0.014)	(0.013)	(0.0052)	(0.0017)	(0.0064)	(0.0069)	(0.0034)	(0.0013)
Price	0.012***	0.015***	0.0060***	0.00047	0.0020	0.0011	0.00030	−0.00037
	(0.0036)	(0.0037)	(0.0012)	(0.00047)	(0.0020)	(0.0024)	(0.00078)	(0.00036)
Temperature		−0.013**	0.0044	0.00083		0.00046	0.0013	−0.00013
		(0.0066)	(0.0034)	(0.0013)		(0.0040)	(0.0035)	(0.0012)
Demand forecast		−0.0058	−0.0030	−0.0048***		0.0015	−0.00013	−0.0010
		(0.013)	(0.0064)	(0.0016)		(0.0072)	(0.0041)	(0.0011)
Wind power		−0.065*	0.0048	0.033**		−0.014	0.0072	−0.0048
		(0.038)	(0.020)	(0.016)		(0.023)	(0.018)	(0.0094)
Hydro inflow		0.033***				−0.0036*		
		(0.0068)				(0.0021)		
Fixed effects	Month	Month	Week	Day	Month	Month	Week	Day
Cluster level	Week	Week	Week	Day	Week	Week	Week	Day
N	26304	26304	26304	26304	26304	26304	26304	26304

* $p < .10$, ** $p < 0.05$, *** $p < 0.01$
Note: In columns (1)-(4) the dependent variable is nuclear outages due to maintenance, expressed in GWh. Columns (5)-(8) present the corresponding results for failures. Hour-of-the-day fixed effects are included in all regressions.

6 Simulating output under different strategic behaviors

In this section I formulate a more comprehensive model to simulate optimal nuclear output. I simplify the model by constraining owners to change nuclear output only once every week. This modeling choice is consistent with the fact that more than 95 percent of the maintenance periods reported in the Urgent Market Messages database are at least one week long. It is also consistent with the results in Table 5 above, demonstrating that economic incentives do not predict within-week variation in outages. Although it would be possible to allow for within-week variations in the simulation exercise, this would likely generate incentives to perform maintenance in much shorter intervals than what would be technically feasible. Further, I acknowledge that firms are forward contracted, i.e., profits are the sum of profits on the day-ahead as well as the forward market. I simulate output under three behavioral assumptions:

Cournot competition The majority owner of each plant chooses a level of output that maximizes the sum of its own profit from nuclear and other production. This means that Vattenfall takes the output decisions in Ringhals and Forsmark, while E.ON takes the output decisions in Oskarshamn. In the simulation for Vattenfall, Ringhals and Forsmark are aggregated to resemble one large plant, since the marginal cost of nuclear is constant. Fortum remains a passive owner in all plants. The majority owner takes into account both other firms' passive ownership in the plant it controls, as well as its passive ownership in plants where it is a minority owner.

I denote the profit of majority owner i in hour h of day d by π^i_{hd}, and the output in the nuclear plant(s) controlled by majority owner i by q^i_{hd}, with the associated capacity $\overline{q}^i$. The inverse residual demand function facing firm i's nuclear plant is $p^i_{hd}(q^i_{hd})$, firm i's supply function net of nuclear output is $S^i_{hd}(p^i_{hd}(q^i_{hd}))$, the constant marginal cost of nuclear is f, and the total cost of other production is $C^i_{hd}(p^i_{hd}(q^i_h d))$. Further, the ownership share in firm i's own plant is denoted by η^i_i, and i's passive ownership shares in the plants controlled by firm $j \neq i$ are η^i_j. The price of the forward obligations is p^{ci}_{hd}, and the forward contracting volume is x^i_{hd}.

The objective function of firm i is then:

$$\max_{q^i_{hd}} \quad \pi^i_{hd} = \underbrace{p^i_{hd}(q^i_{hd})[\eta^i_i q^i_{hd} + \sum_{j \neq i} \eta^j_i q^j_{hd} + S^i_{hd}(p^i_{hd}(q^i_{hd}))]}_{\text{Spot market revenue}} - \underbrace{f[\eta^i_i q^i_{hd} + \sum_{j \neq i} \eta^j_i q^j_{hd}] - C^i_{hd}(p^i_{hd}(q^i_w))}_{\text{Spot market cost}}$$

$$+ \underbrace{[p^{ci}_{hd} - p^i_{hd}(q^i_{hd})]x^i_{hd}}_{\text{Financial profit}} \tag{3}$$

Subject to the constraints:

$$q^i_{hd} \leq \overline{q}^i_w \tag{4}$$

$$p^i_{hd}(q^i_{hd}) \leq 2000 \ EUR/MWh \tag{5}$$

$$q^i_k = q^i_l \ \forall k, l \in \mathbf{w} \tag{6}$$

Where (4) is the capacity constraint. The next constraint (5) reflects the Nord Pool price cap of 2000 EUR/MWh, which could potentially be binding when firms are net pivotal. A firm's pivotal quantity is the quantity at which its residual demand curve becomes perfectly inelastic and the price cap is reached. If this quantity is greater than zero, the firm is pivotal. However, as discussed in McRae and Wolak (2014), what matters for a firm's incentives is whether it is *net* pivotal. A firm is net pivotal if the difference between its pivotal quantity and its fixed-price forward market obligations quantity is positive. Given the approximated forward obligations computed in Section 3.2, the largest firm Vattenfall is net pivotal during 3 percent of all hours in the sample, and E.ON is never net pivotal. Last, constraint (6) states that nuclear output has to be the same for all hours belonging to the same week-of-sample w.

It is also worth noting that although the forward price p^{ci}_{hd} is included in the firm's profit function, optimal nuclear quantity is invariant to this variable since it affects profit equally over the whole range of potential output.

Solution technique To fit data to the model, I start by discretizing the hourly inverse residual demand functions $p^i_{hd}(q^i_{hd})$ in blocks of 100 MWh. I estimate firm i's bid from non-nuclear production according to $S^i_{hd}(p^i_{hd}) = \lambda^i[S^{system}_{hd}(p_{hd}) - q^{nuc}_{hd}]$, where the scalar λ^i is firm i's market share on non-nuclear output on the day-ahead market from Table 2.

In the baseline model I assume that all non-nuclear output is bid into the market at marginal cost. Thus, firm i's cost function of non-nuclear output is $C^i_{hd}(p^i_{hd}) = \int_{p^{min}_{hd}}^{p^i_{hd}} S^i_{hd}(x)dx$. The assumption of competitive bidding is certainly a simplification, and in the robustness section I solve the model for a range of parameter values reflecting a markup of 0 to 30 percent. Forward volumes for each week are computed as described in Section 3.2.

The Cournot equilibrium is solved by first computing the best-response function for each firm (Vattenfall and E.ON) during each separate sample week. Hence, I compute the residual demand function given every possible quantity of the competitor, compute the associated profits, and perform a grid search to find the profit maximizing quantity. Figure A10 depicts a set of weekly profit functions for Vattenfall. As seen in the figure, weekly profit functions are not always concave, so a first-order solution technique would not be appropriate.

Using the best-response functions I then search for the equilibrium point, i.e., where the best-response functions of both firms intersect. In some instances there are multiple equilibria, due to the non-concavity of some of the profit functions. Since I want to test whether there exists *some* Cournot equilibrium that is consistent with the observed quantities, I then proceed by searching for the equilibrium with the smallest deviation from observed output. I compute this deviation as the sum of the (absolute) deviations between the simulated and observed quantity for both firms i and j, i.e., $deviation = |q^i_{obs} - q^i_{sim}| + |q^j_{obs} - q^j_{sim}|$.

Collusion and divested solution. Letting π^{joint}_{hd} be the joint profit on the owners' total output, q^{nuc}_{hd} aggregate nuclear output, and $S^{joint}_{hd}(p^{joint}_{hd})$ the nuclear producers' joint bid on non-nuclear output, the objective function under collusion becomes:

$$\max_{q^{nuc}_{hd}} \quad \pi^{joint}_{hd} = \underbrace{p^{joint}_{hd}(q^{nuc}_{hd})[q^{nuc}_{hd} + S^{joint}_{hd}(p^{joint}_{hd}(q^{nuc}_{hd}))]}_{\text{Spot market revenue}} - \underbrace{f q^{nuc}_{hd} - C^{joint}_{hd}(p^{joint}_{hd}(q^{nuc}_{hd}))}_{\text{Spot market cost}}$$

$$+ \underbrace{[p^{cjoint}_{hd} - p^{joint}_{hd}(q^{nuc}_{hd})]x^{joint}_{hd}}_{\text{Financial profit}} \tag{7}$$

Letting π^{nuc} be the profit on the nuclear plants alone, the corresponding objective function under the divested model becomes:

$$\max_{q^{nuc}_{hd}} \quad \pi^{nuc}_{hd} = \underbrace{p^{nuc}_{hd}(q^{nuc}_{hd})q^{nuc}_{hd}}_{\text{Spot market revenue}} - \underbrace{f q^{nuc}_{hd}}_{\text{Spot market cost}} + \underbrace{[p^{cnuc}_{hd} - p^{nuc}_{hd}(q^{nuc}_{hd})]x^{nuc}_{hd}}_{\text{Financial profit}} \tag{8}$$

Where both models are subject to the analogous constraints as under Cournot competition. Under collusion, firms are jointly net pivotal during 9 percent of all hours. Under the divested solution, the nuclear plants alone are never net pivotal.

When computing forward volumes under the divested solution, I use market shares on nuclear only (otherwise firms would become heavily over-contracted). Figure A11 depicts the estimated forward volumes and observed nuclear output under the divested solution. Observed nuclear output follows estimated forward sales well, and observed output exceeds the estimated forward volume during 97 percent of all weeks in the sample.

Solution technique. These models are univariate optimization problems, and thereby easier to solve than the Cournot model. Just as in the Cournot case, I start by discretizing the residual demand functions in blocks of 100 MWh each, compute the associated weekly profits for each output level, and search for the profit maximizing quantities.

6.1 A dynamic extension

Solving for the optimal output trajectories under the different models highlights both differences in incentives to reduce the mean level of output, as well as incentives shaping the intertemporal allocation of output. However, the models are silent about the minimum level of maintenance needed for refueling and keeping the reactors in compliance with safety standards. For example, the divested model generates an optimal output path that implies close to full capacity utilization during extended periods. Evaluating which behavioral model fits data best is then challenging, as it relies on the researchers' ability to assess if necessary maintenance obligations could be fulfilled given each specific solution.

Therefore, I also solve the models while keeping the mean capacity factors at the observed levels, mitigating the possibility that maintenance obligations could not be fulfilled. As noted by Bushnell (2003), the optimization problem is now very similar to that of a hydro power plant with a reservoir, since expanding output in one period means that there is less water in the reservoir to use during the following period.

A possible way to model this intertemporal scheduling choice is to impose a constraint on the mean yearly capacity factors. However, solving such a model would be intractable, involving many degrees of freedom. Further, maintenance could then be allocated completely freely within each year without any further considerations about the technical feasibility of the specific output trajectories. For example, it may not be technically feasible to allocate *all* maintenance to the summer season, even if such an allocation would be optimal given the model assumptions.

Instead, I consider a more tractable constraint by only allowing for reallocation of output across consecutive weeks. That is, I divide the sample into periods of two weeks each, and impose the constraint that the sum of output across consecutive weeks should equal the sum of the observed output during those weeks. Letting $\mathbf{z}$ be the set of all integers up to 78 (there are 156 weeks in the sample), the dynamic constraint becomes:

$$\sum_{j=w}^{j+1} q_w^i = \sum_{j=w}^{j+1} q_w^{i(obs)} \; \forall w = 2z + 1 \tag{9}$$

Which creates a set of 78 periods with 2 weeks in each period. Omitting the capacity constraint, the general optimization problem for week w becomes:

$$\max_{q_w^i} \quad \sum_{j=w}^{j+1} \pi_w^i \; \forall w = 2z + 1 \tag{10}$$

In contrast to a more flexible approach with higher degrees of freedom, the model is straightforward to solve since the output choice in any given week $w+1$ is the residual from the output choice in week w.

Solution technique To solve for the Cournot quantities, I compute the best-response for every possible quantity combination of the competitor during each of the 78 two-week periods. That is, each point on a best-response function will be associated with four quantities: two for the competitor and two for the own output. Since the quantity in week $2z+1$ is directly determined by the quantity in the previous week, this results in 78 response functions for each firm. I then proceed by finding the intersection of the best-response functions as in the static model. There a few instances where no equilibrium is found. For each firm, I then search for the quantity pair that maximizes profits given the *observed* output of the other firm during that two-week period.

To find optimal output under the univariate models, I proceed analogously by computing the profits associated with every possible quantity combination during the 78 two-week periods, and search for the profit maximizing quantity-pair during each period.

6.2 Results

Figure A12, A13, and A14 depict monthly aggregated simulated output trajectories given each behavioral assumption under the static model, as well as the observed output trajectory. Simulated output follows observed output well, and the collusive model generates the strongest incentives to contract output, followed by the Cournot and divested models, respectively. Figure A15, A16, and A17 instead depict the corresponding weekly output trajectories, revealing that the simulation generates incentives to vary output in shorter intervals than what is observed in the data. This is not surprising, since the model does not incorporate any additional cost of varying output swiftly. Adding such constraints would require a substantially more complex solution technique.

Summary statistics of market outcomes are presented in Table 6. Prices and profits are computed as percentages of the corresponding figure given observed nuclear output. Profits are the sum of the profits on all three nuclear owners' total generation, including non-nuclear. Below, I discuss results under the static and dynamic model respectively.

Static model. Under the static specification (left column in Table 6), the collusive model generates stronger incentives to withhold capacity than the other models, with a mean capacity factor of 76 percent, compared to 89 for the Cournot model and 94 for the divested solution. Notably, the collusive model matches the observed mean capacity factor of 76 percent exactly.

The volume-weighted average price under the collusive model is 118 percent of the observed price. Under the Cournot model, the corresponding figure is 105 percent, and under the divested model it is instead 97 percent. An important reason for the relatively high mean price under the collusive model is a few price spikes during the winter. When comparing median prices, the collusive price is instead 110 percent of the observed price.

Table 6: Descriptive statistics of simulated market outcomes

Model	Static	Dynamic
Collusion		
Capacity factor	76	76
Equilibrium price	118	107
Profit	128	109
Cournot		
Capacity factor	89	76
Equilibrium price	105	106
Profit	127	108
Divested		
Capacity factor	94	76
Equilibrium price	97	105
Profit	119	107

Note: Capacity factors are expressed in percentages. Prices and profits are computed as percentages of the corresponding figure given observed nuclear output. Profits are the sum of the profits on all nuclear owners' total generation, including non-nuclear.

As expected, profits are higher under the collusive model than the other models, at 128 percent of the observed figure, compared to 127 percent for the Cournot model and 119 percent for the divested solution. To enable comparisons across models, profits are computed as the sum of profits including non-nuclear output for all owners. Since profits also include profits on the forward obligations, figures are based on the simplified assumption that forward prices equal the corresponding simulated spot prices, i.e., there is no arbitrage.

In terms of allocative efficiency, the welfare effects of contracting nuclear output are in principle negligible due to a highly inelastic short term demand. However, there are likely negative effects on productive efficiency. First, since the marginal cost of nuclear is lower than for other thermal plants, system production costs increase when these plants expand output as a response to the contraction in nuclear output. Second, *shifting* nuclear maintenance towards periods with a relatively price sensitive residual demand (while keeping total nuclear output constant) leads to increased system production costs when the residual demand function is convex (due to Jensen's inequality). However, since I do not observe generation unit level output for the other thermal plants, it is not possible to appropriately quantify these inefficiencies using the current modeling framework. Furthermore, thermal units only account for a relatively small fraction of total production, since the market is dominated by hydroelectric units which have little or no direct cost of production. Within the current modeling framework, it is not possible to appropriately quantify the extent to which these hydroelectric units alone are able to compensate for the variation in nuclear output.

Dynamic model. When including the dynamic constraint in eq. (9), results are qualitatively similar to the static specification (right column in Table 6), although differences are much less pronounced since the only way to generate changes in market outcomes is by shifting output across consecutive weeks.

The price under collusion is still higher than under the other models, but only at 109 percent of the observed price compared to 108 and 107 percent for the Cournot and divested models respectively. Also, profits are only marginally higher under the collusive model compared to the other models.

6.3 Model selection

To examine model fit, I regress observed output on simulated output under each model according to:

$$q_w^{obs} = \alpha + \gamma_0 q_w^{sim} + \varepsilon_w \tag{11}$$

Where q_w^{obs} is the observed aggregate weekly output of all plants, α is a constant, q_w^{sim} is the corresponding simulated output with its associated coefficient γ_0, and ε_w is the error term. A perfect fit implies that $\gamma_0 = 1$ and $R^2 = 1$. When estimating the dynamic specification, I begin by computing the mean output during each consecutive two-week period. Due to the dynamic constraint, this figure is identical for both observed and simulated output. I then subtract this mean from q_w^{obs} and q_w^{sim}, and regress the corresponding demeaned variables. Otherwise, adjusted R^2 would become very large. In the static specifications, standard errors are clustered by month, and in the dynamic specifications standard errors are cluster by every two-week period.

Results are reported in Table 7, where each column presents the results from a separate regression.

Table 7: Dependent variable: Observed weekly output

	Static			Dynamic		
	Collusion	Divested	Cournot	Collusion	Divested	Cournot
Simulated output	0.26***	0.59***	0.24**	0.21***	0.22***	0.07***
	(0.058)	(0.16)	(0.10)	(0.036)	(0.043)	(0.022)
Constant	5.17***	1.89	5.03***	0.00	0.00	0.00
	(0.40)	(1.36)	(0.84)	(22.0)	(22.4)	(24.0)
Cluster level	Month	Month	Month	Two weeks	Two weeks	Two weeks
R^2	0.19	0.16	0.07	0.18	0.15	0.07
N	156	156	156	156	156	156

* $p < .10$, ** $p < 0.05$, *** $p < 0.01$
Note: The dependent variable is observed aggregate nuclear output. Each column presents the results from a separate regression. Standard errors in parentheses.

Results from the static model are presented in the first three columns. All models yield positive and statistically significant estimates of $\hat{\gamma}_0$. Using R^2 as goodness of fit measure, the collusive model fits data best with an adjusted R^2 of 0.19. The corresponding figures for the divested and Cournot models are 0.16 and 0.07 respectively. All coefficients are less than unity, demonstrating that a unit change in simulated output corresponds to less than a unit change in observed output. This is expected, since the model does not impose any additional cost of varying output swiftly. Further, the constant terms lie in the interval between zero and the mean level of observed output (which is 6.9 GWh/h).

The last three columns present the results under the dynamic specification. Also here, all estimates yield positive and highly significant estimates of $\hat{\gamma}_0$, and the collusive model matches data best, followed by the divested and the Cournot models respectively. Also under this model, all coefficients are less than unity.

A relevant question is then whether the collusive model *alone* can explain the variation in observed output, or if firms exhibit behavior that can partly be explained by the other models. To test this, I perform a J-test of non-nested hypotheses following Davidson and MacKinnon (1981). The same procedure has also been used by e.g. Bushnell et al. (2008), although their main variable of interest is simulated prices and not quantities. To perform the J-test, I consider the following comprehensive model:

$$q_w^{obs} = \rho + (1 - \theta^{alt})\beta_0 q_w^{coll} + \theta^{alt}\beta_1 q_w^{alt} + \varepsilon_w \tag{12}$$

Where ρ is a constant, q_w^{alt} is the simulated output profile of the alternative hypothesis, i.e., Cournot competition or the divested solution, and the mixing parameter θ^{alt} determines the relative weight on the alternative model for predicting firm conduct. When no *a priori* information is available, the mixing parameter is not identifiable in the comprehensive model. The J-test works around this by replacing $\beta_1 q_w^{alt}$ with the fitted values from a regression of q_w^{obs} on q_w^{alt}, and then testing the mixing parameter for statistical significance, i.e., $H_0 : \theta^{alt} = 0$. If the null hypothesis is not rejected, it is also necessary to "reverse" the model and test $H_0 : \theta^{coll} = 0$ to confirm that this new null hypothesis is indeed rejected.

Table 8 displays the p-values for different tests under both the static and dynamic specification. As seen in Table 8, $H_0 : \theta^{coll} = (1 - \theta^{alt}) = 0$ is rejected in all cases. The interpretation is that there is some variation in the data that can only be explained by the collusive model. Further, $H_0 : \theta^{alt} = 0$ is rejected for both competing models in the dynamic case. However, in the static case it is not rejected for the divested model. The interpretation is that explanatory power is improved when also including information from this model.

Hence, it appears that firms are not always able to coordinate on the collusive equilibrium. There are several reason why firms may not achieve perfect coordination. In the literature, the most discussed one is due to the folk theorem, stating that any quantity between Cournot competition and joint profit maximization is compatible with some Nash equilibrium in an infinitely repeated game.

However, in the current setup a more likely reason is regulatory threat. As discussed in Section 3.3, by the Code of Conduct nuclear owners are obliged not to perform mainte-

Table 8: J-test of non-nested hypotheses

Alternative model	$H_0 : \theta^{alt} = 0$	$H_0 : \theta^{coll} = 0$
Divested		
Static	0.01	0.00
Dynamic	0.35	0.04
Cournot		
Static	0.44	0.00
Dynamic	0.80	0.00

Note: The table displays p-values for the null hypothesis in several J-tests of non-nested hypotheses.

nance during the winter season (November-March) unless it can be motivated for safety reasons (Energy Markets Inspectorate, 2010). If excessive maintenance would be performed despite the regulatory obligation to refrain from doing so, the probability of the introduction of a severely stricter regulatory framework would increase drastically. The fact that the general public is more alert to nuclear plant activities during the winter season is likely another contributing reason why behavior may be comparatively more competitive during this period.

If firms behave more competitively during the winter season for reasons unrelated to the repeated games literature of oligopolistic competition, a more explicit coordination device would facilitate the transition between different modes of competition. As discussed in Section 3.3, the same person often serves as a board member in several of the nuclear plants, as well as in other production divisions of the owner that it represents. Such interactions should facilitate this transition.

To test if firms behave more competitively during the winter season, I consider a hybrid case by considering the indicator $winter = 1$ for all observations November-March and letting

$$q_w^{hybrid} = \begin{cases} q_w^{divest} & \text{if } winter = 1 \\ q_w^{coll} & \text{otherwise} \end{cases}$$

Regressing observed output on q_w^{hybrid} now yields an R^2 of 0.29, a figure that is about 50 percent higher than when considering the collusive model alone, consistent with the hypothesis that the threat of regulatory intervention has a pro-competitive effect during the winter season. If constructing the inverse of q_w^{hybrid} by instead inserting values from the collusive model during the summer and vice versa, R^2 instead becomes very low, at 0.05. Further, when regressing observed output on q_w^{hybrid} under the dynamic specification, R^2 also becomes greater than under the collusive model at about 0.2, even if the relative increase in R^2 is now less pronounced.

6.4 Robustness

Solving for the competitive solution. Since high volumes of forward contracts may generate incentives to behave similar to a competitive firm, I simulate output under the assumption that nuclear owners behave competitively. In the static case, this means that nuclear output expands until the price equals the marginal fuel cost of 5 EUR/MWh. Applying this assumption to data generates a mean capacity factor of 98 percent, i.e., the capacity constraint binds almost every week. The mean price is then 34 EUR/MWh, or correspondingly 87 percent of the observed price. Since the variation in simulated output is then trivial, regressing observed output on simulated output does not provide any useful information. Under the dynamic specification, a competitive firm shifts output towards the week with the highest price until prices between consecutive weeks are equalized, or when the capacity constraint binds. Applying this assumption to data generates a price that is 2 percent lower than the observed price. Regressing observed output on simulated output is now informative of model fit, and generates an R^2 of 0.1, which is lower than the corresponding figures for both the collusive and divested models. Further, the J-test rejects the competitive solution in favor of the hybrid model.[7]

A comparison to Finnish nuclear output. Since the competitive solution generates implausibly high capacity factors under the static model, it is useful to also compare observed output to other similar plants in the region. As noted in Section 3.3, Finland is the only other Nordic country with nuclear capacity. The Finnish plants have high capacity factors by international standards, and prices in Finland follow closely prices in Sweden. For competitive firms, incentives when to schedule maintenance are therefore in principle identical. Therefore, I also regress observed Swedish weekly aggregate output on the corresponding hypothetical output given that Swedish weekly capacity factors would match those of the Finnish plants, to examine how the predictive power compares to that of the simulated hybrid model.

It is important to recall that the hybrid model does not capture all relevant aspects of maintenance scheduling. First, maintenance is usually planned several weeks or even months ahead, while the simulations assume that residual demand is known. Second, by visual inspection it is clear that the simulated output has a higher variance than observed output, indicating that there is a cost of swiftly taking down a reactor for maintenance that is not captured by the simulations. Both of these aspects are captured by the Finnish data, and it is therefore expected that Finnish output can predict aspects of maintenance scheduling that the simulations fail to recognize. A J-test comparing the predictive power of the Finnish "model" to that of the hybrid model confirms this hypothesis, revealing that no variable can be rejected in favor of the other. [8]

Next, I test for parameter sensitivity in several dimensions. For each associated parameter value, I solve for optimal output and regress observed output on simulated optimal output according to eq. (11) under both the static and dynamic specifications. I then plot R^2

[7]Testing the hybrid model against the competitive solution yields a p-value of 0.01 associated with the null hypothesis $H_0 : \theta^{hybrid} = 0$, and a p-value of 0.37 associated with the null hypothesis $H_0 : \theta^{comp} = 0$.

[8]Testing the hybrid model against the Finnish "model" yields a p-value of 0.04 associated with the null hypothesis $H_0 : \theta^{hybrid} = 0$, and a p-value of 0.01 associated with the null hypothesis $H_0 : \theta^{Finland} = 0$.

as a function of the corresponding parameter. Results are depicted in Figure A19 and A20 respectively. In all robustness tests, the hybrid model performs best for the whole range of parameter values. However, the sensitivity in R^2 differs depending on the type of parameter tested.

Markup on non-nuclear output. In the first robustness test, I scale down the cost function of non-nuclear output, $C^i_{hd}(p^i_{hd})$, by a factor reflecting a markup between 0 to 30 percent. The impact on R^2 is marginal throughout all specifications.

Nuclear marginal cost. I let the nuclear marginal cost f vary between 0 to 10 EUR/MWh. R^2 is slightly increasing in the marginal cost within all models under the static case, while it is invariant in the dynamic case. The latter result is mechanical: Since aggregate nuclear output is given exogenously for each two-week period, varying f cannot affect the optimal intertemporal allocation of output.

Hedging ratio. I multiply the reported hedging ratio of each firm by a factor ranging between zero to unity. R^2 is now comparatively sensitive to the parameter value chosen, although the hybrid model still performs best throughout. It is notable that the best fit is achieved when forward contracts are assumed to be non-existent, and that this result is driven mainly by the collusive model. Although it is beyond the scope of this paper to comprehensively analyze optimal behavior under forward contracts, one potential explanation is given by Liski and Montero (2006). They note that the standard pro-competitive result by Allaz and Vila (1993) relies on a static model where the spot market is cleared only once. In real markets, a repeated game setting is more appropriate, with multiple rounds of spot market clearings. Within such a setting, they show that firms may maintain short positions in the forward market while still achieving perfect collusion on the spot market, and hence also collusive profits (since the forward price equals the expected spot price). Forward contracting may even expand the range of discount factors for which maximal collusion can be sustained.

Market share on non-nuclear output. I symmetrically scale each λ^i to reflect a combined day-ahead market share on non-nuclear output between 0 and 100 percent (the observed figure is 34 percent). R^2 is now comparatively sensitive, although the hybrid model still performs best throughout. Notably, the worst fit is achieved by letting $\lambda^i = 0$ for all i (i.e., when both the collusive and hybrid models converge to the divested model), consistent with the view that owners also consider profits on other output when optimizing nuclear output. However, R^2 is increasing up until a market share of about 65 percent, i.e., a figure that is almost twice as large as the observed figure. The incentives generated by assuming a high non-nuclear market share are very similar to the incentives generated by assuming a low hedging ratio, since in both cases price variations on the day-ahead market are factored into the firms' profit functions to a greater extent. In light of the previous results demonstrating that R^2 is decreasing in hedging ratio, it is therefore not surprising that R^2 is also increasing in the market share on non-nuclear output.

7 Conclusion

I study the anticompetitive effects of joint ownership of Swedish nuclear plants, finding indications of collusive behavior by means of capacity reductions. However, I find that behavior is relatively more competitive during the winter period, when demand peaks, regulatory oversight is stricter, and the general public is more alert to nuclear power activities in general.

From a regulatory perspective it is of special interest that market power is exercised by withdrawing capacity from the market. This means that the regulator cannot effectively monitor firms by estimating the markup on existing bids. Since maintenance schedules are available to other market participants through the Urgent Market Messages database, messages may be used to share information about schemes on how to exercise market power. Further research could investigate if strategic incentives shape the way that firms reveal new information to the market, and examine whether the mandatory publication of maintenance schedules has resulted in a more competitive outcome (which is the regulator's intention), or if it has facilitated anticompetitive coordination. Since the EU is currently implementing regulations to increase the transparency in electricity markets in which maintenance scheduling is an essential element (ACER, 2015), the findings in the present paper are highly relevant from a policy perspective. In most other electricity markets, firms are not completely free to choose the timing of maintenance themselves, but are obliged to reschedule if the transmission system operator finds that too much capacity will be offline at the same time. The findings in the present paper suggest that such an arrangement could lead to a more efficient allocation of maintenance also in the Nordic region.

Another way to promote competition in the day-ahead market may be to oblige firms to sell a larger share of their output (both nuclear and non-nuclear) through fixed-price forward contracts. Such regulatory interventions have previously been used in several other European countries, for example France, Belgium, Spain, Denmark, Germany, and Portugal (Ausubel and Cramton, 2010).

Last, it is important to emphasize that the low capacity factors of the Swedish nuclear plants may at least in part be explained by the political decision in 1980 (by referendum) to gradually phase out nuclear. This decision may have incentivized owners to refrain from large-scale investments that could have mitigated the need for frequent maintenance disruptions. Still, the current analysis provides empirical evidence that the foregone revenues due to the capacity reductions have presumably been offset by an increase in revenues on the owners' non-nuclear output.

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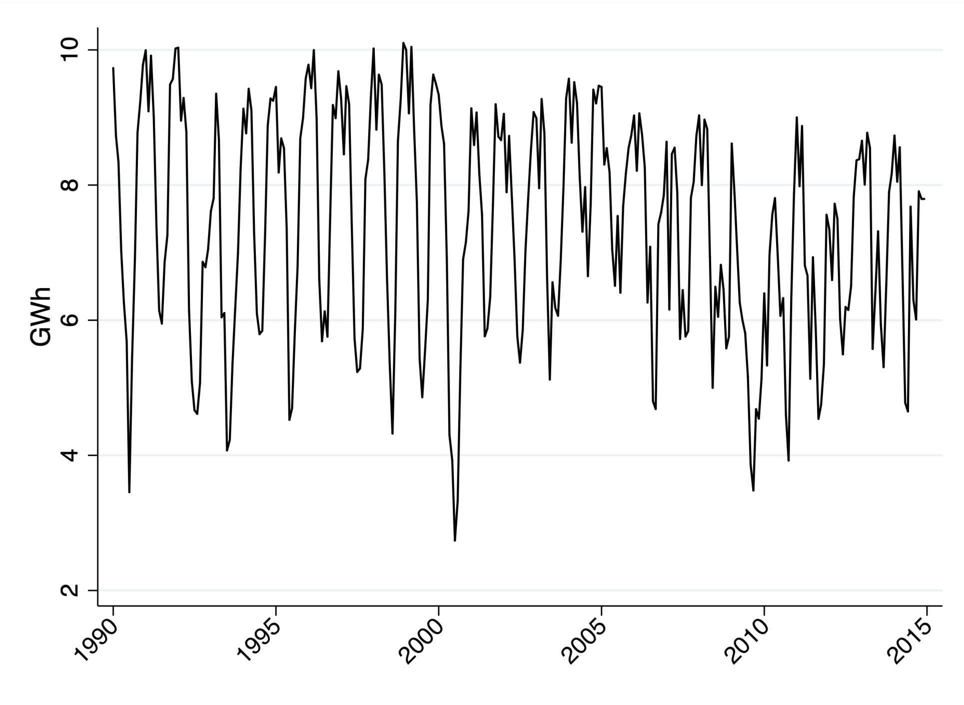
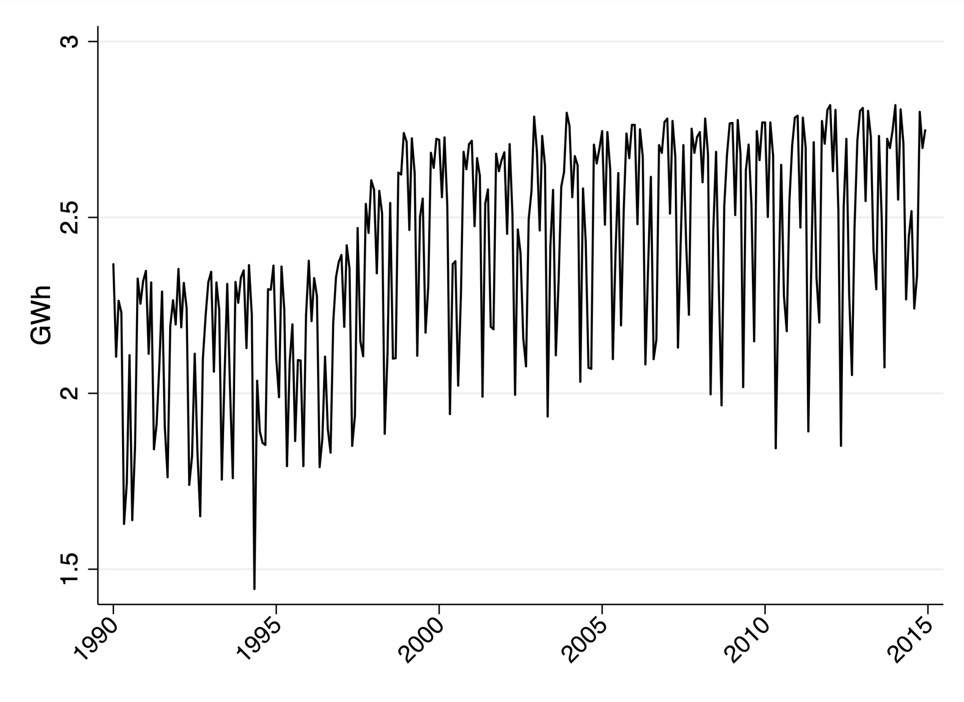
Appendix A

Figure A1: Swedish nuclear output 1990-2014



Note: Swedish nuclear output 1990-2014. Mean hourly output each month-of-sample.

Figure A2: Finnish nuclear output 1990-2014

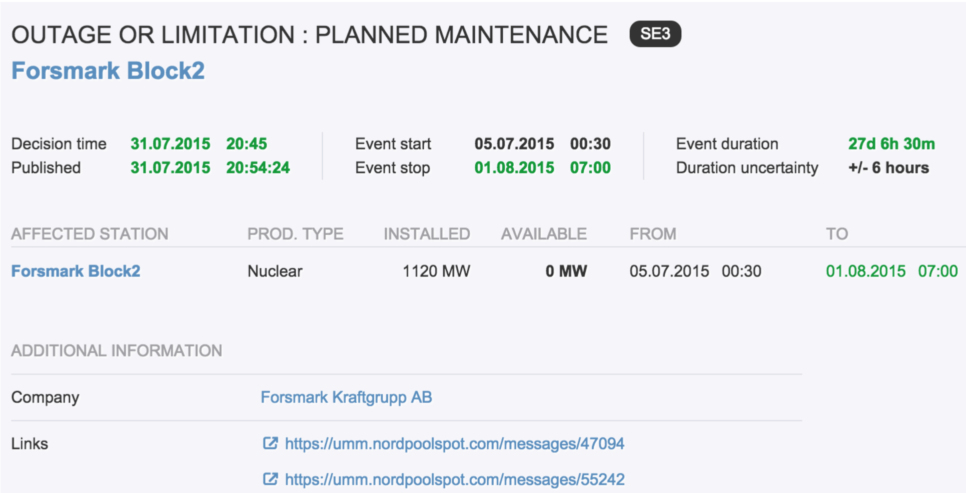


Note: Finnish nuclear output 1990-2014. Mean hourly output each month-of-sample.

Figure A3: Price zones in the Nordic electricity market

Note: Price zones in the Nordic electricity market. All Swedish nuclear plats are located in zone “SE3”.

Figure A4: Example of an Urgent Market Message



OUTAGE OR LIMITATION : PLANNED MAINTENANCE SE3

Forsmark Block2

Decision time	31.07.2015 20:45	Event start	05.07.2015 00:30	Event duration	27d 6h 30m
Published	31.07.2015 20:54:24	Event stop	01.08.2015 07:00	Duration uncertainty	+/- 6 hours

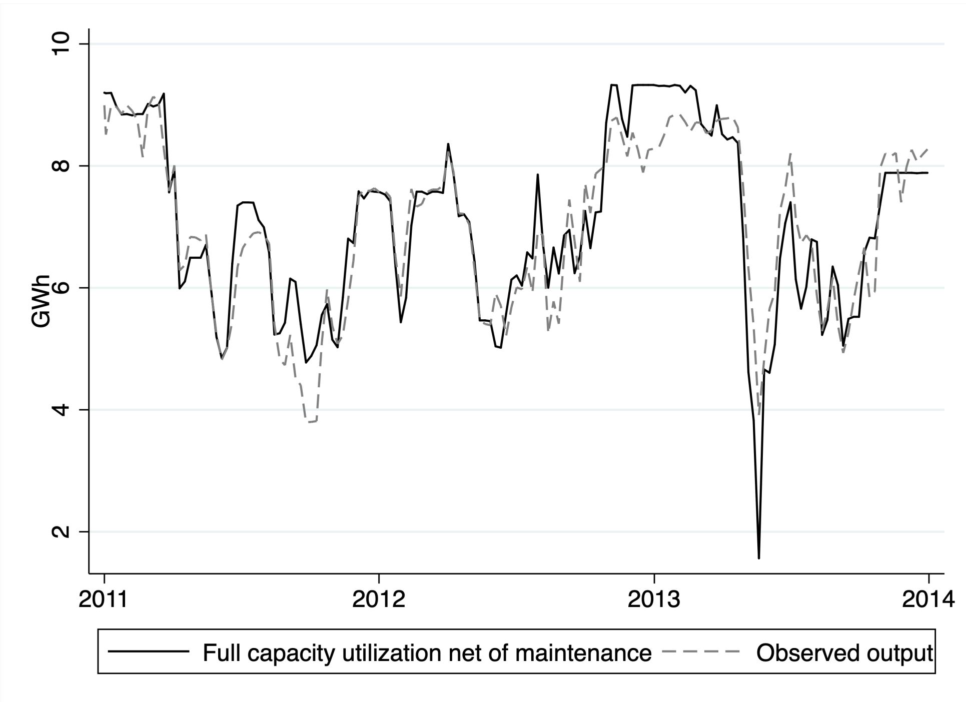
AFFECTED STATION	PROD. TYPE	INSTALLED	AVAILABLE	FROM	TO
Forsmark Block2	Nuclear	1120 MW	0 MW	05.07.2015 00:30	01.08.2015 07:00

ADDITIONAL INFORMATION

Company	Forsmark Kraftgrupp AB
Links	https://umm.nordpoolspot.com/messages/47094
	https://umm.nordpoolspot.com/messages/55242

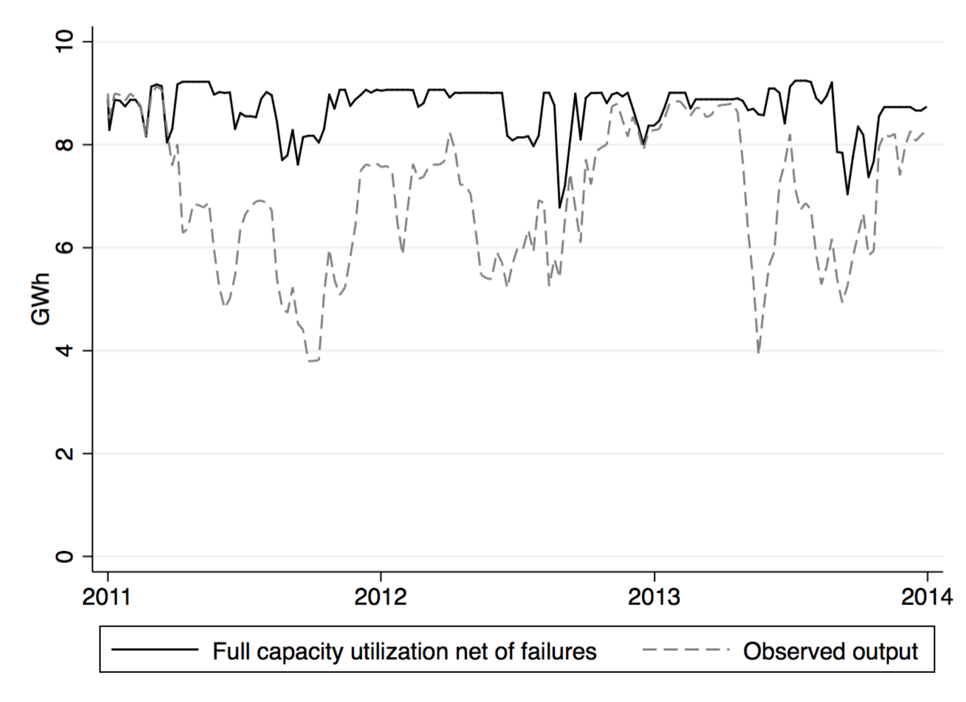
Note: An example of an Urgent Market Message regarding planned maintenance in reactor 2 in Forsmark.

Figure A5: Full capacity utilization net of outages reported as maintenance



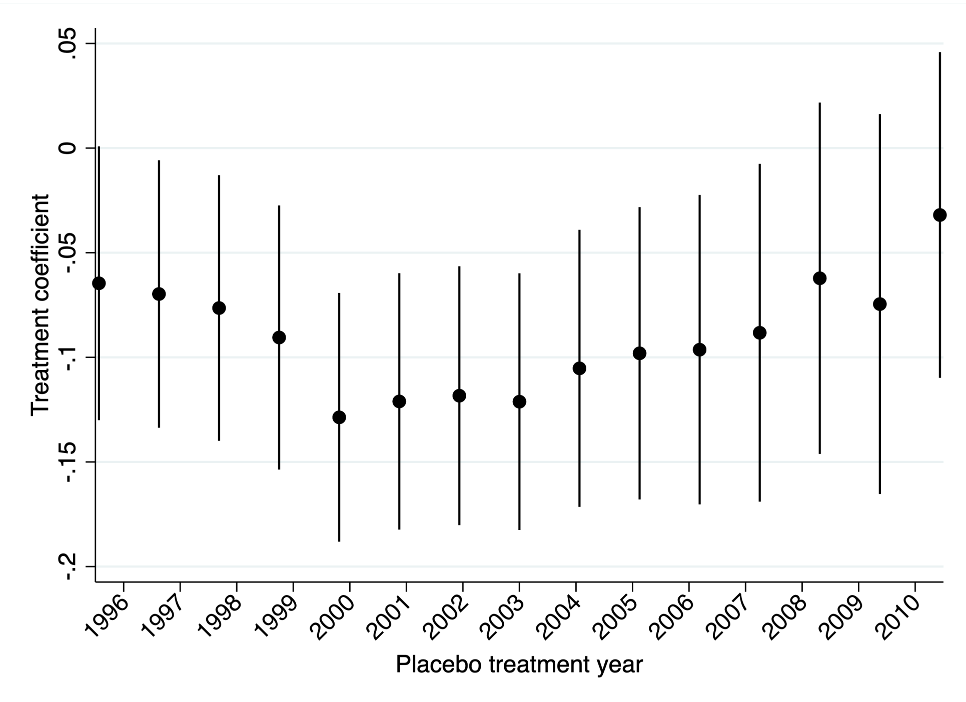
Note: Mean weekly aggregated nuclear output under the assumption that all plants would operate at full capacity except during outages reported as maintenance.

Figure A6: Full capacity utilization net of outages reported as failures



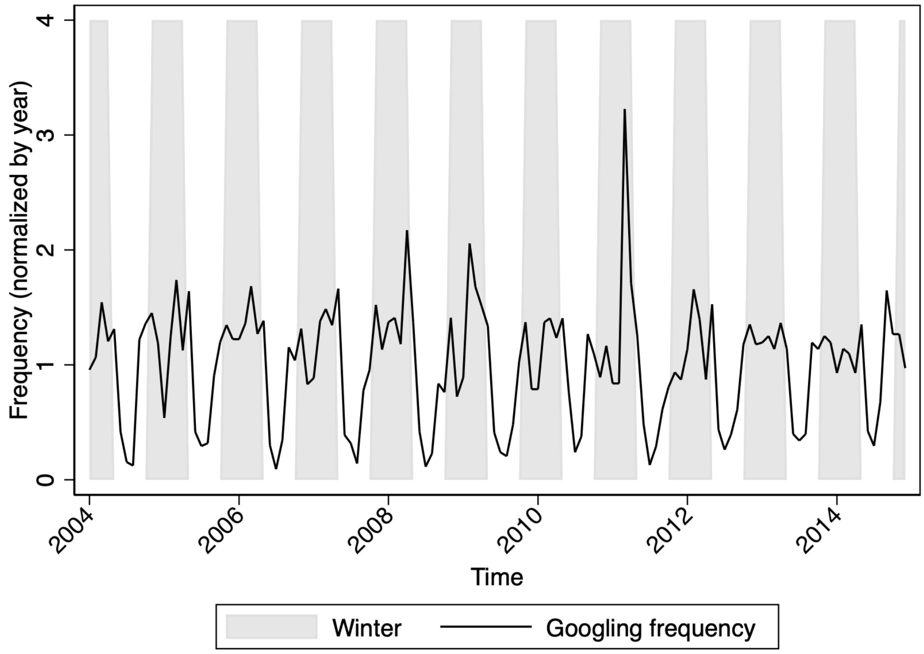
Note: Mean weekly aggregated nuclear output under the assumption that all plants would operate at full capacity except during outages reported as failures.

Figure A7: DiD placebo estimates



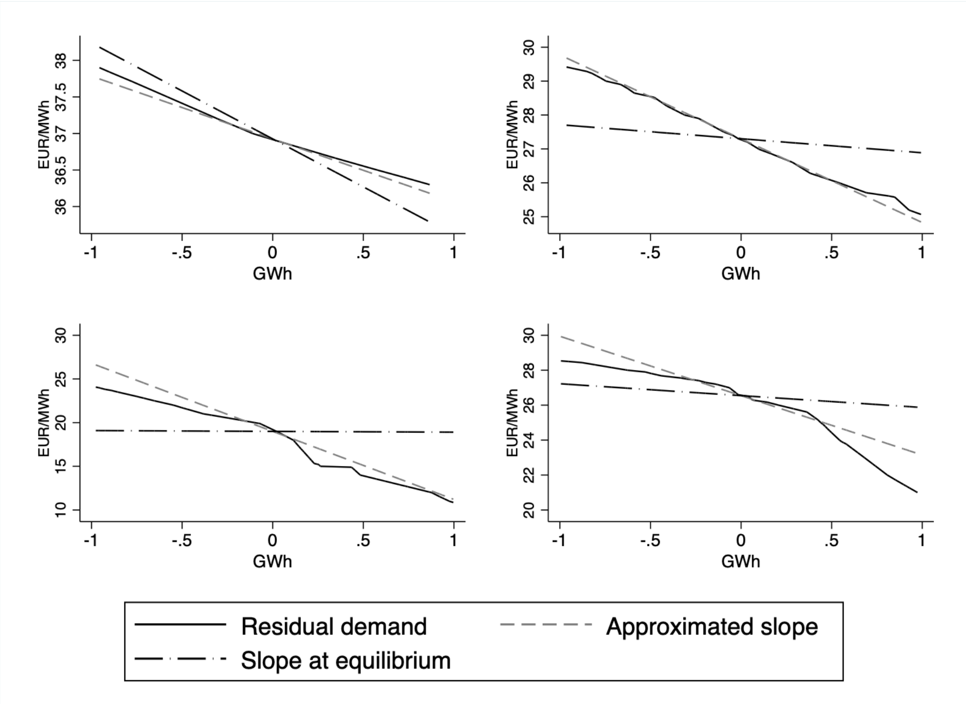
Note: Placebo estimates of the DiD specification (4) in Table 4 when varying the year of treatment between 1996-2010.

Figure A8: Monthly googling frequency for “kärnkraft”



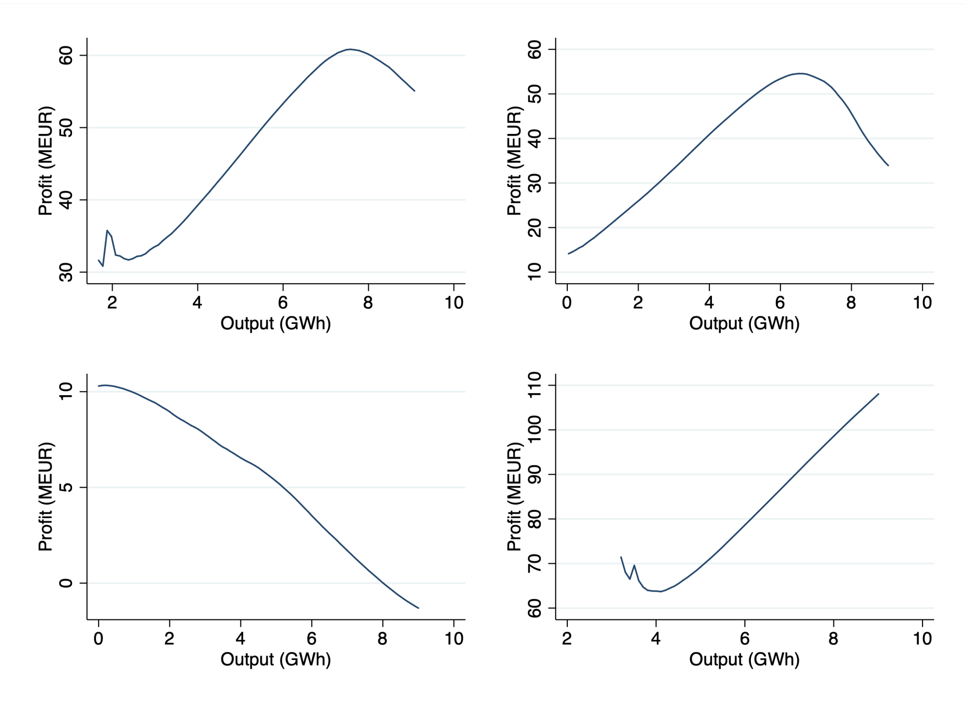
Note: Monthly googling frequency for “kärnkraft” (nuclear power) within Sweden. Winter months are shaded in grey. Figures have been normalized by dividing with the yearly mean.

Figure A9: Residual demand functions and slopes around the clearing point



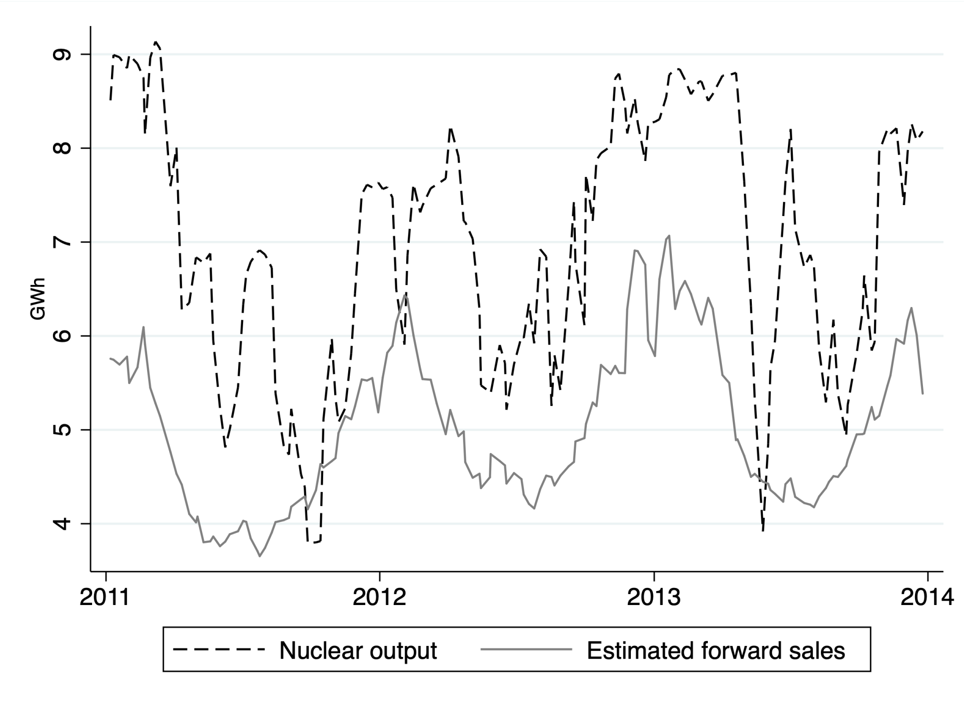
Note: Residual demand functions, the instantaneous slope just at the market clearing, as well as the approximated slope within a quantity window of 0.5 GWh on each side of the clearing point.

Figure A10: Examples of profit functions



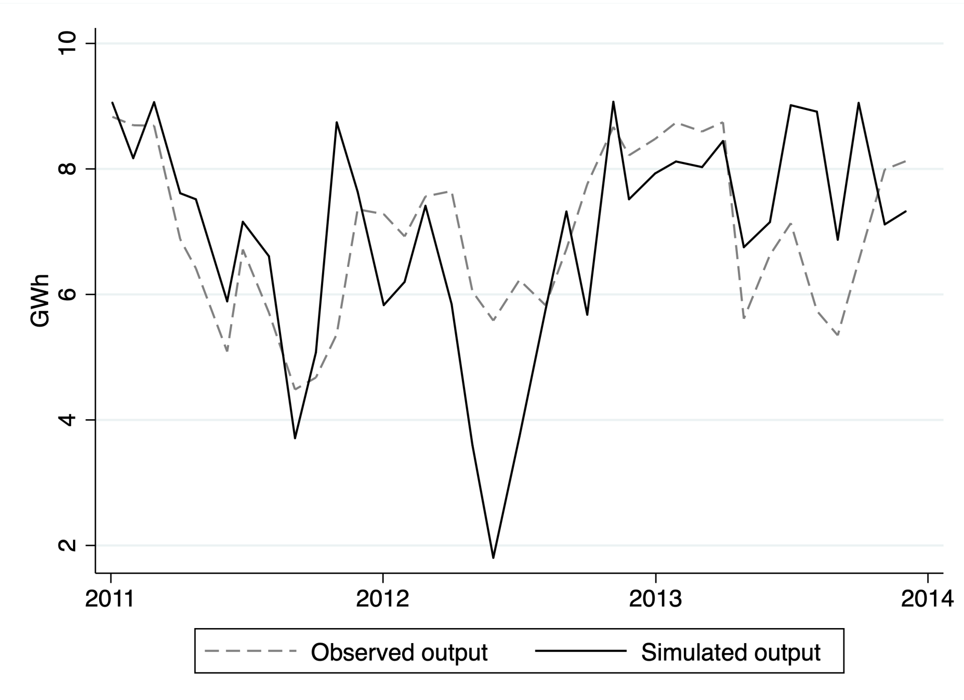
Note: Examples of weekly profit functions for Vattenfall.

Figure A11: Estimated forward sales



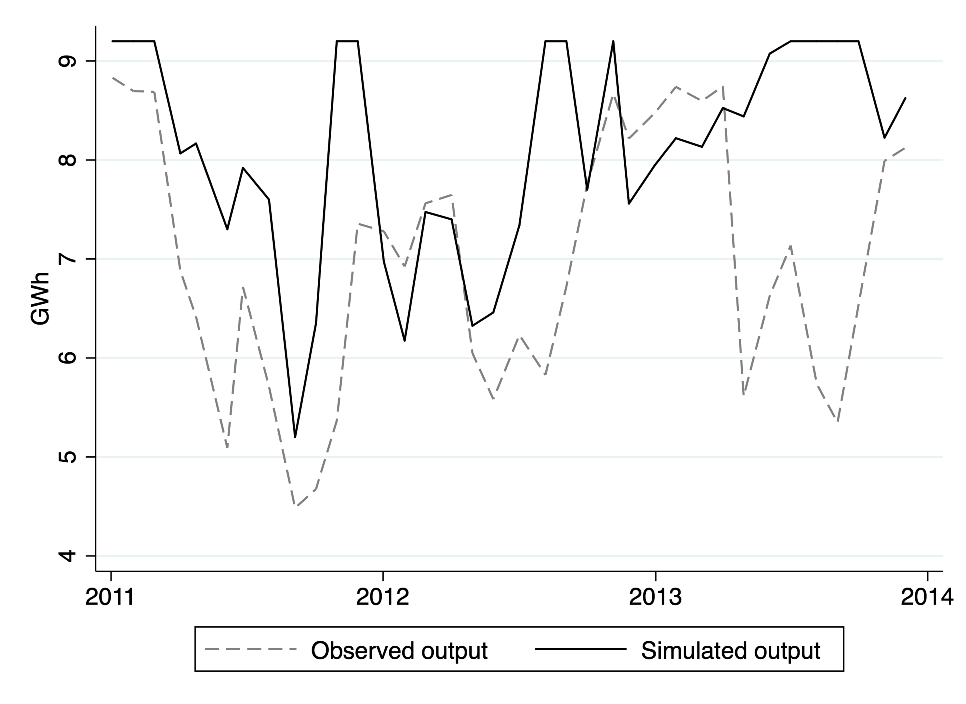
Note: Estimated forward sales under the divested solution (solid line) and observed nuclear output (dashed line).

Figure A12: Collusion, monthly output



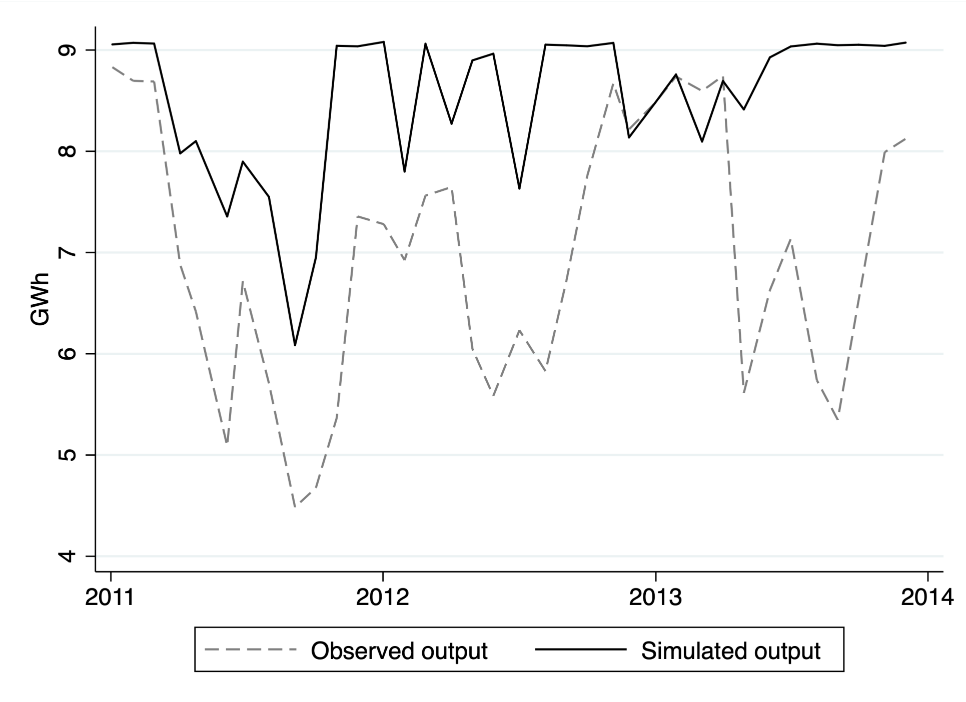
Note: Simulated output (solid line) and observed output (dashed line) given collusive behavior.

Figure A13: Cournot, monthly output



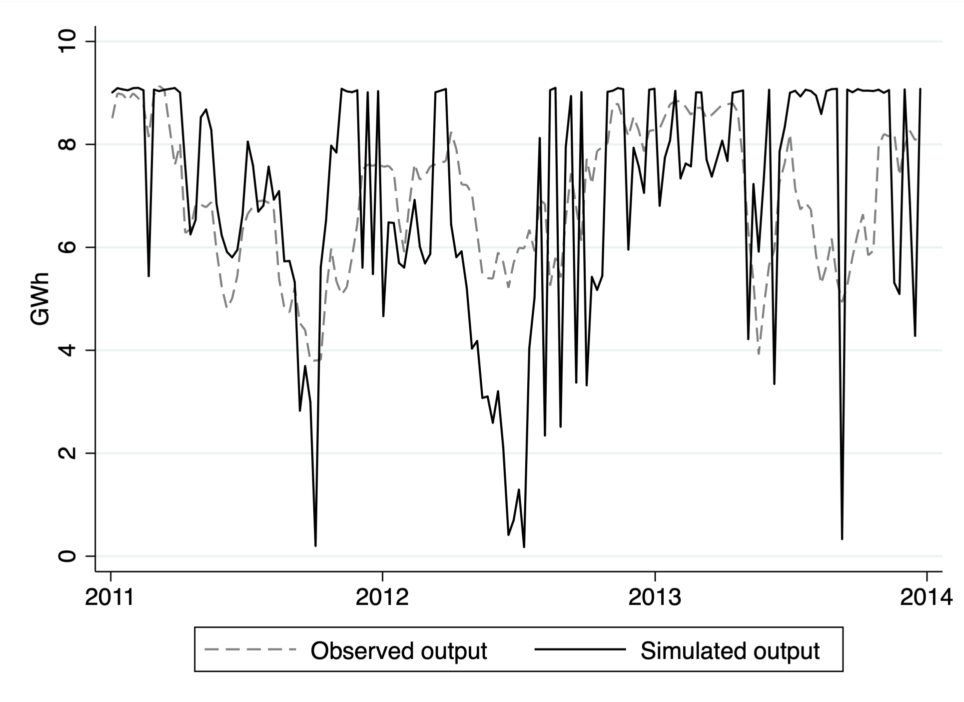
Note: Simulated output (solid line) and observed output (dashed line) given Cournot competition.

Figure A14: Divested solution, monthly output



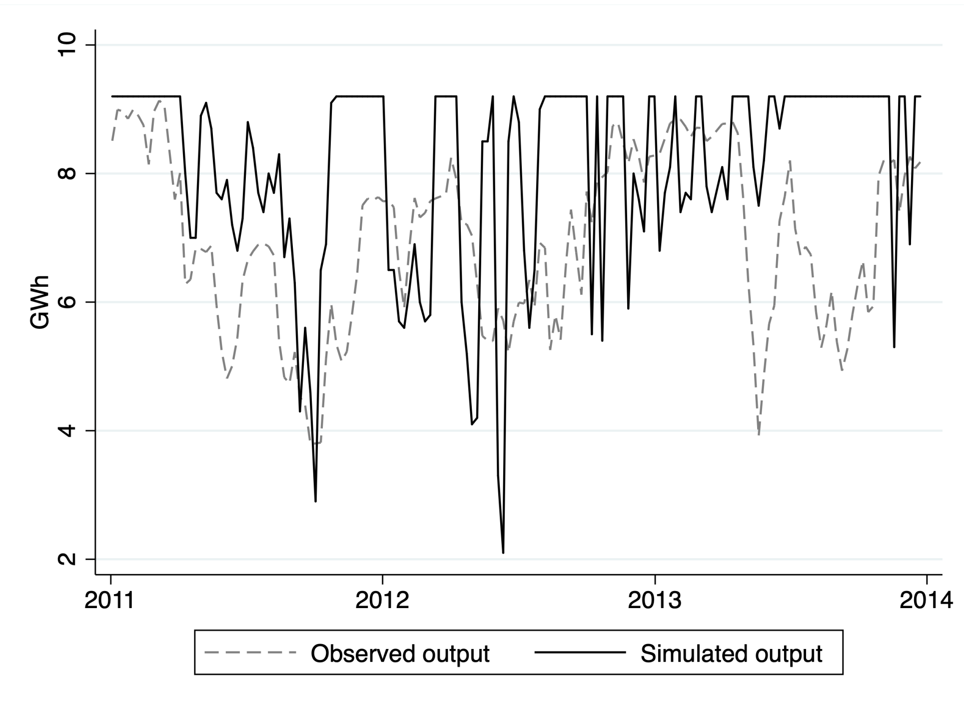
Note: Simulated output (solid line) and observed output (dashed line) under the divested solution.

Figure A15: Collusion, weekly output



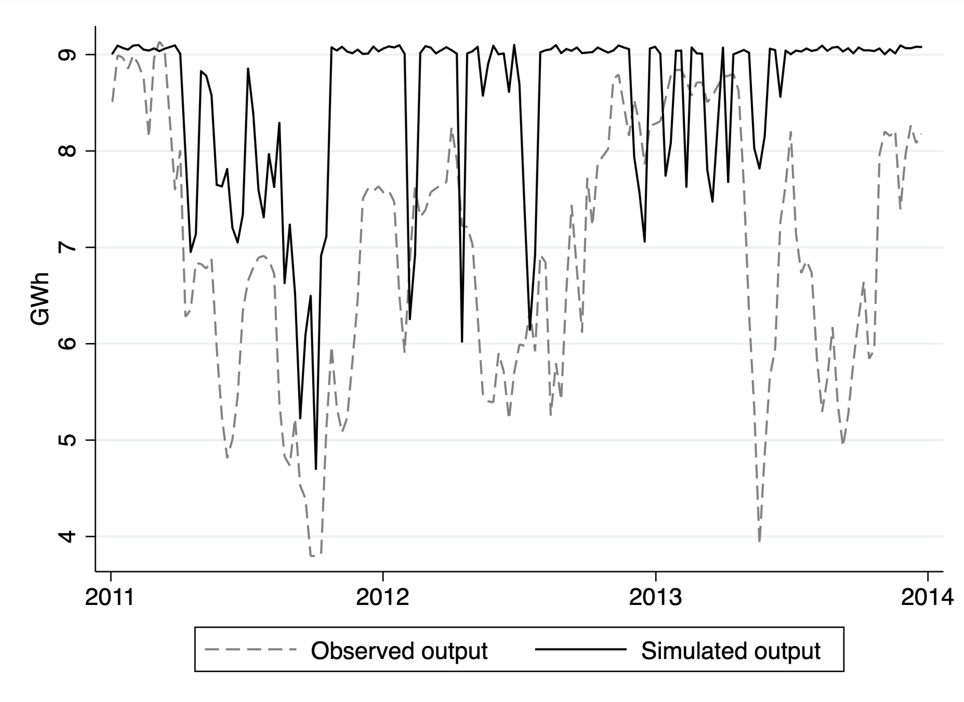
Note: Simulated output (solid line) and observed output (dashed line) given collusive behavior.

Figure A16: Cournot, weekly output



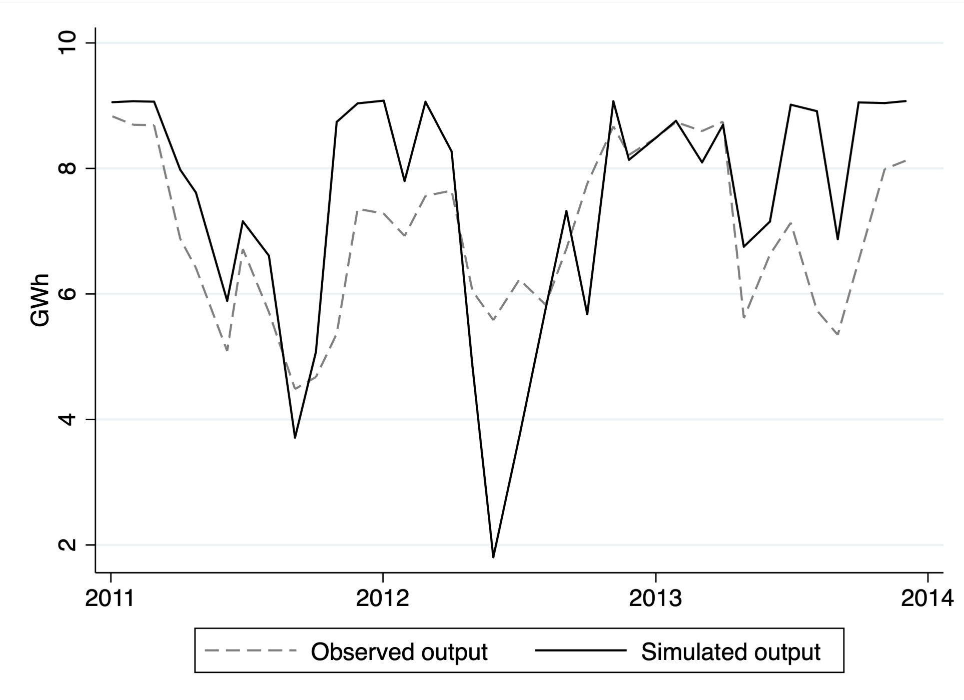
Note: Simulated output (solid line) and observed output (dashed line) given Cournot competition.

Figure A17: Divested solution, weekly output



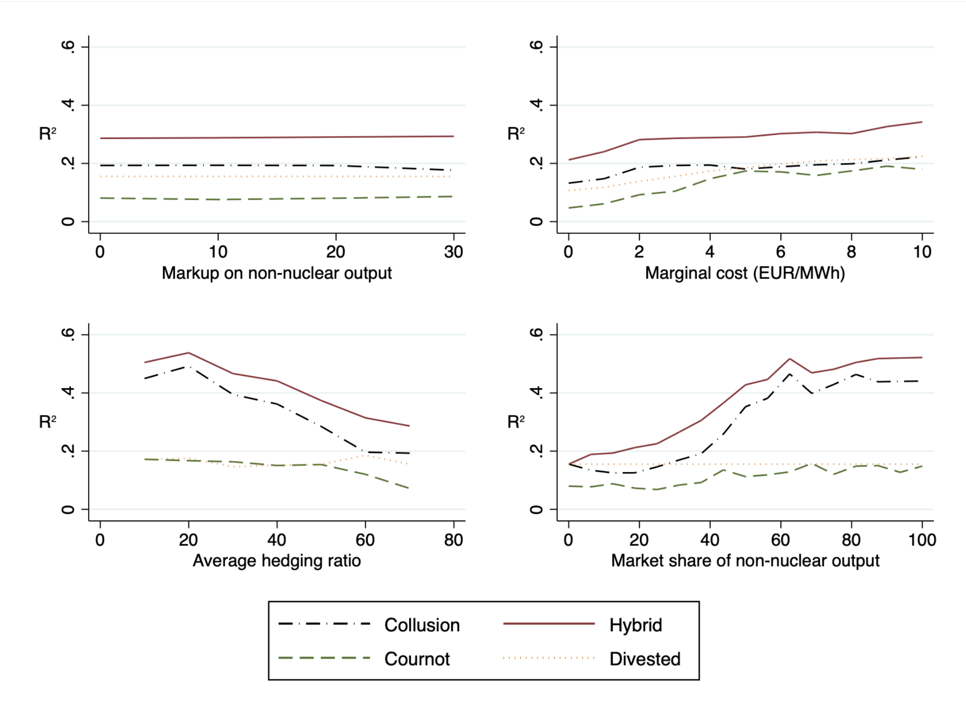
Note: Simulated output (solid line) and observed output (dashed line) given the divested solution.

Figure A18: Hybrid solution, monthly output



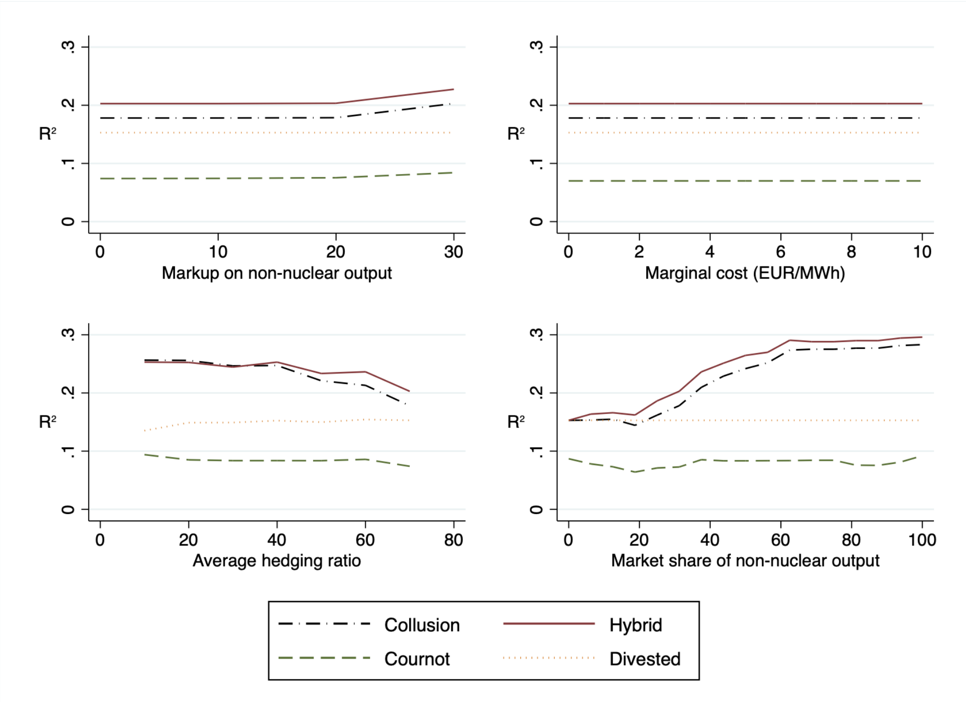
Note: Simulated output (solid line) and observed output (dashed line) given the hybrid model.

Figure A19: Sensitivity static specification



Note: R^2 as a function of parameter values when regressing observed output on simulated output according to eq. (11) under the static specification. Markups, hedging ratios, and market shares are in percent. Marginal cost is in EUR/MWh.

Figure A20: Sensitivity dynamic specification



Note: R^2 as a function of parameter values when regressing observed output on simulated output according to eq. (11) under the dynamic specification. Markups, hedging ratios, and market shares are in percent. Marginal cost is in EUR/MWh.