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Working Paper

Market power and joint ownership: Evidence from nuclear plants in Sweden

IFN Working Paper, No. 1113

Provided in Cooperation with:

Research Institute of Industrial Economics (IFN), Stockholm

Suggested Citation: Lundin, Erik (2016) : Market power and joint ownership: Evidence from nuclear plants in Sweden, IFN Working Paper, No. 1113, Research Institute of Industrial Economics (IFN), Stockholm

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IFN Working Paper No. 1113, 2016

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

Erik Lundin

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

Erik Lundin*

February 25, 2016.

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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 the variation in output, I formulate a model of intertemporal choice in which firms choose how to allocate a given amount of maintenance within each year. Using data on production and bidding curves on the day-ahead market, I test the model against data given three behavioral assumptions: Unilateral profit maximization; joint profit maximization; and a social planner. Modeling for joint profit maximization best matches data, indicating that joint ownership has facilitated coordination of maintenance decisions. Terminating the joint ownership and modeling for unilateral profit maximization would lead to a 5 percent decrease in prices and a 6 percent decrease in system production costs. I identify positive supply shocks in the form of inflow to the hydro power reservoirs as important determinants of the incentives to exercise market power. Therefore, the mechanisms discussed in this paper should be of relevance also in other electricity markets where the share of intermittent production is increasing. As a motivation for the structural exercise, I use a difference-in-differences estimator to identify a shift in the allocation of maintenance towards the winter season (when demand and prices are peaking) at the time of the introduction of the joint ownership. This is in line with the results from the structural model, as the ability to influence the price is also higher during the winter season.

JEL-Classification: D22, D43, D44, D92

Keywords: Joint ownership, electricity, nuclear, maintenance, collusion.

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1 Introduction

Joint ownerships are common in many markets. They may take the form of e.g. joint ventures, partial mergers and acquisitions, or joint ownership of production sites. Markets in which joint ownership has been studied include the automobile sectors in the US and Japan ([Alley, 1997](#)), the US airline industry ([Azar et al., 2015](#)), the US cellphone industry ([Parker and Röller, 1997](#)) US offshore oil tracts ([Kenneth Hendricks, 1992](#)), and the Dutch banking sector ([Dietzenbacher et al., 2000](#)). In electricity markets, joint ownership arrangements are also frequent. For example, 40% of all U.S. power plants are jointly owned, including nuclear plants ([US Energy Information Administration, 2014](#)).

A number of potential efficiencies may motivate such links, such as technological complementarities, risk sharing, or cooperation on R&D. However, there are at least two channels by which joint ownership has anticompetitive 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 of the unilateral incentives to act competitively ([Reynolds and Snapp, 1986](#)). The reason 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.

Although the theoretical literature is rich in describing the various channels by which joint ownership affects competition, empirical evidence is sparse. A likely reason is that disentangling the collusive- and unilateral outcomes in a setting with joint ownership is challenging, and often requires the researcher to make strong parametric assumptions. I overcome these challenges by studying the data rich environment of the Nordic electricity market where data on supply- and demand functions and production is readily available. The data enables me to compute the residual demand functions facing each plant and let firms choose a best-response given that residual demand function. Similar approaches have previously been used to measure market power in electricity markets (see e.g. [Borenstein et al. \(2002\)](#) and [Wolfram \(1999\)](#)). By contrast, as documented below, previous studies

on joint ownership have relied on a conjectural variations approach following the work of [Gollop and Roberts \(1979\)](#). The conjectural variations approach has been criticized to be a poor predictor of market power by e.g. [Corts \(1999\)](#) and [Kim and Knittel \(2006\)](#), especially in dynamic settings.

The study makes several contributions. To the best of my knowledge, it is the first study to empirically distinguish between the unilateral and collusive outcomes in a setting with joint ownership of specific production plants. The methodology is distinct from previous studies on joint ownership as I do not rely on a conjectural variations framework approach to identify firm conduct. It is also the first study to model plant maintenance as an intertemporal choice in a strategic setting.

The use of maintenance to disguise the exercise of market power has previously been discussed in the context of e.g. the British and Californian wholesale markets ([Wolak and Patrick, 2001](#); [Borenstein et al., 2002](#)). A deeper understanding of the strategic aspect of maintenance scheduling is therefore of general interest. Specifically, I consider the behavior of three firms owning shares in three Swedish nuclear plants. Sweden is part of the Nordic electricity market, which has the largest day-ahead market in Europe. It is about half the size of the *Pennsylvania-New Jersey-Maryland* market (which is the largest wholesale market in the world). Using publicly available detailed information about nuclear outages I identify maintenance as the primary reason for the reductions in nuclear output. I then formulate a model of intertemporal choice in which firms decide how to allocate output within each year, assuming that yearly output of each plant cannot exceed its observed output. Using hourly production and bidding data from the day-ahead market during 2011-2013 I simulate plant output given three behavioral assumptions: Joint profit maximization; unilateral best-response (in which output is determined by the majority shareholder of each plant); and a social planner. I find that the model of joint profit maximization matches data best, thus concluding that joint ownership appears to have facilitated coordination of maintenance decisions. Compared to the model of joint profit maximization, I find that prices are 5 and 6 percent lower under the unilateral best-response and the social planner models respectively. As the optimality condition of a competitive firm states that output should be allocated to equalize prices across periods, I also find that more competitive behavior is associated with less price volatility.

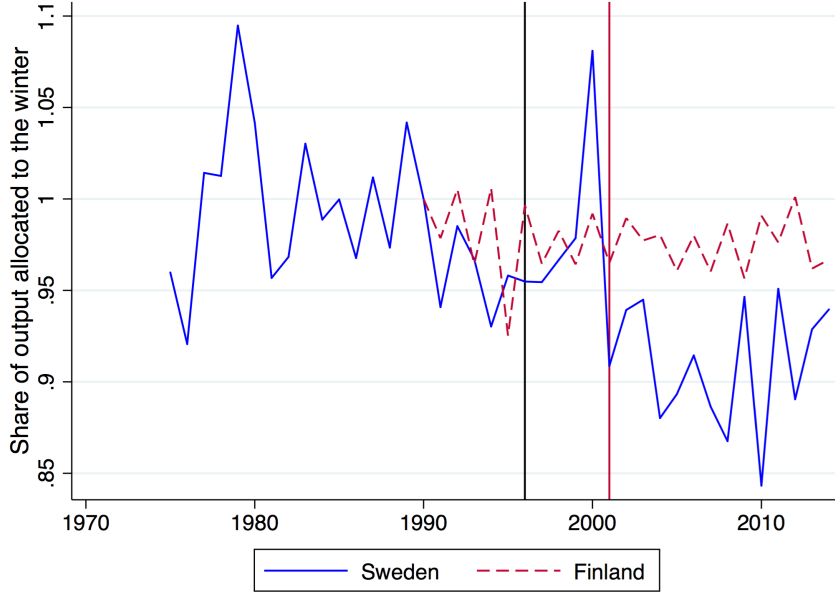
I then consider a counterfactual in which the joint ownership is dissolved, and firms own one plant each. Prices then drop by 3 percent compared to the model of joint profit maximization, illustrating that there would still exist some incentives to exert unilateral market power even if joint ownership would be terminated.

Noting that capacity factors ¹ of Swedish nuclear plants are relatively low by international standards (Swedish capacity factors were below 80 percent throughout the sample period, compared to above 90 percent for Finnish and American plants of the same vintage), I then allow each plant to operate at a capacity factor of up to 90 percent each year. However, under the model of joint profit maximization firms only expand aggregate output slightly above observed levels, i.e. the capacity factor constraint does not bind. Conversely, it is binding under the more competitive models. Hence, the price effect of introducing more competitive behavior is now greater due to the expansion of output, with price drops of 9 and 11 percent under unilateral best-response and the social planner models respectively. If terminating the joint ownership and removing the capacity factor constraint completely, unilateral incentives to exert market power disappear and plants are almost always operated at full capacity. In other words, while the intertemporal variation in marginal revenues creates incentives to exert market power when the capacity factor constraint is binding, these incentives disappear when output decisions depend on the static relationship between marginal cost and marginal revenue only.

Sweden deregulated its electricity market in 1996, forming the world's first multinational wholesale market for electricity together with Finland, Norway and Denmark. A series of M&A:s around the turn of the century resulted in a concentration of the ownership structure, and the nuclear plants (accounting for about half of Swedish electricity output) became jointly owned by three large firms. In 2001 nuclear output started to shift away from the winter season. In the Nordic region, electricity demand and prices are peaking during the winter due to the demand for heating, thus creating incentives for competitive firms to allocate as much output as possible to the winter. At the same time, the ability to influence the price is also higher during the winter season, since the system is often capacity constrained and it is more likely that firms are pivotal. Figure 1 depicts the

¹The capacity factor is the ratio of the electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous full power operation during the same period.

Figure 1: Share of yearly nuclear output allocated to the winter season 1990-2014

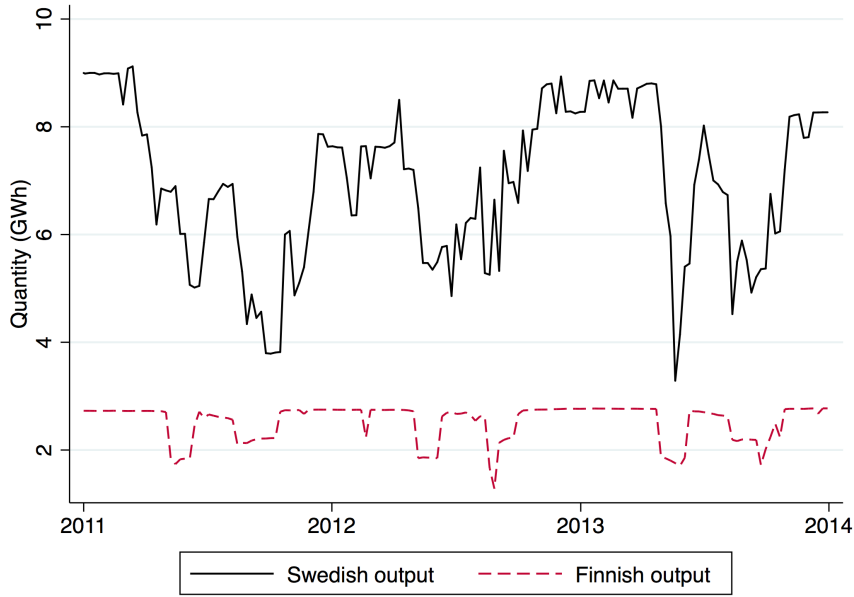


Note: this figure depicts the share of output allocated to the winter season (November-March) during 1990-2014, using 1990 as a reference year. Finnish data is only available from 1990. Finnish capacity factors increased somewhat during the sample period, while Swedish capacity factors remained roughly constant. Vertical lines are at the time of Swedish deregulation (1996) and at the introduction of the joint ownership (2001).

share of yearly output allocated to the winter season (i.e. November-March) during 1990-2014. By comparison, the corresponding graph for Finnish nuclear plants (that did not experience a change in the ownership structure) is depicted in the same figure, from which it is clear that the allocation of output has remained more stable. The first vertical line in the figure is at the time of Swedish deregulation (1996), and the second line is at the time of the introduction of the new ownership structure (2001). The figure has been constructed using monthly data on country level nuclear output, and the raw data is depicted in Figures A1 and A2. Even though Sweden and Finland sometimes face different prices due to transmission constraints, the price correlation is above 0.8. Hence, economic incentives how to allocate output are in practice identical for competitive firms operating within the region. To illustrate the change in allocation of Swedish nuclear output, I estimate the difference-in-differences model

$$q_{ct}^{winter} = \gamma_c + \lambda_t + \delta D_{ct} + \epsilon_{ct} \quad (1)$$

Figure 2: Swedish and Finnish nuclear production 2011-2013



Note: This figure depicts aggregate weekly nuclear production in Sweden and Finland 2011-2014.

Where q_{ct}^{winter} is the percentage of output allocated to the winter season, γ_c is a country fixed-effect, and λ_t is a dummy variable indicating the time of treatment. The treatment effect is captured by δ , i.e. D_{ct} is an indicator variable taking the value one for all Swedish observations after 2001. It is important to note that the capacity factors of Swedish nuclear plants did not increase during the time of analysis. If that would have been the case, a decrease in the dependent variable could have been achieved by increasing output during the summer season, in which case the interpretation of δ would be different. Results are summarized in Table 1, showing that the proportion of output allocated to the winter season decreased by 3.8 percentage points (or equivalently 25 percent) at the time of introduction of the current ownership structure ². A closer look at the weekly load profiles during the years in which detailed data is available (2011-2013) also reveals that within-year output is more volatile in Sweden than Finland. This is illustrated in Figure 2, from which it is evident that Finnish output is concentrated to the winter season, while the Swedish plants experience several "dips" in output during each year. This motivates a further examination if output decisions have been determined by strategic incentives,

²Another 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 (Barsebäck 1). To account for the fact that the shutdown may have affected the results, I re-estimated the model by assuming that Barsebäck 1 produced all its output during the winter season, with similar results.

Table 1: Dependent variable: Share of output allocated to the winter season.

Coefficient	(1)
Treatment effect ($\hat{\delta}$)	-3.8*** (0.62)
Number of observations	50

Note: Diff-in-diff estimate comparing the share of nuclear output allocated to the winter season (November-March) in Sweden and Finland. The unit of measurement is percentage. Standard errors in parentheses. * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$

and if so, to what extent the current ownership structure may have helped to shape these incentives.

The rest of this paper is structured as follows: In Section 2, I review the related literature. In section 3, I discuss the institutional background and data. In section 4, I perform a non-structural econometric test of market power by regressing nuclear output on the ability to influence the wholesale price using an IV estimator. In this section I also discuss the importance of inflow to the hydro power reservoirs for the ability to exercise market power. I present the structural model in section 5. Section 6 presents the results and discusses welfare effects. Section 7 concludes.

2 Related literature

Following [Reynolds and Snapp \(1986\)](#), [Farrell and Shapiro \(1990\)](#) analyze a similar setting of joint ownership, but where the marginal cost is a decreasing function of each firm's capital stock. The welfare implications then become less obvious. For example, if a firm with a small capital stock increases its holdings of a rival in which it previously had no financial interest, welfare may rise: As the smaller firm restricts output, the larger firms in the industry will expand output. Since larger firms have lower costs, price will decrease and welfare will increase. [Malueg \(1992\)](#) contrasts with the two previous studies by exploring an infinitely repeated game, revealing that tacit collusion may actually be harder to sustain under joint ownership. The reason is that even if joint ownership reduces the gain from cheating, it also softens the punishment that would follow cheating. The

first effect makes collusion more likely; the second effect makes collusion less likely. The net result is ambiguous and depends on the shape of the demand function.

Although the theoretical literature has been successful in describing the competitive effects of joint ownership, empirical evidence is sparse and the few existing studies rely on rather parameterized frameworks: [Parker and Röller \(1997\)](#) study the U.S. cell phone industry, concluding that joint ownership of operating licenses has contributed to market outcomes that often lie closer to a collusive- than a non-collusive equilibrium. In 22% of all U.S. markets, the equilibrium is found to equal the monopoly price. [Alley \(1997\)](#) studies the joint ownership in the Japanese- as well as the US automobile industry. He develops a conjectural variations approach following the work of [Clarke and Davies \(1982\)](#) to estimate a parameter reflecting the level of collusion. Although he finds signs of collusion, similar parameter results are found also without taking joint ownership into account, indicating that the unilateral incentives to reduce output due to joint ownership may have been limited. [Dietzenbacher et al. \(2000\)](#) examines the Dutch banking sector where they allow for indirect shareholdings (i.e. if firm A owns shares in firm B and firm B owns shares in firm C, firm A holds an indirect share in firm C). Using shareholding data and accounting numbers of output values and profits (which allows for calculation of price-cost margins), they fit a structural model and find that the observed price-cost margins are at least 8% higher than they would have been without joint ownership.

Another related strand of literature studies the use of market power in the Nordic electricity market. [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. [Amundsen and Bergman \(2000\)](#) examine how an increased wave of mergers and partial acquisitions may affect the unilateral incentives to behave competitively, concluding that even small increases in the ownership of competing firms could have anticompetitive effects. [Kauppi and Liski \(2008\)](#) construct a simulation model of hydro production in the Nordic market during 2000-2005, showing that a model where one strategic producer controls 30% of the hydro capacity fits data better than a model where hydro producers behave competitively. [Damsgaard \(2007\)](#) presents another simulation model that is tested for a sample of periods during 2002-2006, but without finding any conclusive evidence of market power other than within very limited time periods.

Fogelberg and Lazarczyk (2014) study the use of capacity withholding through “voluntary’ production failures to exert market power in the Nordic market during 2011-2012. They find indications of strategic withholding of fossil plants, but not nuclear or hydro. However, their analysis relies on a different set of identifying assumptions than than the analysis in this study, as they do not make use of bidding data.

Studies of unilateral market power in other electricity markets are frequent. Some well-known examples from the British market are Green and Newbery (1992), Wolfram (1999) and Wolak and Patrick (2001), all finding evidence of market power as a contributing factor to market outcomes. Borenstein et al. (2002) and Wolak (2003) study the Californian market during 1998-2000, finding market power to be an important factor in explaining the high wholesale prices during the Californian electricity crisis in 2000. McRae and Wolak (2014) studies the New Zealand electricity market and finds that all of the four largest firms exercise market power on a systematic basis. Studies of collusion in electricity markets are less frequent: Puller (2007) examines the Californian electricity market, finding that the five large firms were able to raise prices slightly above the unilateral market-power levels in 2000, but fell short of colluding on the joint monopoly price. Fabra and Toro (2005) study the Spanish electricity market during 1998, finding indications of times with both collusion and price wars.

3 Institutional background and data

3.1 Institutional background

The Nordic electricity markets were deregulated in during the 1990’s, creating a common market for Norway, Denmark, Sweden and Finland. It now includes also Estonia, Latvia and Lithuania. The main trading platform for physical energy is the day-ahead market, in which more than 80% 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, i.e. there are between 12-36 hours between submission of the bids and actual physical delivery. Each participant submits supply- or demand functions of up to 62 price steps, with a price

ceiling of 2000 EUR. A unique feature of the Nordic market is that bidders also commit to bids that are linear combinations of adjacent price-quantity pairs ³. The auctioneer can therefore clear the market where supply meets demand, through linear interpolation of the aggregated offer curves. This price is called the system price. Figure 3 shows an example of the aggregated supply- and demand curves. The nuclear producers sell almost all their output on the day-ahead market, and any obligations to deliver electricity through future 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 1 EUR and the day-ahead price is realized at 0.9 EUR/MWh, the producer will receive 0.1 EUR in cash from the buyer of the contract. Although it is beyond the scope of this paper to consider the optimal behavior of the firms given their financial positions it is worth to note that the presence of forward obligations should have a positive effect on the 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) will also have the effect of increasing competition in the day-ahead market since retail obligations are often very similar to forward contracts. See [Wolak \(2007\)](#) for an empirical examination of the competitive effects of forward contracting in the Australian electricity market, and [Bushnell et al. \(2008\)](#) for the competitive effects of vertical integration in three electricity markets in the US.

The market is fairly concentrated, and yearly market shares do not display much variation during the sample period. Including nuclear production, in 2012 the firm with the largest share of total production was the Swedish state-owned producer Vattenfall (19%) followed by Norwegian state-owned Statkraft (14%). The third largest producer was Fortum (12%) in which the Finnish state is the majority owner, followed by the German private energy

³In 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, block bids refers to more than one hour, and second, a bid is either accepted or not accepted as a whole. On average, 5% and 1% respectively of the accepted sell- and buy volumes in the data 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. For simplicity I therefore assume that block bids are inelastic, i.e. that they enter the market at zero cost. Correspondingly, I only have information about the volume of net exports and not at which price they were bid in. On average, 6% of the traded volume comes from net exports. Analogously, I also let net exports enter the auction as inelastic bids. During 2015 the price ceiling for both block- and regular bids was raised to 3000 EUR.

Table 2: Production mix in the Nordic region

Production type	Percentage of production
Hydro	52
Thermal (non-nuclear)	21
Swedish nuclear	15
Finnish nuclear	6
Wind	6

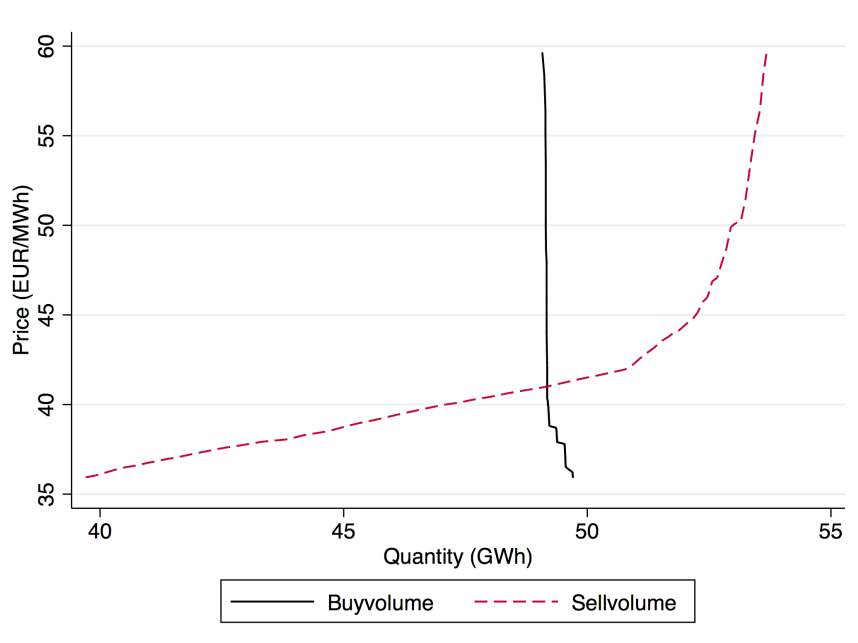
Note: This table depicts market shares by fuel type for the whole Nordic market during 2011-2013.

Table 3: Ownership shares by plant and company

Power plant	Total capacity (GW)	Number of reactors	Vattenfall	E.ON	Fortum
Ringhals	3.7	4	70	30	0
Forsmark	3.1	3	66	10	22
Oskarshamn	2.3	3	0	55	45
Counterfactual					
Ringhals	3.7	4	100	0	0
Forsmark	3.1	3	0	0	100
Oskarshamn	2.3	3	0	100	0

Note: Ownership structure of Swedish nuclear plants 2002-present. Majority ownership shares in **bold**. The ownership structure in the counterfactual scenario is presented in the bottom three rows.

Figure 3: Aggregate supply and demand



Note: This figure depicts aggregate supply- and demand functions on the Nordic day-ahead market during 2-3 pm January 19 2013.

consortium E.ON (7%). There are five nuclear plants in the Nordic system: Three are located in Sweden and two in Finland. Vattenfall, Fortum and E.ON jointly own the Swedish plants according to the ownership structure depicted in Table 3. The bottom three rows depict the ownership structure in the counterfactual scenario in which the joint ownership is terminated. The nuclear plants are organized as limited liability companies, and the majority owner in each plant also has the operational responsibility for that plant ([Energy Market Inspectorate, 2012](#)). E.ON is the only company that owns shares in all three plants. E.ON is also the majority owner of the Oskarshamn nuclear plant, and Vattenfall is the majority owner of Ringhals and Forsmark. Fortum owns shares in both Oskarshamn and Ringhals ⁴. The current ownership structure of the 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 the first step to phase out the Swedish reactors. Since Barsebäck was fully 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 government. In 2005, the remaining reactor Barsebäck 2 (also with a capacity of 0.6 GW) was shut down. 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 Sydkraft. In 2000 Fortum acquired the Swedish firm Stora Kraft, thereby gaining ownership in both Forsmark and Oskarshamn. For further details about these M&As, see [Energy Market Inspectorate \(2006\)](#). Nuclear production represents about half of the production portfolio of the owners, and hydropower constitutes the major share of the remaining production. Each firm also owns a number of plants primarily used for district heating that generates electricity as a by-product (i.e. combined heat- and power), and a number of wind farms. Vattenfall and Fortum also own one conventional peak load thermal plant each. For a complete list of the owners' generation plants, see [Vattenfall \(2015\)](#); [E.ON \(2015\)](#); [Fortum \(2015\)](#). The production mix for the whole market is depicted in Table 2.

⁴Oskarshamn has three reactors, all of which are boiling water reactors. The reactors began operation in 1972, 1974 and 1985. 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 is the newest plant, and has three boiling water reactors that began operation in 1980, 1981 and 1985 respectively. For further information about the technical characteristics of the plants, see [Swedish Radiation Safety Authority \(2014\)](#).

A unique feature of the Nordic power market is that information about maintenance and failures that involves outages above 100 MW have to be reported in the form of so-called “Urgent Market Messages” that are sent to an online database. Figure A3 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 time for a scheduled maintenance, 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 reported during the sample period, with an average of 4.5 messages per event. 85% of the outages (measured in GWh) are due 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. Factually, 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. However, at least on a weekly basis 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%. See Figure A5 and A6 for a graphical illustration of how well aggregate nuclear output can be predicted using only the Urgent Market Messages. Although I do not make use of the Urgent Market Messages explicitly in the simulations, I may conjecture that other market participants have good information about nuclear output at the time of bidding in the day-ahead market, and

that the majority of all capacity reductions are not due to exogenous events (such as unforeseen production failures), but can be attributed to planned maintenance.

Nordic nuclear producers are not unfamiliar with the exercise of market power. After an extended period of low wholesale prices around the year 2000 due to a large amount of inflow into the hydro reservoirs, nuclear production suddenly dropped unexpectedly in several of the plants. Attention was brought to the major shareholder of two of the plants, who later claimed that: *“Sometimes we reduced [nuclear] production when prices were above the variable cost...with the result that prices increased somewhat...but we never did it in agreement with the other co-owners”*⁵. In 2006 the Swedish Competition Authority investigated suspicions of coordinated reductions of nuclear production in the Swedish plants in order to raise prices. The authorities found 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 voluntarily interrupted by the time of the investigation and the authorities decided not to investigate the matter further. Since 2002 each owner has the right to a share of the available capacity in each plant (i.e. net of maintenance and other outages), proportional to its ownership share. Each owner then independently requests to the plant operation manager how much of that capacity it would like to use for production ([Nordic Competition Authorities, 2007](#)). During 2011-2013, all owners choose to use all capacity available, i.e. planned outages was the way owners controlled the level of output. Nevertheless, the Swedish government has continued to express concerns that nuclear producers are abusing their dominant positions, and in 2012 the producers were obliged to adopt a “Code of Conduct” ([Energy Market Inspectorate, 2012](#)) that explicitly states the type of information that nuclear producers are allowed to share. One type of information that may be shared is “All information that is relevant in order for the activity at the plant to be operated in a way that is: (i) secure; (ii) rational; and (iii) efficient”. Therefore, to the extent that maintenance decisions are relevant with regard to either of the points above they may be discussed freely among the owners in a way that does not by default infringe on antitrust legislation. In tandem with the Code of Conduct, the owners signed a regulatory agreement stating that the scheduled maintenance should be avoided during the winter period (November-March). However, similar to the formulation

⁵The quote is a transcript (freely translated from Swedish) from a radio interview with the head of production at the Swedish producer Vattenfall. For the whole interview, see [Radio Sweden \(2006\)](#).

in the Code of Conduct, maintenance may still be performed during the winter season if the owners determine that it is necessary due to safety reasons.

3.2 Data

I use two primary data sources in the main analysis (that spans between 2011-2013): Plant-specific hourly nuclear production has been compiled specifically for this study by the Swedish transmission system operator (“Svenska Kraftnät”). This production data is available from the author upon request. System supply- and demand curves, data on inflow to the hydro reservoirs, realized prices and quantities, Urgent Market Messages and the consumption prognosis have been downloaded from the Nordpool FTP-server and is subject to a subscription fee (Nordpool, 2015). Most Nordpool data is also available free-of-charge for manual downloads at the Nordpool downloads center (www.nordpoolspot.com/download-center/). Yearly market shares of the firms’ non-nuclear output have been collected from the market reports of the Nordic Energy Regulators (Nordreg, 2011, 2012, 2013). The monthly production data used in the diff-in-diff exercise in the introduction that spans between 1990-2014 is available for download at Statistics Sweden and Statistics Finland respectively (Statistics Sweden, 2015; Statistics Finland, 2015). In the comparison of trends in capacity factors of Swedish- vs. U.S. and other European reactors, all data is from the IAEA Power Reactor Information System (IAEA, 2015).

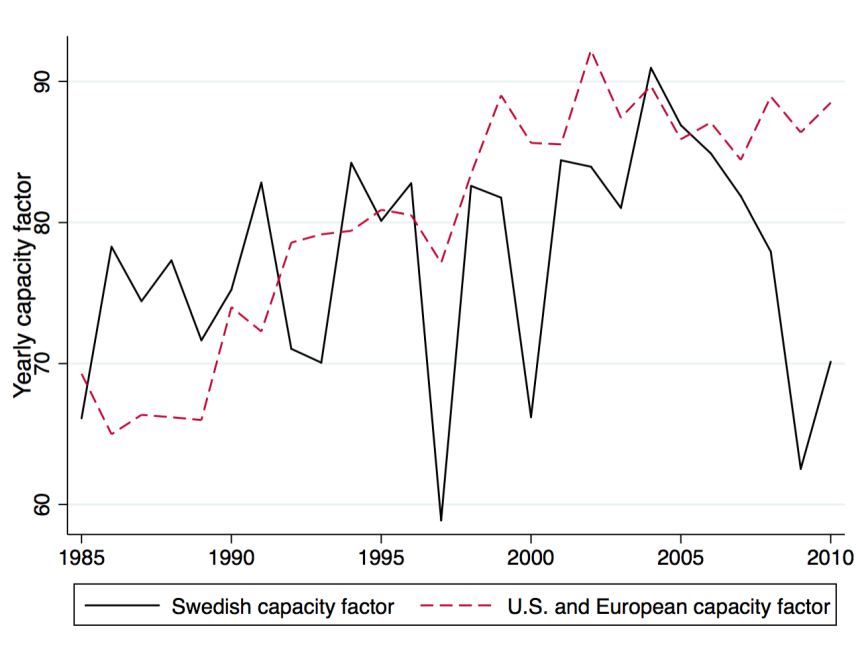
Table 4 summarizes the main observed variables. The mean system clearing price is 39 EUR/MWh. In absence of transmission constraints all participants face the system price. If there are bottlenecks in transmission the Nordic market may be divided into 15 different price zones depending on where the bottlenecks occur. The geographical borders of the price zones are illustrated in Figure A4. All Swedish nuclear plants are located within the same price zone (“SE3”) which follows the system price very closely (the correlation between the system price and the price in SE3 is 0.96). Therefore I use the system price as a proxy for the price received by the nuclear plants. The system supply- and demand curves contain around 600 price-quantity pairs each (firm-specific bid data is not available at present). As depicted in Figure 3, the entire demand function is usually highly inelastic

Table 4: Summary statistics of data used in the main analysis

Variable	Mean	St.dev	Min	Max
Observed system clearing quantity	35.94	7.27	19.89	58.16
Consumption prognosis	43.77	8.92	25.81	68.99
Reservoir inflow	23.99	17.93	2.48	98.54
Observed system clearing price	38.78	14.28	1.38	224.97
Production in Oskarshamn	1.52	0.56	0.00	2.36
Production in Ringhals	2.67	0.94	0.00	3.76
Production in Forsmark	2.79	0.55	0.97	3.30
Market share on day-ahead market (excluding Swedish nuclear)				
Vattenfall	13	3	11	17
E.ON	3	1	2	4
Fortum	11	0	11	12

Note: Clearing quantity, consumption prognosis, reservoir inflow and plant production are expressed in GWh/h. Prices are expressed in EUR/MWh. Market shares on the day-ahead market are expressed as percentages. The consumption prognosis is larger than the clearing quantity since some of the electricity consumed is not traded on the day-ahead market.

Figure 4: International trends in nuclear capacity factors



Note: This figure depicts capacity factors of Swedish vs. U.S. and other European nuclear reactors that are presently in operation. Only foreign reactors built before 1974 are included in the sample. Reactors that have been permanently shutdown are excluded. There are 41 foreign and 9 Swedish reactors included in total.

except at very low prices. The supply elasticity varies more: Nuclear- and hydro provide base load production, and are usually supplied at low prices. As demand increases, more thermal production will be dispatched and the supply curve becomes steeper. As a result, in peak load hours the supply elasticity is generally lower than in low peak hours. The average price during a peak hour is 30% higher than the average price during a low peak hour, which is comparable to the difference in prices during the winter- and summer periods. The consumption prognosis is determined at 11 am the day before delivery and is about 20% higher than the cleared day-ahead quantity, since all electricity consumed is not traded at the day-ahead market. Reservoir inflow (measured in GWh of potential electricity production) is about half of the consumption prognosis, consistent with the fact that hydro production represents about half of the production in the market.

Of all Swedish plants, Oskarshamn had the lowest capacity factor throughout the sample period (64%), followed by Ringhals (71%) and Forsmark (85%). The international trend towards increased nuclear capacity utilization has not taken place in Sweden. Figure 4 compares the trend in capacity factors of Swedish nuclear reactors with reactors in the U.S. and the rest of Europe (excluding the former Soviet Union). Since older reactors tend to have lower capacity factors than newer ones, all foreign reactors constructed after 1974 are excluded from the sample. One of the Swedish reactors was constructed in 1971, and is therefore also excluded (excluding foreign reactors built after 1971 would substantially reduce the sample). In other words, all Swedish reactors in the sample are of the same age or younger than the foreign ones (the mean construction year of a Swedish reactor in the sample is 1979, vs 1972 for the foreign reactors). Also, all plants that have been permanently shut down are excluded. It is clear that the positive trend in capacity factors among foreign reactors has not taken place in Sweden: Comparing the years before and after Swedish deregulation, the mean capacity factor of foreign plants increased from 73% to 87%, while the mean Swedish capacity factor is around 77% during both periods. One reason for the relatively low capacity factors may be due to the decision in 1980 (by referendum) to gradually phase out the nuclear plants, although the only plant that has in fact been shut down is Barsebäck. The decision may have lead owners to refrain from large-scale investments that would mitigate the need for frequent maintenance disruptions. However, in the present study I also examine the possibility that market power may have

mitigated incentives to keep capacity factors high.

4 A non-structural econometric test of market power

In this section I use a non-structural econometric framework to examine if nuclear output responds to the ability to exercise market power. As a measure of the ability to exercise market power I use the (absolute) slope of the inverse system residual demand function evaluated at the market clearing point. I define the system residual demand function as:

$$D_{res}^{sys}(p) = D(p) - S(p)$$

where $D(p)$ is the system demand function and $S(p)$ is the system supply function. The slope is then given by:

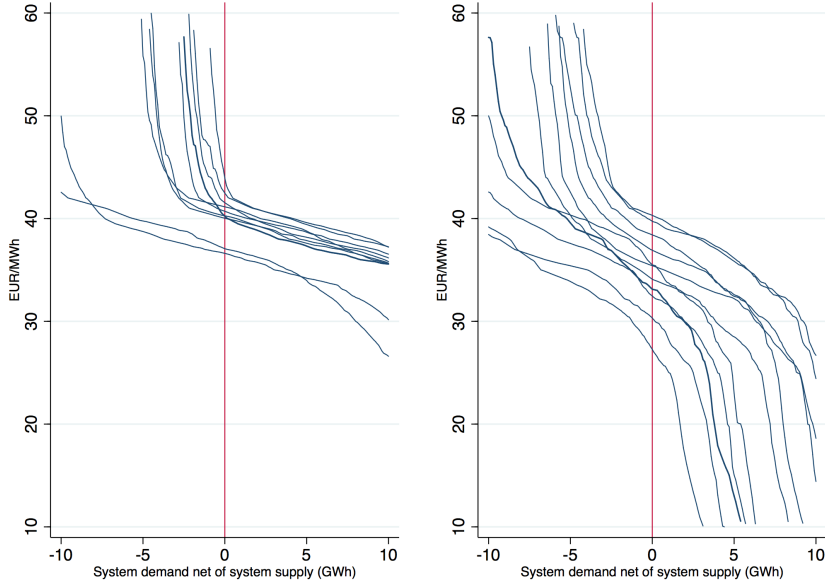
$$\left| \frac{\partial p(D_{res}^{sys})}{\partial D_{res}^{sys}} \right|$$

It is a measure of the price increase (in MWh/h) that would be the result of a one unit increase in inelastic supply (in GWh) by any firm in the market. Similar approaches have been used in previous work by e.g. [Reguant \(2014\)](#) and [McRae and Wolak \(2014\)](#). However, they observe firm-specific bids directly. Then it is possible to compute the residual demand function of firm i according to:

$$D_{res}^i(p) = D(p) - \sum_{j \neq i} S^j(p)$$

Although I approximate firm specific bids in the structural section below, for the moment I stick to a measure of market power that is identical across firms, as it imposes a minimal set of assumptions on individual firm bidding. Figure 5 depicts a sample of the system inverse residual demand functions during a month with high demand (February) as well as low demand (June) 2013 at 5 pm.

Figure 5: System residual demand functions in February and June



Note: This figure depicts random system residual demand functions (i.e. system demand minus system supply) in February (left diagram) and June (right diagram) 2013 at 5 pm.

I compute the slope by taking a quantity window of 0.5 GWh on each side of the market clearing point and interpolate prices at these points. The interpolation procedure is identical to the clearing algorithm used by Nordpool (apart from the treatment of blockbids). As a robustness test I also compute the slope by instead using a quantity window of 0.25 and 1 GWh respectively. The correlation between all slope measures are above 0.8, confirming that the size of the window is of less importance for how the slope is computed. The median value of the slope is 1 (the standard deviation is 9.3), meaning that a 1 GWh decrease in supply would increase the price by 1 EUR/MWh. If instead expressing the slope as an elasticity, i.e.

$$\left| \frac{\partial p(D_{res}^{sys})}{\partial D_{res}^{sys}} \right| \times \frac{q}{p}$$

Where q and p are market clearing quantity and price, the median value is still one, i.e. a percentage increase in supply will on average decrease the price by one percent.

Hydropower constitutes a large share of the production in the Nordic region (52%), and positive supply shocks in the form of inflow to the hydro reservoirs are important deter-

minants of the ability to exert market power. This relationship is illustrated in Figure 6, displaying a positive correlation between the median slope and the amount of reservoir inflow⁶. Inflow is an exogenous process where precipitation and melted snow flow into the reservoirs. It follows yearly cycles, and peak inflow is in April-June. During times of high inflow, hydro producers with limited storage possibilities are forced to produce to reduce the risk of overflowing. Førsund (2005) notes that in Norway (where 60% of the Nordic hydro production is located), reservoir capacity is concentrated to a small number of firms. Small hydropower firms tend to have less reservoir capacity, and 30% of Norwegian hydro production comes from run-of-the-river plants that do not have any storage possibilities at all. This opens up for dominant firms to exercise market power during periods when production constraints are binding. Since periods of high inflow occur during periods when consumption is relatively low, it is notable that the median residual demand function is steep during these periods. If nuclear- or other base load generation do not counteract the positive supply shock due to increased reservoir inflow, prices may become very low. Looking at Figure 5 we also see that the slope becomes very steep at low prices in June (right diagram). Conversely, in February (left diagram) the slope is only steep at high prices. Since nuclear producers have very limited access to other thermal base load generation than nuclear, allocating maintenance to exert market power during periods of high inflow is a natural strategy. Figure 7 depicts the relationship between nuclear output and reservoir inflow. The variables display a clear negative correlation (with a correlation coefficient of -0.7). Conversely, the price, which should be the best determinant of output in a competitive market, display a less pronounced covariation with nuclear output (with a correlation coefficient of 0.31).

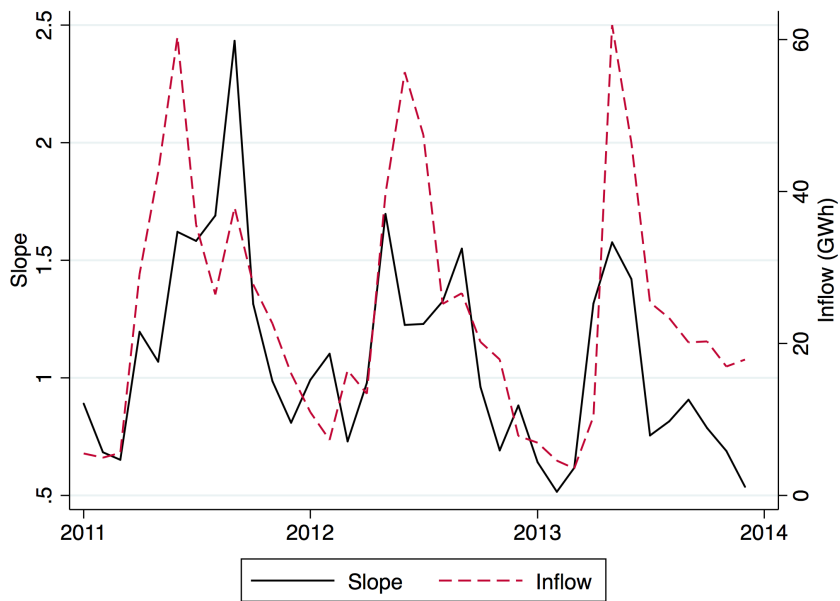
As a non-structural test of the determinants of nuclear output I estimate:

$$q_t^{nuc} = \alpha + \Theta slope_t + \beta price_t + \rho inflow_w + \mathbf{M}\gamma + \epsilon_t \quad (2)$$

Where q^{nuc} is nuclear output, $slope$ is the slope of the inverse residual demand function,

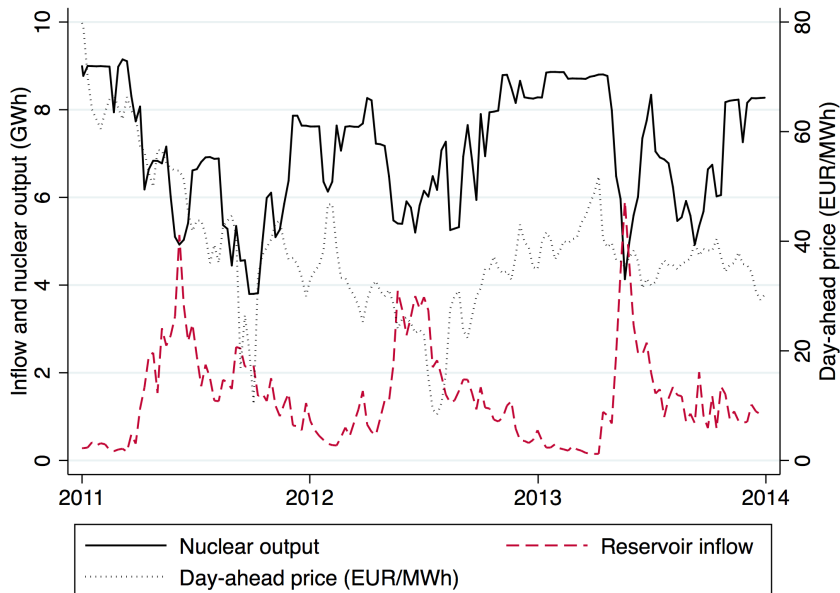
⁶Figure 6 depicts the monthly median slope and inflow. By contrast, Figure A7 depicts the same relationship but instead displaying the mean slope. The relationship is then reversed, with the highest slopes occurring during the winter season. In other words, although occasions of high demand will lead to extremely high slopes during short periods in the winter, reservoir inflow is a better determinant of the possibility to exercise market power when the system is not capacity constrained.

Figure 6: Reservoir inflow and slope of residual demand



Note: This figure depicts the median monthly reservoir inflow in Sweden and Norway, as well as the median slope of the system residual demand function.

Figure 7: Nuclear output and reservoir inflow



Note: This figure depicts weekly Swedish nuclear production, reservoir inflow in Sweden and Norway and day-ahead price. The inflow variable has been scaled by a factor of 0.06.

price is the day-ahead price, *inflow* is reservoir inflow, and \mathbf{M} is a vector of time fixed effects. Inflow is measured as the total amount of water (in GWh) flowing into the hydro reservoirs in Sweden and Norway. All variables are hourly, except for inflow that is only available on a weekly basis. The expected sign of Θ is negative if firms exercise market power. The expected sign of β is positive, as firms should be willing to supply more electricity when the price is high. The expected sign of ρ is negative. Both price and the slope may suffer from endogeneity: Price is endogenous since increased output drives down the price. The slope is endogenous since increased output will usually move the equilibrium to a less steep part of the residual demand function. Therefore I instrument the price and the slope using forecasted consumption the day before delivery and its square. The consumption forecast does not take price into account, and is thus exogenous with respect to the error term. Using forecasted consumption to instrument for price is common practice in the electricity literature, see e.g. [Kim and Knittel \(2006\)](#). The consumption forecast is from 11 am the day before delivery, and is a strong predictor of both the slope and the price. A potential violation of the exogeneity assumption could arise if production plans are known ex-ante, and consumers adjust their consumption plans accordingly. However, the consumption forecast is based on meteorological factors such as forecasted temperature and precipitation, and some macroeconomic variables of economic activity. Therefore, fine-tuned adjustments of consumption plans due to information about e.g. nuclear outages are not captured by the consumption forecast. Further, as depicted in Figure 3, demand is often almost perfectly inelastic around the market clearing point, emphasizing the exogeneity of the (short-term) demand with respect to price.

4.1 Results

Looking at Table 5, the slope coefficient Θ is negative in all specifications, which is consistent with the hypothesis that firms exert market power. Without controlling for reservoir inflow, in column (1) we see that a one standard deviation increase in the slope will lead to a reduction in output by 0.38 standard deviations (or approximately 8 % of mean nuclear output). After controlling for reservoir inflow in (2) the slope coefficient drops by half, confirming that reservoir inflow is a good determinant of the slope. Controlling for seasonal fixed effects (winter, spring, summer and fall) in (3) only changes the coefficient

slightly. The OLS estimate of Θ is almost identical to the corresponding IV estimate in (3). The price coefficient β is positive in all specifications. Without controlling for reservoir inflow, a one standard deviation increase in the price is associated with a 1.18 standard deviation increase in output. Similar to the slope variable, the price coefficient drops by half when controlling for inflow. However, contrary to the slope variable the price variable again drops by almost half when also including seasonal fixed effects. The OLS estimate of β is about $\frac{2}{3}$ of the IV estimate, indicating that the OLS estimate is biased downwards due to reverse causality. The magnitude of the inflow coefficient ρ is similar in all specifications, indicating that a standard deviation increase in reservoir inflow is associated with around 0.5 standard deviations decrease in output. However, the interpretation of ρ is not straightforward as the variation in price only comes from variation in demand. Since inflow constitutes a positive supply shock that will drive the price down independent of the variation in demand, it is not evident that ρ should be interpreted as a purely causal effect.

Table 5: The dependent variable is nuclear output.

	(1)	(2)	(3)	(OLS)
Slope (Θ)	-0.38*** (0.0026)	-0.17*** (0.0021)	-0.20*** (0.0019)	-0.17*** (0.00070)
Price (β)	1.18*** (0.0014)	0.55*** (0.0014)	0.35*** (0.0014)	0.21*** (0.00058)
Reservoir inflow (ρ)		-0.47*** (0.00050)	-0.46*** (0.00048)	-0.50*** (0.00041)
Year FE	Yes	Yes	Yes	Yes
Seasonal FE	No	No	Yes	Yes
Observations	26304	26304	26304	26304

Standardized beta coefficients; Standard errors in parentheses

Note: The dependent variable is hourly nuclear output. Year fixed effects are included in all regressions. Price and slope have been instrumented with forecasted consumption and its square.

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

As a last comment, it is of interest to note that the analysis above only considers the variation, rather than the absolute level of nuclear output. In a situation where hydro producers are not constrained by the amount of output that can be shifted between periods, the mean level of nuclear output is a better indicator of market power than

the variation in output. As a simplified example, consider a two-period case where one dominant nuclear producer faces a competitive fringe that only operates hydro production, and that hydro producers can shift production freely between periods by storing water in the reservoirs. If nuclear output is restricted in period one, hydro producers will counteract the change in relative prices across periods by allocating more production to period one, leading to an equalization of prices. If the fringe is sufficiently large, prices will be completely equalized across both periods. In this case the nuclear producer can only increase the mean price level in the system, while the timing of output reductions is of less importance. In the structural model presented below, I develop a framework for analyzing both the level and the variation in nuclear output, as well as estimating how joint ownership affects the incentives to exert market power.

5 A structural model of nuclear output

In this section I formulate a theoretical model which I use to simulate nuclear output given three behavioral assumptions: Joint profit maximization; Unilateral profit maximization; and a social planner. I start by formulating the model of unilateral profit maximization, which serves as a natural starting point as it is the only model that explicitly takes into account the level of joint ownership in the plants. Thus, Vattenfall takes the output decisions of Ringhals and Forsmark while E.ON is responsible for all output decisions in Oskarshamn. Fortum will remain a passive owner in all plants. In the simulation for Vattenfall, the Ringhals and Forsmark plants are aggregated to resemble one large plant. The majority owner chooses a level of output that maximizes the sum of its own profit from nuclear- and other output, taking the output of the remaining nuclear plants as given. Each majority owner takes into account both the passive ownership of other firms in the plant that it controls, and its own passive ownership in plants where it is only a minority owner (the more passive ownership the firm has, the stronger are the incentives to exert market power in its own plant).

I denote majority owner i 's profit by π^i , and the capacity constraint of firm i 's plant by \bar{q}^i . The inverse residual demand function facing firm i 's plant during hour t is $p_t(q_t^i)$, firm i 's supply function net of nuclear output is $S_t^i(p_t(q_t^i))$, the marginal cost of nuclear is f ,

and the total cost of other (i.e. non-nuclear) production is $C_t^i(p_t(q_t^i))$. Further, ownership shares in i 's own plant are denoted by η_i^i , and i 's passive ownership shares in the plants controlled by firm $j \neq i$ is η_j^i . The set of all 158 weeks-of-sample is denoted by \mathbf{W} , and the set of all years in the sample is \mathbf{Y} . The simplified optimization problem in which firm i 's only decision variable is nuclear output is then:

$$\max_{q_t^i} \pi^i = \sum_{t=1}^T \left\{ \underbrace{p_t(q_t^i)[\eta_i^i q_t^i + \sum_{j \neq i} \eta_j^i q_t^j + S_t^i(p_t(q_t^i))]}_{\text{Total revenue}} - \underbrace{f[\eta_i^i q_t^i + \sum_{j \neq i} \eta_j^i q_t^j] - C_t^i(p_t(q_t^i))}_{\text{Total cost}} \right\} \quad (3)$$

s.t.

$$q_t^i \leq \bar{q}^i$$

$$\sum_{t \in \mathbf{Y}} q_t^i \leq \sum_{t \in \mathbf{Y}} q_t^{i(obs)}$$

$$q_k^i = q_m^i \text{ if } k, m \in \mathbf{w}$$

$$p_t(q_t^i) \leq p_t^{obs} \times x$$

Where the objective function is the sum of i 's profits on both nuclear and non-nuclear production over all hours in the sample. Letting π^{coll} be the joint profit of the firms, and q^{nuc} be aggregated nuclear output, the objective function under collusion becomes:

$$\max_{q_t^{nuc}} \pi^{coll} = \sum_{t=1}^T \left\{ \underbrace{p_t(q_t^{nuc})[q_t^{nuc} + S_t^{coll}(q_t^{nuc})]}_{\text{Total revenue}} - \underbrace{f q_t^{nuc} - C_t^{coll}(q_t^{nuc})}_{\text{Total cost}} \right\} \quad (4)$$

And the corresponding objective function for the social planner is:

$$\max_{q_t^{nuc}} \pi^{planner} = \sum_{t=1}^T \left\{ \underbrace{\int_0^{q_t^{nuc}} p_t(x_t) dx_t}_{\text{Total revenue}} - \underbrace{f q_t^{nuc}}_{\text{Total cost}} \right\} \quad (5)$$

Moving to the constraints in (3), the first constraint represents the capacity constraint of the plant. The second constraint is the maintenance constraint. It states that simulated

yearly output must not exceed yearly observed output. Alternatively, this constraint could have been more precisely stated using data on total reported maintenance in the Urgent Messages Database. However, as shown in the results section, correcting observed output for events reported as forced outages (which is equivalent to failures) indicates that these events are not purely exogenous, but are also determined by strategic considerations. Also, as forced outages only accounts for about 10% of all output reductions, removing these events from the model only has a minor impact on the problem setup. The third constraint states that output has to be the same during each week-of-sample. This constraint reflects the fact that it is not possible to shut down a reactor for maintenance during short periods such as a couple of hours, or even days, at a time. Setting a weekly time window for the constraint also approximates the variation in data well: The absolute hourly median deviation from the observed mean weekly output is only about half a percentage for each plant, confirming that within-week variation is very small. As a robustness test I also estimated the model setting the constraint to 2,3 and 4 weeks respectively, with no qualitative differences in the results. The fourth constraint states that there is a limit to how much the firm can push up the price by restricting output. Specifically, the constraint introduces a horizontal segment on the inverse residual demand function facing i 's plant, for prices above $p_t^{obs} \times x$. There are two reasons for introducing this constraint. The first is due to regulatory threat. As discussed in section 3, nuclear owners are obliged not to perform maintenance during the winter season unless it can be motivated for safety reasons. This regulation was introduced after a series of extreme price hikes occurring during the winter 2009-2010, primarily as a result of low nuclear availability in combination with transmission constraints. Similar price effects could occur also during the sample period. For example, removing all output in the nuclear plants controlled by Vattenfall from the system supply function would more than double the price during 30 percent of all hours during the winter season. Since Vattenfall also enjoys a large market share on non-nuclear output, such a strategy will sometimes be beneficial. However, if that strategy is executed despite the regulatory obligation to refrain from doing so, the probability of the introduction of a severely stricter regulatory framework would increase. Empirical evidence that firms refrain from pushing up prices during periods of intensified regulatory oversight has also been documented in the context of the British electricity market (Wolfram, 1999; Wolak and Patrick, 2001). For a more general description of the

trade-off between a monopolist's short term profits and the possibility of future regulation, see [Glazer and McMillan \(1992\)](#). The second reason has to do with the behavior of competing firms. Even though it is likely that an unexpected drop in nuclear output could initially have a very large price effect, the effect would most likely be mitigated as other firms adapt their production planning to the new conditions, and start expanding output. In a hydro dominated market, an important aspect of this adaptation is the ability to shift output towards periods with high prices by storing water in the reservoirs. However, even though both the threat of future regulation and the dynamic effect on competing firms' behavior are convincing arguments for introducing an upper bound on the possibility to influence the price, there is no natural prior how to determine the value of x . I start by setting x to 1.3, implying that prices above approximately one standard deviation of the observed spot price are not feasible. Qualitatively, results are robust to varying x between 1 and 1.5.

Differentiating (3) with respect to q_t^i , denoting partial derivatives with subscripts, omitting time subscripts and rearranging yields:

$$p = \frac{\overbrace{\eta_i^i f + C_{q^i}^i}^{\text{Marginal cost}} - \overbrace{p_{q^i} [\eta_i^i q^i + \sum_{j \neq i} \eta_i^j q^j + S_{q^i}^i]}^{\text{Markup}}}{\eta_i^i + S_{q^i}^i} \quad (5)$$

Which gives the optimal bid-price as a function of marginal costs and the price sensitivity of the inverse residual demand function in each individual hour, also taking into account the profit on non-nuclear output. The corresponding equation for the social planner yields the familiar expression $p = f$, i.e. price equals marginal cost.

To see how the introduction of the maintenance constraint affects the allocation of output, I simplify the objective function and express weekly profits as a function of weekly output directly. Omitting the capacity constraint, the general maximization problem for year y becomes:

$$\max_{q_w} \pi_y = \sum_{w \in \mathbf{y}} \pi_w(q_w) \quad (6)$$

s.t.

$$\sum_{t \in \mathbf{y}} q_w \leq \sum_{w \in \mathbf{y}} q_w^{(obs)}$$

The Lagrangian is then:

$$L_y = \sum_{w \in \mathbf{y}} \pi_w(q_w) - \lambda \left(\sum_{w \in \mathbf{y}} q_w - \sum_{w \in \mathbf{y}} q_w^{(obs)} \right)$$

Given that optimal output is positive in each period, the first order conditions can be written as:

$$\frac{\partial \pi_k(q_k)}{\partial q_k} - \lambda = \frac{\partial \pi_l(q_l)}{\partial q_l} - \lambda \quad \forall k, l \in \mathbf{y} \quad (7)$$

Given that $\lambda > 0$, i.e. that the value of increasing total yearly output is positive, marginal revenues will be equalized across all weeks in the sample and equal to λ . Naturally, if the marginal revenue would be higher in week k than in week l , it would be optimal to allocate more output to week k and thereby increase total profits. For the social planner, the marginal value of increased production is the price, meaning that the social planner will seek to equalize prices across periods. For a description of the solution technique used to solve the full optimization problem, see Appendix B.

Fitting data to the model

Although some of the model components are observed, I need to make some further assumptions about the bidding behavior of the firms in order to estimate the model. First, I assume that all nuclear output is bid into the market as inelastic bids. This is a reasonable assumption, as nuclear plants cannot run the risk of not getting dispatched. It is also in line with the shape of the observed aggregated supply function, where around half of all accepted bids enter the supply function inelastically. Thus, I can construct the residual demand function of the nuclear plants in two steps: First I compute the

market supply function of other (i.e. non-nuclear) output $S_t^{other}(p_t)$ by subtracting the observed aggregate nuclear output from the market supply function, i.e. I get $S_t^{other}(p_t) = S_t^{market}(p_t) - q_t^{nuclear}$. The residual demand function facing the nuclear plant of firm i is then $q_t^i(p_t) = D_t^{market}(p_t) - S_t^{other}(p_t) - \sum_{j \neq i} q_t^j$, where $D_t^{market}(p_t)$ is the market demand function.

Since I do not have firm-specific bids, but firm-specific market shares, I assume that each firm's bid from non-nuclear output are scaled versions of $S_t^{other}(p_t)$. Let θ^i be the observed market share of firm i net of nuclear output ($\theta^{Vattenfall} = 0.17$, $\theta^{E.ON} = 0.03$, $\theta^{Fortum} = 0.10$). Then, the supply function of firm i net of nuclear output is $S_t^i(p_t) = \theta^i S_t^{other}(p_t)$. 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 $C_t^i(p_t) = \theta^i \int_{p_t^{min}}^{p_t} S_t^{other}(x) dx$. The assumption of competitive bidding of non-nuclear output is certainly a simplification, and will bias the incentives to exert market power downwards: If other production is bid in with a margin, firms will have less incentives to increase nuclear output as it could substitute away other, relatively cheap production. Therefore I also perform robustness tests where I vary the markup of other production up to 20%. However, even at a markup of 20%, the incentives to restrict nuclear output are only marginally distorted.

I approximate the marginal cost of nuclear f by the mean accounting fuel cost for all plants during the sample period, which is EUR 5/MWh, or equivalently 13% of the average day-ahead price. I compiled the accounted cost of fuel from the annual reports of each company. Due to the small variance in fuel costs, allowing the cost to vary across years and plants does not change the results. 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 on average EUR 1.5/MWh. The nuclear producers also pay a nuclear tax based on the nameplate capacity of each reactor. However, a reactor is only exempted from the tax if it remains inactive for more than 90 days. Therefore I do not consider the nuclear tax as a variable cost. I also conducted robustness tests by varying the marginal cost by 3 EUR/MWh in both directions, which only affected results marginally. For further information, see [OKG AB \(2013, 2014\)](#); [Forsmark \(2013, 2014\)](#); [Ringhals \(2013, 2014\)](#).

6 Results

6.1 Model selection

Figures 8, 9 and 10 depict the simulated output profiles of all plants given collusion, unilateral best-response and a social planner. More competitive behavior is associated with more output being allocated to the winter season, which is most clearly seen in Figure 10. During each winter, there are periods where plants are operating at (or close to) the capacity constraint of the system. Conversely, for the other models there is variation in output during the whole year, and in the collusive model the plants are rarely operating at the capacity constraint. Compared to the collusive model, the social planner would prefer to allocate 5 percent more of yearly output to the winter season, which is comparable to the diff-in-diff-estimate in the introductory section. To examine how well the simulated load profiles match data I start by regressing observed output on the simulated load profiles under each model, i.e. I regress

$$q_w^{obs} = \alpha + \beta_{sim}q_w^{sim} + \mathbf{M}\gamma + \epsilon_w$$

Where q_w^{obs} is the observed weekly output of all plants, q_w^{sim} is the simulated output under each model with its associated coefficient β_{sim} , and \mathbf{M} is a vector of month-of-sample fixed effects. A perfect fit would imply that $\hat{\beta}_{sim} = 1$ and $R^2 = 1$. Results are depicted in Table 6, where each column presents the result from a separate regression.

Table 6: Dependent variable is observed nuclear production.

	Collusion	Unilateral	Planner	Collusion	Unilateral	Planner
Simulated output	0.24*** (0.028)	0.19*** (0.028)	0.11*** (0.021)	0.10*** (0.022)	0.086*** (0.021)	0.022 (0.015)
Month-of-sample FE	No	No	No	Yes	Yes	Yes
Observations	158	158	158	158	158	158
Adjusted R^2	0.31	0.22	0.14	0.83	0.82	0.80

Standard errors in parentheses

Note: The dependent variable is nuclear production.

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

In the first three columns, no time fixed effects are included. Using adjusted R^2 as goodness of fit measure, we see that the collusive model fits data best with an adjusted R^2 of 0.31. The unilateral model performs somewhat worse with an R^2 of 0.22, and the social planner model has the least explanatory power with an R^2 of 0.14. All models yields positive and highly significant beta coefficients. When including month-of-sample fixed effects in the following three columns, absolute differences in adjusted R^2 becomes smaller, although the ordering in terms of R^2 remains intact. Also, the coefficient on the planner's load profile becomes insignificant, suggesting that within-month variations in output is mainly driven by strategic considerations. A relevant question is then whether the collusive model *alone* can explain the variation in output, or if firms display behavior that could partly be explained by the other models. There are several reason why this could be the case. In the literature, the most discussed one is due to the Folk theorem, essentially stating that any equilibria between unilateral profit maximization and joint profit maximization may be a Nash equilibrium in a setting with an infinitely repeated game. Another reason may be due to periodic deviations from a collusive agreement (see [Fabra and Toro \(2005\)](#) for an application to the Spanish electricity market), that may be triggered by e.g. variations in demand, which in turn affects deviation payoffs. In our setting, regulatory pressure; forward contracting; and vertical integration may also invoke a behavior that is more competitive than the collusive one.

To test whether the collusive model alone is the best predictor of firm behavior, following [Davidson and MacKinnon \(1981\)](#) I perform a J-test of non-nested hypotheses by considering the comprehensive model:

$$q_w^{obs} = (1 - \lambda^{alt})\beta_0 q_w^{coll} + \lambda^{alt}\beta_1 q_w^{alt} + \mathbf{M}\gamma + \epsilon_w$$

Where q_w^{alt} is the simulated output profile of the alternative hypothesis (i.e. unilateral profit maximization or a social planner), and the mixing parameter λ^{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 $\mathbf{M}\gamma$, and then testing the mixing parameter for statistical

Table 7: J-test of non-nested hypotheses

Alternative model	Month-of-sample FE	$H_0 : \lambda^{alt} = 0$	$H_0 : \lambda^{coll} = 0$
Unilateral	No	0.34	0.00
Planner	No	0.87	0.00
Unilateral	Yes	0.76	0.02
Planner	Yes	0.34	0.00

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

significance, i.e. $H_0 : \lambda^{alt} = 0$. If the null hypothesis is not rejected, it is also necessary to “reverse” the model and test $H_0 : \lambda^{coll} = 0$ to confirm that this new null hypothesis is indeed rejected (which is not guaranteed). Table 7 displays the p-values for different tests with and without including month-of-sample fixed effects. As seen in Table 7, $H_0 : \lambda^{alt} = 0$ cannot be rejected in any of the four tests. Further, $H_0 : \lambda^{coll} = 0$ is always rejected, consistent with the hypotheses that the collusive model is indeed the true model.

The strategic importance of outages reported as failures

To test whether outages reported as failures are likely to be exogenous events, I run the same regressions as above using the simulated output under collusion as the independent variable, but remove the reductions in output that are reported as failures (which account for about 15% of all reductions in output) from the dependent variable. If failures are purely exogenous events, the goodness of fit should now increase, as unexpected failures should just add random noise to the dependent variable.

Table 8: The dependent variables are nuclear production with and without failures.

	Inc fail	Net of fail
Simulated output	0.10*** (0.022)	0.074*** (0.020)
Month-of-sample FE	Yes	Yes
Observations	158	158
Adjusted R^2	0.83	0.81

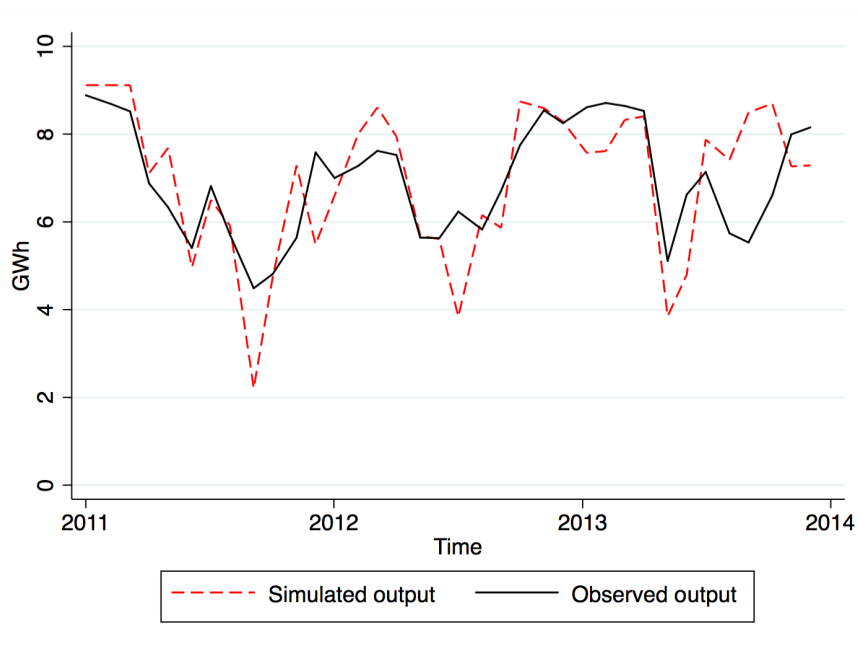
Standard errors in parentheses

Note: The dependent variables are nuclear production with and without failures.

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

However, as shown in Table 8, the adjusted R^2 instead decreases, suggesting that outages

Figure 8: Allocation of output under collusion



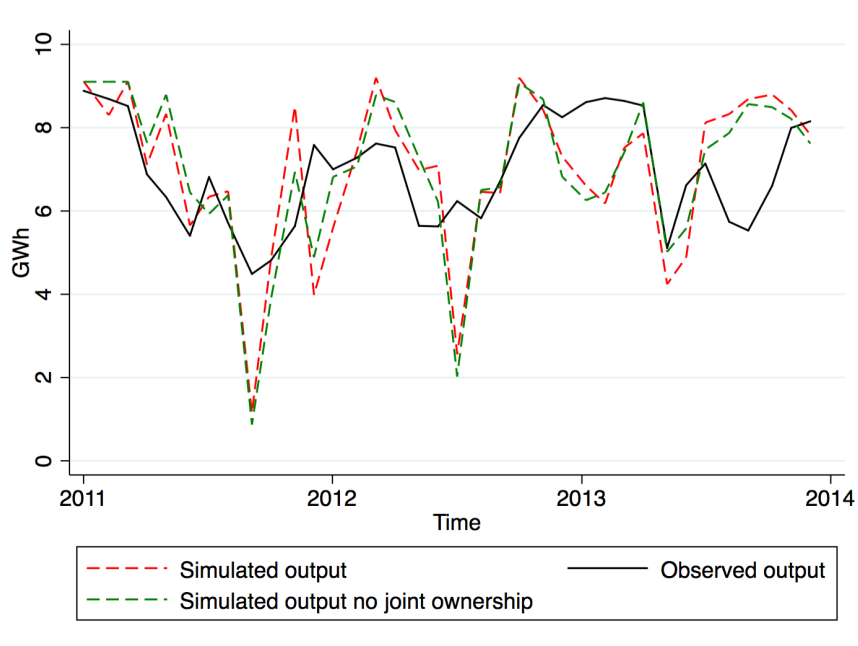
Note: This figure depicts the simulated mean monthly aggregate nuclear output under collusion, as well as observed output.

reported as failures are in fact also driven by strategic considerations, and should not be considered as fully exogenous events. Non-nested hypothesis testing analogous to the type described in the section above confirms this result, with $H_0 : \lambda^{\text{Net of fail}} = 0.87$, and $H_0 : \lambda^{\text{Inc fail}} = 0.04$ (when performing this test, simulated output is the dependent rather than the independent variable).

6.2 Welfare effects of more competitive behavior

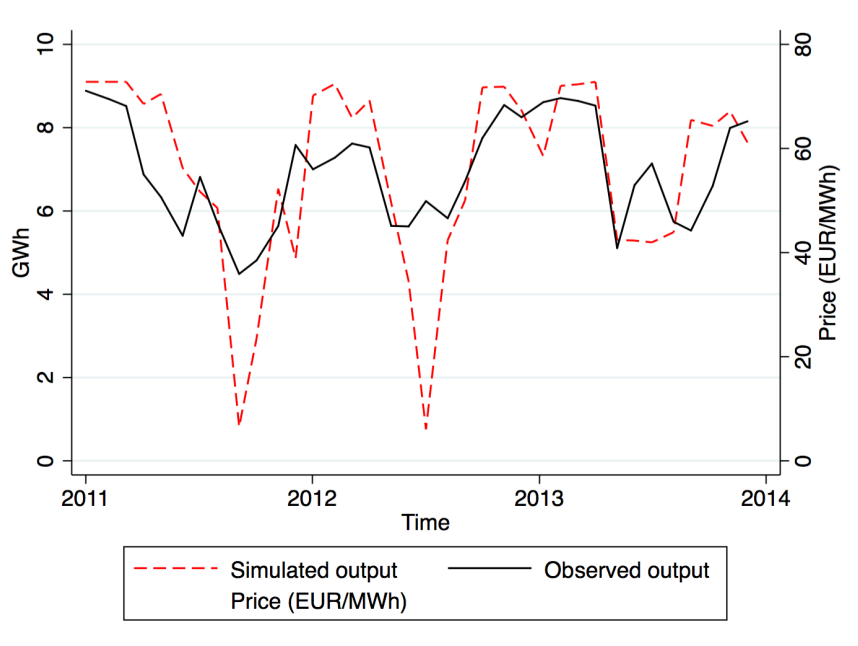
In this section I discuss the potential welfare gains of more competitive behavior, using the collusive output profile as a benchmark. In terms of short term deadweight losses, welfare gains are essentially zero due to an almost completely inelastic short term demand. Long term demand is likely to be more elastic, e.g. due to the sensitivity to production costs by the electricity intensive industry, and the possibility to switch from electric to other sources of heating. However, as it is beyond the scope of this paper to estimate the long term demand elasticity for electricity I do not provide any estimates of the size of this distortion. The potential short term welfare gains are instead due to lower production costs. As aggregate nuclear output is constant, gains in productive efficiencies arise due

Figure 9: Allocation of output under unilateral best-response



Note: This figure depicts the simulated mean monthly aggregate nuclear output under unilateral best-response, as well as observed output.

Figure 10: Allocation of output under social planner



Note: This figure depicts the simulated mean monthly aggregate nuclear output under a social planner, as well as observed output.

to a more efficient dispatch of other thermal production. Since more competitive behavior is associated with an equalization of prices across periods, this means that thermal plants are run more evenly, and peaking plants with high marginal costs are switched on less frequently. In combination with a convex system marginal cost function, average system production costs decrease (as a result of Jensen's inequality). Due to the unavailability of engineering cost estimates, I use the inverse system supply function as a proxy for the system marginal cost function, which is convex for almost all hours in the sample ⁷. As seen in the first column of Table 9, the unilateral equilibrium is associated with 2.4 percentage lower production costs. While this figure may appear rather small, one must keep in mind that the efficiency gain refers to the market as a whole, out of which the nuclear plants only account for about 20 percent. Terminating the joint ownership and letting each firm be the sole owner of one plant each decreases production cost by 6.1 percent, and under the social planner model production costs are 7.6 percentage lower compared to the collusive model.

Another short term welfare effect of more competitive behavior is the redistribution of welfare from producers to consumers due to a lower average price level. Unilateral profit maximization is associated with a 1.2 percent decrease in price, and terminating the joint ownership would lead to 5.1 percentages lower prices. Under the social planner model, prices are 6.6 percentages below the collusive price level. Further, as depicted in column 3, more competitive behavior is also associated with less price volatility. Although not a direct measure of welfare, a decrease in price volatility leads to an increase in welfare if market participants are risk-averse, although it is beyond the scope of this paper to quantify how large these gains could be.

Relaxing the maintenance constraint

So far, the analysis has rested on the assumption that the yearly level of output cannot increase, i.e. that all reported outages has in fact been necessary to perform at some point

⁷This approximation rests on the assumption that bids from hydro plants are inelastic. Although hydro production costs are essentially zero, there is an opportunity cost of producing today instead of storing water in the reservoir for future production (the so-called "water-value"). Therefore, some hydro output may be bid in at positive prices. Under the assumption that all water will be used for production at some point in time, shifting hydro output between periods does not alter hydro production costs.

Table 9: Welfare effects of moving from the collusive equilibrium

Model	$-\Delta$ prod.costs	$-\Delta$ price	$-\Delta$ Sd of price
Original maintenance constraint			
Unilateral	2.4	1.2	0.2
Unilateral no joint ownership	6.1	5.1	13.9
Social planner	7.6	6.6	26.3
Allowing for a capacity factor of 90%			
Unilateral	16.7	10.7	2.3
Unilateral no joint ownership	18.1	11.1	4.5
Social planner	20.8	12.3	15.6

Note: This table displays the potential welfare effects of moving to more competitive equilibria. Changes are expressed as percentages.

during the year. However, as the capacity factors of other European and U.S. plants of comparable vintages have remained around 90 percent during the last decade (as depicted in Figure 4), the possibility that firms have exerted market power by performing excessive maintenance should not be overlooked. In this section I therefore examine the welfare effects of allowing for a yearly capacity factor of up to 90 percent. The maintenance constraint associated with equation (3) now becomes:

$$\sum_{t \in \mathbf{y}} q_t^i \leq \sum_{t \in \mathbf{y}} \bar{q}_t^i \times 0.9$$

Results are depicted in the bottom three rows of Table 9. Except for the change in price volatility, all welfare effects are now amplified. The reason is that the new maintenance constraint is not binding in the collusive model. That is, even if firms were equipped with “state-of-the-art” plants that did not need any maintenance at all, firms would still have incentives to withdraw capacity in order to exert market power. In fact, the simulated average aggregate capacity factor only increases around two percent compared to the observed capacity factor. Conversely, in both the planner and the unilateral models, the new maintenance constraint is always binding. In effect, both the level and allocation of output is now different in comparison to the collusive model. Now, further production efficiencies arise when expensive thermal fossil-based production is substituted away in favor of nuclear, which causes production costs to drop by 16.7 % under the unilateral model, and 18.1 percentages after terminating the joint ownership. Under the social planner model, production costs drop by as much as 20.8%. The reason for the large

drop in production costs is that the share of thermal production is relatively small, and a substantial increase in nuclear output is able to substitute away a large fraction of these units. Also prices now drop substantially more, and corresponding figures are 10.7, 11.1 and 12.3 percent respectively. However, the drop in price volatility is relatively small. The reason is that when all plants are running near full capacity, there is less possibility to shift output between periods to equalize prices.

Another positive welfare effect of decreased thermal production is that CO_2 emissions are reduced (neglecting general equilibrium effects in the EU Emissions Trading System). Under the assumption that the whole increase in nuclear production would be compensated by a proportional decrease in fossil based production (which is a natural assumption as the total output of hydro, wind and combined heat- and power production depends on exogenous factors only), and that nuclear capacity factors increase from 80 to 90 percent, the drop in emissions would amount to 8 million metric tons of CO_2 annually, which is equivalent to 35% percent of the total Swedish CO_2 emission allowances in 2012 ⁸.

7 Conclusion

This paper studies the anti-competitive effects of joint ownership of Swedish nuclear plants, finding that joint ownership has generated incentives to exert market power by performing maintenance when the price effect of doing so is large. Although joint ownership itself amplifies the unilateral incentives to exert market, firm behavior is more consistent with a model of joint profit maximization. An interesting contrast to the results in this study is provided by [Davis and Wolfram \(2012\)](#), who find a positive effect of deregulation on the capacity utilization of U.S. nuclear plants (although their study is concerned with the level rather than the allocation of output). Further research could investigate how the anti-competitive effects discussed in the present paper may interact with the production efficiency gains from deregulation discussed in their paper.

To the best of my knowledge, no previous study has found evidence that firms exercise

⁸According to [U.S. Energy Information Administration \(2015\)](#), 1 kg of CO_2 produces roughly 1 kWh of electricity. Given an average hourly production increase of 1 GWh, we get that 8000 hours*1 ton = 8 million metric tons annually. Sweden's CO_2 allowance for 2012 was 22.5 million metric tons.

market power explicitly by withdrawing nuclear capacity. However, as the growth in electricity demand in virtually every developed country is flattening out while the supply of intermittent production in the form of wind and solar is increasing, electricity prices have seen a decline during recent years. Since the marginal cost of wind and solar is zero, exerting market power by withdrawing nuclear- or other baseload capacity may in the near future become a necessary means to keep electricity prices up during periods of positive supply shocks. By contrast, in the Nordic region intermittent production in the form of hydro power has always constituted a large share of electricity production. Since the present study finds that variation in intermittent hydro production is an important determinant of the incentives to exercise market power, similar phenomena may become prevalent also in other electricity markets where the share of intermittent production is increasing.

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 only estimating the markup on existing bids. Since maintenance schedules are available to other market participants through the Urgent Market Messages database, messages may be seen as information sharing in the form of *cheap talk*, indicating whether a firm intends 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 among firms. Since the EU is currently implementing regulations to increase the transparency in electricity markets in which maintenance scheduling is an essential ingredient ([ACER, 2015](#)), the findings in the present paper are highly relevant from a policy perspective. It is also of interest to note that in e.g. Spain, 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 suggests that such an arrangement could lead to a more efficient allocation of maintenance.

Another way to promote competition is to oblige firms to divest their nuclear capacity in so-called "virtual power plant auctions"; an arrangement in which the present owner

remains the operator of the plant but is obliged to sell its output in an auction separate to the wholesale market ([Ausubel and Cramton, 2010](#)). Then, withdrawing nuclear capacity will not directly affect the price of other plants in the firm's production portfolio. In this way, the market design allows economics of scale in plant operation to be realized, while at the same time promoting competition in the wholesale market. Since the nuclear plants make up such a large share of the owners' production portfolios, incentives to exercise market power through other generation units than nuclear would also be mitigated. Since their advent in 2001, virtual power plant auctions for various production types, including nuclear, have been used in France, Belgium, Spain, Denmark, Germany and Portugal.

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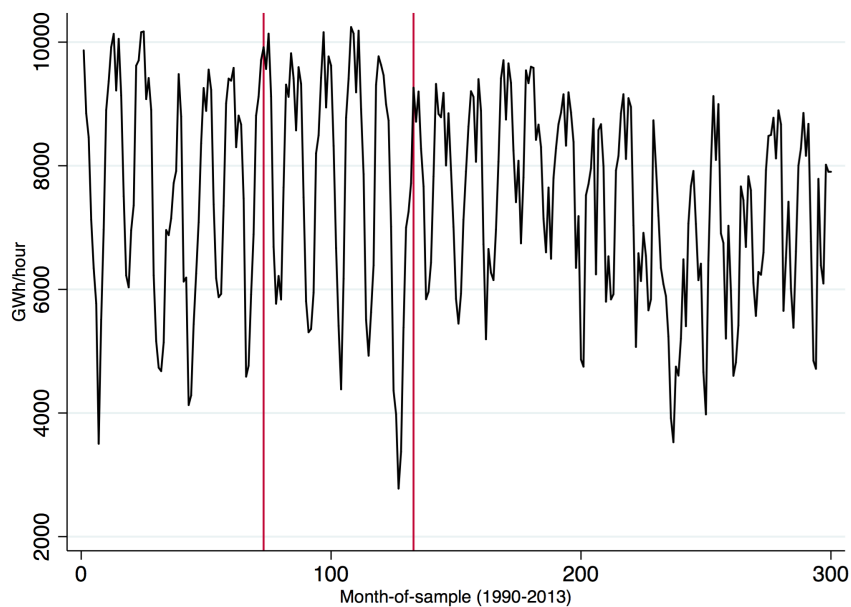
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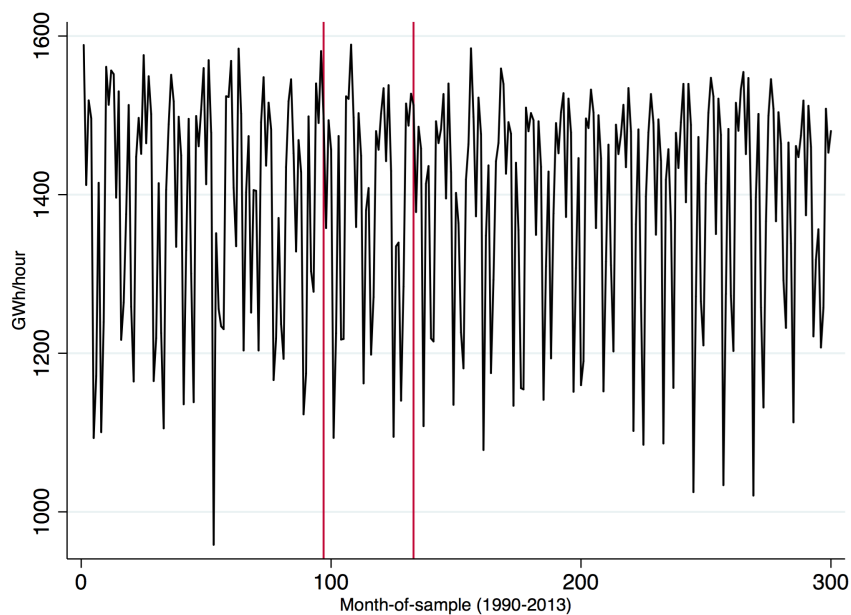
Appendix A

Figure A1: Swedish nuclear output 1990-2014



Note: This figure depicts monthly Swedish nuclear output during 1990-2014. Vertical lines are at the time of Swedish deregulation (1996) and at the time of the introduction of the joint ownership (2001).

Figure A2: Finnish nuclear output 1990-2014



Note: Note: This figure depicts monthly Finnish nuclear output during 1990-2014. Vertical lines are at the time of Finnish deregulation (1998) and at the time of the introduction of the joint ownership (2001).

Figure A3: 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>

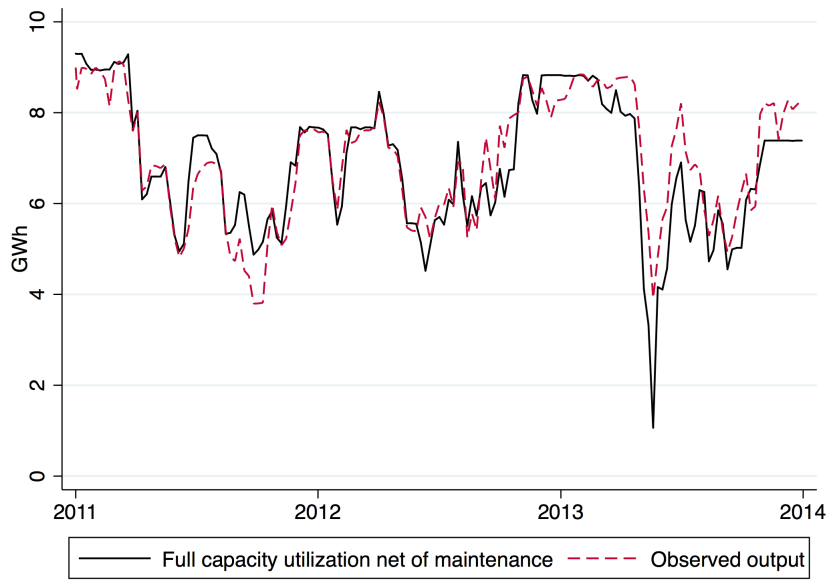
Note: This figure depicts an example of an Urgent Market Message regarding planned maintenance in reactor 2 in Forsmark.

Figure A4: Price zones in the Nordic electricity market



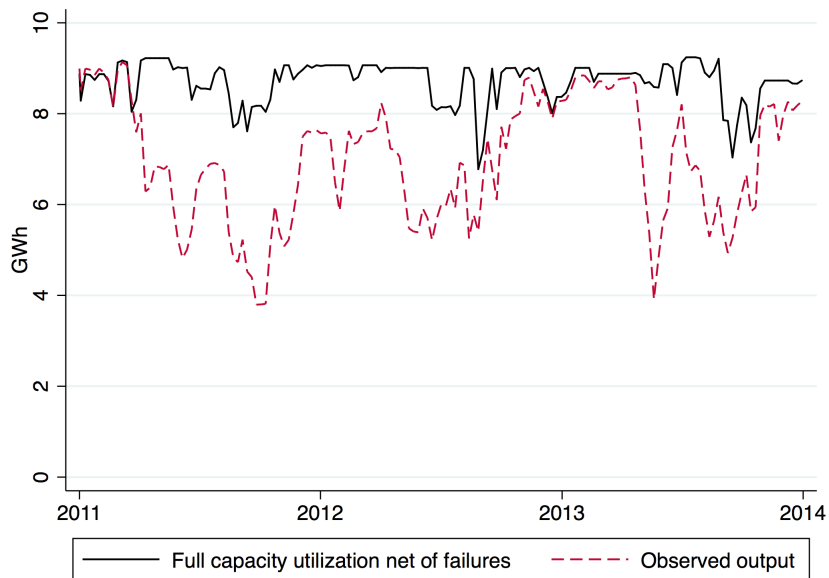
Note: This figure depicts price zones in the Nordic electricity market. All Swedish nuclear plants are located in zone "SE3".

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



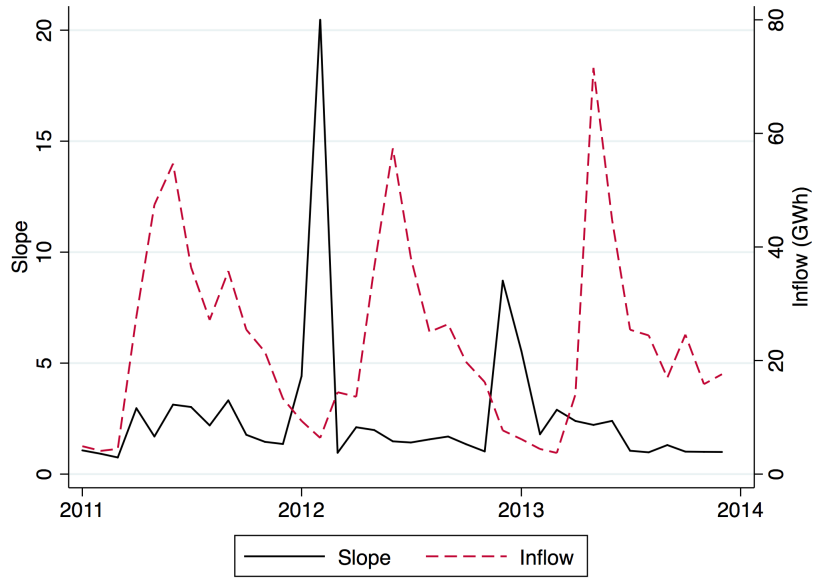
Note: This figure depicts the mean weekly aggregated nuclear output given that all plants would operate at full capacity except during outages reported as maintenance.

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



Note: This figure depicts the mean weekly aggregated nuclear output given that all plants would operate at full capacity except during outages reported as failures.

Figure A7: Reservoir inflow and mean slope of residual demand



Note: This figure depicts the mean monthly reservoir inflow in Sweden and Norway and the mean slope of the system residual demand function.

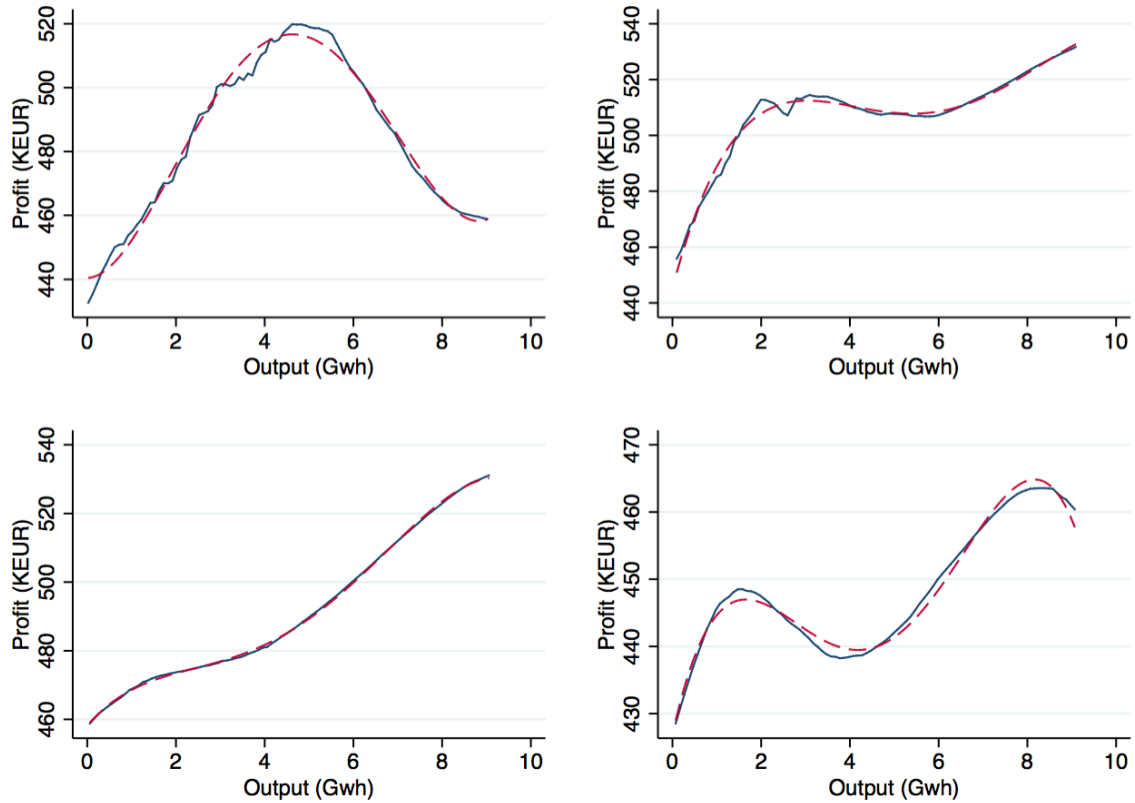
Appendix B

Solution technique

For each maximization problem, I start by discretizing the residual demand function in each hour by fitting it in blocks of 100 MWh. As the smallest plant (Oskarshamn) has a capacity of 2300 MW, 100 MW is only about 4 % of its capacity. I then apply the fourth constraint in equation (3), which imposes a horizontal segment on the left part of the inverse residual demand function in each hour of the sample. I then construct weekly profit functions by summing hourly profits over each feasible level of output for each week in the sample. This allows me to express the profit function for week w in terms of weekly output, i.e. $\pi_w^i(q_w^i)$.

In the next step I approximate the weekly profit functions using 4th order polynomials. Alternatively, a more flexible approach could have been used (such as a cubic spline), but this is not necessary. In fact, by visual inspection it rather appears that the fitted values captures the relevant variation in the data while neglecting trivial, irregular variation that is unlikely to influence firm decisions. A sample of the approximations are illustrated in Figure B1, where four different shapes of profit functions are depicted, together with the fitted values (all profit functions are from the collusive model). On the top left diagram, the profit function is concave within the entire feasible output range, with only one local maximum. The top right diagram has a local maximum at around 3 GWh of output, but attains its maximum at the capacity constraint. The bottom left function has a relatively even, positive slope within the whole relevant range. Naturally, this type of profit function gets more frequent the more competitive behavior is assumed. In the social planner framework, all profit functions are concave. Further, in the social planner framework all profit functions are increasing as long as the equilibrium price exceeds the marginal cost of nuclear at the capacity constraint, which is true in 95 percent of all weeks. The bottom right diagram displays a profit function with a local maximum at a very low level of output. However, if expanding output above 4 GWh profits start to increase again, to attain another local maximum at 8 GWh. This stems from the fact that there sometimes are two steep segments on the feasible portion of the residual demand

Figure B1: Continuous approximation of weekly profit functions



Note: this figure depicts weekly collusive discretized profit functions for four different sample weeks (blue), as well as the fitted values of 4th order polynomial approximations (dashed red).

function: One at very high prices, and one at very low prices (this can be seen by looking at the right diagram in Figure 5).

I proceed by solving the problem using Matlab's `fmincon` solver (MathWorks, 2015). However, the solver can only find a local optimum that satisfies the first order conditions, and is hence no guarantee to find a global optimum since not all profit functions are concave. I therefore combine the `fmincon` solver with the `GlobalSearch` algorithm of Matlab's Global Optimization Toolbox. `GlobalSearch` uses the scatter search algorithm (Glover et al., 2000) to find a large number of potential global solutions, and concludes by choosing the solution with the lowest value of the objective function. Depending on the optimization problem, `GlobalSearch` found between 40 and 98 local solutions. See Ugray et al. (2007) for a comprehensive description of the `GlobalSearch` algorithm.