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# Market Power in the German Wholesale Electricity Market

by

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Abstract:

This paper quantifies the degree of market power in the German wholesale electricity market. A fundamental model is used to derive competitive marginal cost estimators which are compared with observed electricity prices. Marginal costs are calculated focusing on market fundamentals such as plant capacities, fuel prices, and load structures. In addition, international power exchange and dynamic effects like start-up costs and hydro storage plant dispatch are incorporated. The comparison of marginal costs and prices reveals significant market power in the German electricity market, mainly exhibited during peak periods. Producer surplus is significantly increased by market power.

*Keywords:* Market Power, Electricity Markets, Energy Modelling

*JEL-classification:* C61; D43; L13; L94

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# I. INTRODUCTION

Most of Europe's electricity markets are in the process of liberalization. This process started in Great Britain and the Scandinavian countries. Efforts by the European Union lead to a major movement towards deregulation in continental Europe in the second half of the 1990s.[1] Germany arranged deregulation in 1998 when its new energy law became effective. As a consequence, the first German power exchange in Leipzig started operations in June 2000. Among other contracts, the exchange trades contracts for electricity for every hour of the following day. Prices for these spot contracts have changed considerably since June 2000. In particular, monthly base load spot prices (delivery of 1 megawatt (MW) for every hour of the month) varied between 15 and 25 Euros/megawatt hour (MWh) during the year 2000 and most of 2001. In December 2001, the monthly base reached 50 Euros/MWh, with single hours peaking at nearly 1000 Euros/MWh. While prices returned to lower levels after December 2001, we show that the spread between marginal costs and prices widened considerably.

Analogous to the discussions around the California crisis (see Borenstein et al. (2000)), two competing hypotheses concerning the cause of these price movements are discussed: the first hypothesis is that high prices in the German electricity market are caused by "fundamental factors" such as fuel prices, generation of hydro plants, and wind power generation. The opposing hypothesis states that they are the result of market power. This debate has vital implications for the evaluation of the success of the whole liberalization process in electricity markets. The disadvantages of regulation have to be compared with the disadvantages of market power. Market power, understood as the ability to profitably raise prices above marginal costs, leads to inefficiencies mainly due to restricted output and suboptimal plant dispatch. This paper contributes to the discussion by deriving a competitive price estimator with a complex fundamental model. A comparison of these competitive price estimators with observed prices comes to the conclusion that the amount of market power in the German electricity market is significant.

Traditional concentration measures such as the Hirschman-Herfindahl index are rather raw tools for an evaluation of competition and market power in electricity markets.[2] Since information on costs of production and other additional market data are available, they should be incorporated in a reliable valuation model. These data can be used in an analysis of market outcomes and marginal costs. Borenstein et al. (2002) distinguish two approaches for the analysis of market outcomes. The first analyzes single companies and their bidding behavior. Among others, Wolfram (1998) has conducted such an analysis for the electricity market in England and Wales, and Puller (2001) for California. The second approach is at market level. An analysis at market level compares observed prices with estimated marginal costs for the

1 A milestone towards deregulated electricity markets in the European Union was the EU Directive 96/92/EC which determined common rules for the internal electricity market in the European Union. .

2 See Borenstein and Bushnell (1999) for a discussion of traditional concentration measures and oligopoly models for the analysis of market power in electricity markets.

aggregated industry supply function. This approach, chosen by Borenstein et al. (2002) and Wolfram (1999), among others, is also followed in this paper. While this market level perspective is less informative on companies' bidding strategies, the results are far more robust for two reasons. Firstly, a disaggregated approach necessitates the analysis of firms' bidding strategies. Data on firms' bids are difficult to obtain, estimating them adds further uncertainties to the analysis. Secondly, the aggregated approach leaves computational resources for a very detailed analysis of marginal costs.

For example, the quantification of marginal costs involves dynamic aspects which are very difficult to include in a disaggregated model of strategic behavior. However, the detailed analysis of marginal costs is especially important in the German market. For one, the German power market is highly integrated into the European grid: The interconnector capacity connecting Germany with its neighboring countries sums up to more than 13 gigawatt (GW), exceeding 15% of highest load. Hence, it is very important to incorporate international power exchange in the analysis. In addition, Germany (partly through exchanges with Austria and Switzerland) is significantly influenced by hydro power generation. Optimizing hydro storage generation adds a dynamic component to the problem.[3] Hydro storage plants bid opportunity costs rather than variable costs. Since these plants have a fixed energy budget determined by water inflows, the opportunity costs depend on expected future prices. Start-up costs are another dynamic issue. They comprise costs for preheating and network synchronization of power plants before production. Start-up costs are price relevant for plants that, for example, shut down during low demand levels at night or at weekends. These costs, however, are most important during peak periods as will be shown later. Since market power is usually also most pronounced during peak periods, it is important to distinguish clearly between the two. Power exchange between regions as well as generation of hydro storage plants and start-up decisions are endogenous to the model presented in this paper.

We derive system marginal cost estimators using a linear optimization model. The model minimizes total generation costs by simultaneously optimizing plant dispatch in Germany and other European countries. Hence, international power exchange is optimized endogenously. Since 72 price realizations per month are distinguished, the dynamic effects of hydro storage plant dispatch and start-up decisions can also be modeled endogenously. System marginal costs are the cost in the system inflicted by a marginal increase in load in a region, taking also into account effects in other regions and other periods. Hence, our approach focuses on the costs of the next megawatt potentially produced and not on the cost of the last megawatt produced. This approach avoids the problem that peak load prices even in a competitive system may be significantly above variable generation costs of the most expensive unit currently producing.[4]

3 Production costs $C_t$ at t do not only depend on output at t but also on past and future production levels: $C_t=C(q_1,\ldots,q_t,\ldots,q_T)$, where t=1,…,T is a time index.

4 An intuitive description of this problem can be found in Brennan (2003).

In a perfectly competitive market, these marginal costs can be used as price estimators. Hence, marginal costs calculated using the model serve as an estimator of competitive electricity prices in the German spot market. Comparing the marginal cost estimator with observed market prices at the German power exchange allows a quantification of market power in the market. One main result is that the spread between cost estimators and prices increases over time. One reason for increasing market power is increasing concentration in the market. The eight large companies in Germany[5] merged to only four over the period of observation. Selten (1973) argues that "four are a few and six are many", indicating that the potential for market power significantly increases when the number of firms is reduced from eight to four.

However, it is difficult to pin down a date for a structural break from this increase in concentration. Firstly, at the time a merger is cleared it is not immediately implemented in the organizational structure of a company. It takes an uncertain time span before two merged companies really act as one. Secondly, increasing potential for market power due to increased concentration is not necessarily exploited. Companies have to learn how to exercise market power. The task of reducing output to maximize producer surplus is fairly complex. Both effects are difficult to quantify. However, some additional facts hint at a change around December 2001. The Enron bankruptcy distorted electricity markets worldwide. While Enron did not control much capacity in Germany, contracts had to be renegotiated. German wholesale prices reached an all-time high in December 2001.

The expected change in market power is confirmed by our data. An econometric analysis identifies a structural break. While a structural break in December 2001 is statistically significant, the most likely break date is two month before December 2001, namely between August and September 2001. While the ratio of average monthly wholesale prices to average monthly system marginal cost estimators is 0.98 during the period from June 2000 to August 2001, this ratio increases to 1.49 during September 2001 and June 2003. Average prices in the second period from September 2001 to June 2003 are significantly higher than in the first period between June 2000 and August 2001, but cost estimators are even lower in the second period. Lower fuel prices are probably the most important factor for this decline in cost estimators, but the development of other factors, for example demand as well as the generation of hydro plants and wind generation, is also incorporated in the marginal cost estimators. Since these market fundamentals cannot explain the rise in prices, increasing market power is considered as the main factor responsible for increased differences between costs and prices.

Statements about the average degree of market power in a month can be amended by a more detailed analysis, since our model distinguishes 864 different load realizations per year. However, instead of extensively analyzing single hours, we distinguish periods of high and low demand in every month. The results show that market power is strongest during periods of high demand. Wolfram (1998) finds evidence for the England and Wales market that more

5 Before market liberalization, these eight large companies ("Verbundunternehmen") were vertically integrated and also operated the high voltage transmission grid.

inframarginal capacity induces higher bids since more capacity profits from higher prices. In addition, less unused capacity during high demand periods can lower the price elasticity of supply thus raising the potential for strategic bidding. Prices in the period after the break, dating from September 2001 to June 2003, are 77% above cost estimators. Much less evidence for market power is detected during low demand periods. In addition, model results allow a quantification of producer surplus. The model determines marginal costs by determining the cost minimal plant dispatch in every time period. Marginal costs (equaling competitive price estimators), generation by different stations in every period and generation costs can be used to calculate the producer surplus. The analysis shows that producer surplus rises significantly due to the exercise of market power.

The detailed focus on marginal costs is preferable for two additional reasons. Firstly, the German power exchange does not publish any data on bidding behavior. That makes it difficult to investigate players' bidding strategies. Wolfram (1998) tests whether suppliers with high inframarginal capacity submit higher bids than smaller competitors for similar plants. While this is very interesting, such an analysis is not possible for the German market due to the unavailability of the necessary data. Secondly, bids in the England and Wales pool market, which was the focus of that study, had to be valid for the whole day. This idea of one supply curve which is optimal for several demand realizations is related to the concept of supply function equilibria (SFE) described by Klemperer and Meyer (1989). Pioneering work using SFE in electricity markets has been carried out by Green and Newberry (1992), Bolle (1992), and Green (1996). While firms bid supply curves in the German exchange, these supply curves can be changed from hour to hour. Thus, since the remaining uncertainty regarding demand is relatively low, the SFE approach appears to be less meaningful for an analysis of Germany's electricity spot market.

The paper is structured as follows. Section II characterizes the German electricity market at the generation level. Both its market structure and the European Energy Exchange as the reference market are described. Section III derives price estimators based on system marginal costs. In section IV, the results from this derivation are explored with regard to spreads, different demand periods and producer surplus. Section V concludes the paper.

## II. THE GERMAN ELECTRICITY MARKET

Electricity markets exhibit unique features which distinguish electricity from nearly all other goods. Electricity is a homogenous product at a certain time on the demand side.[6] Storing electric energy is expensive. Electricity flows are grid-bound. Electricity demand is volatile with pronounced seasonality on a daily, weekly and annual level. Different plant technologies have varying short-run generation costs. These facts lead to large variations in marginal generation costs. Additionally, due to the fact that capacity has to cover the highest demand levels, there is unused capacity most of the time.

6 One exception is the development of a market for "green electricity". Here, consumers voluntarily buy certificates for electricity produced by renewable energy sources. However, this market is very small.

The German electricity market is the largest in Europe. Total net consumption summed up to 532 TWh in 2000. Total installed net generating capacity at the beginning of the year 2000 amounted to 116 GW (25% hard coal, 22% gas, 18% nuclear power, 18% lignite, 8% hydro power, 5% wind, 4% oil and others). When the German electricity market was liberalized, there were eight major integrated generation companies. During the years 2000 and 2001, mergers and acquisitions reduced this number to four. RWE and VEW merged but kept the name RWE. Preussen Elektra and Bayernwerk merged to E.ON. Swedish Vattenfall first bought HEW. Afterwards, HEW, VEAG, and BEWAG merged to Vattenfall Europe. In addition, French EdF bought a major stake of the south-western player EnBW. While all remaining big players are vertically integrated, they are legally unbundled. The capacity share of the largest four companies increased from 42% of total German generation capacity before these mergers to 61%.

The first German power exchange, the Leipzig Power Exchange (LPX), started operations on 15 June 2000. While before electricity was traded over-the-counter (OTC), the LPX was the first market place which quoted hourly prices. The trading system was Nord Pool's SAPRI. The Scandinavian power exchange was also a major shareholder (35%). On 8 August 2000, a second power exchange started, the European Energy Exchange (EEX) in Frankfurt. EEX used Eurex's XETRA trading system. Both exchanges merged in July 2002 and formed the new European Energy Exchange based in Leipzig.[7] The new exchange uses the SAPRI exchange system for the auction market of single hours.[8] Bids and offers have to be sent to the exchange until 12 p.m. of the day before delivery. Market results are published by EEX until 12:30 p.m. and become binding half an hour later. All trading ceases at 2:30 p.m. when binding schedules have to be reported to the grid operators. While trades in principle are possible between the EEX's auction ending and market closure at 2:30, traders report that volumes on the OTC market are low in that period.

The only source for intra-day energy trades are reserve and balancing markets. Reserve and balancing energy is not traded at the exchange. Instead, the four major German grid operators buy these services in an auction. While primary and secondary reserve is contracted for six month, there is a daily auction of tertiary reserve. This auction is held independent of the regular electricity market and regionally separated for the four different reserve and balancing zones. However, both producers and consumers are obliged to contract their true expected generation and consumption on regular electricity markets. If necessary, the grid operators, who are responsible for the provision of reserve and balancing services, can punish conspicuous deviations in court. Hence, reserve markets are for unforeseen variations in demand and supply; financially motivated intra-day trade is blocked. For this reason, the EEX's day-ahead auction market of single hours is the closest to a spot market.

7 Further information on the EEX can be found on their webpage: www.eex.de.

8 In addition to the auctioning of hourly electricity, the exchange trades spot electricity in a continuous block trading using XETRA. The volume in these block trades is rather small (1,5 TWh in 2003). These block trades are not used in this analysis.

That is the reason why the EEX market clearing price was chosen as the reference price for this analysis. For the period where both German exchanges operated, volume weighted averages of LPX and EEX are used as market price benchmark. While market shares of the exchange spot markets were low in the beginning (2.7 TWh from June to December 2000), they increased steadily over time (15.6 TWh in 2001, 26.6 TWh in 2002). In 2003, the exchange's hourly spot auction had a share of nearly 10 percent (48 TWh) of total German net consumption. Additional electricity is traded on the OTC spot market but the largest share of the market is bound by long-term contracts.

## III. MODELLING MARGINAL COSTS

In this section, the derivation of marginal costs is described. The general structure of the model used to calculate system marginal costs (SMC) is presented.[9] In addition, economically important set screws for the prognosis of marginal costs such as hydro storage production, international exchange, start-up costs, and combined heat and power production are discussed in greater detail.

### Model Structure

In a perfectly competitive environment, the hourly spot price is given by the marginal costs.[10] Mas-Collel et al. (1995) define market power as "the ability to alter profitably prices away from competitive levels." Since it is impossible to observe marginal costs in electricity markets, the difference between marginal cost estimates and prices cannot exclusively be attributed to market power. The approach in this paper overestimates the capabilities of market participants resulting in a downward bias of system marginal costs: The model assumes perfect foresight concerning fuel prices, load, electricity generation from wind, and other sources, and excludes any market frictions. The market is assumed to be free of arbitrage opportunities. In addition, information about fundamental factors is incomplete. It is therefore not possible to replicate exactly the situation seen by the power plant operators. This may lead to an overestimate or underestimate of marginal costs. However, these differences should not vary significantly over time. Hence, the long period of investigation with 37 independent observations allows statements about the development of market power over time.

Regardless of a possible over- or underestimate, the quality of input data is absolutely crucial. The liberalization had two opposed effects on the amount of data published. Increased competition and the increased value of information have made generators much more reluctant to provide data to the public. However, regulators and grid companies are working in the opposite direction, increasing the data published in some countries. While most data are available at a monthly resolution, there is very little data available on at hourly basis. It should be mentioned that additional data simplify research, but in a strategic context they can make collu-

9 The first version of this model was developed by Kreuzberg (2001). An overview of the algebraic structure of the model can be found in the appendix of that publication.

10 See Schweppe (1988) for a discussion of marginal costs and spot prices for electricity.

sion more stable. The reason is that a player's deviations from collusive strategies are more easily detected by competitors.

The model calculates short-run system marginal cost estimators. These comprise fuel costs, start-up costs, and opportunity costs for hydro storage plants.[11] In the short term, investment costs as well as costs for labor, and repair and maintenance are sunk. Hence, these costs should not influence plant dispatch; marginal cost estimators should not incorporate them. Short-run system marginal cost estimators are derived by solving a linear programming problem.[12] The objective function is global cost minimization over all model regions. The model becomes particularly appealing through the numerous realistic constraints. Among the more important are:

- Generation has to equal an exogenously given demand at every time everywhere in the network.
- Generation is limited by installed available capacities.
- Power exchange between regions cannot exceed interconnector capacities.
- Dynamic effects to be considered are:
  1. The total generation of hydro storage plants is limited by a monthly energy budget.
  2. Plants may only produce in a given period if they are started up in the same period or have been started in a period of lower demand.

Before these issues are discussed in more detail, some remarks should be made on the model's time resolution. As was pointed out in the last section, power plant dispatch decisions are dynamic. Hence, the optimal approach would simultaneously optimize every single hourly dispatch for the whole optimization period. However, given the complexity of the problem, this is beyond computational feasibility. The model used in this paper optimizes dispatch in 12 independent months per year. During every month, a representative week is analyzed. A representative week consists of one typical working day which is assumed to appear 4.8 times, 1 Saturday and 1.2 Sundays (including public holidays). In total, 72 different price realizations are simultaneously calculated in every month.

**Model Demand**

Hourly demand for the representative week is calculated as follows: Firstly, total annual energy consumption for a region is obtained from available statistics. Secondly, monthly shares are used to break demand down to a monthly level. Thirdly, available data on the hourly structure of load are used to get hourly load curves for the representative working day, Saturday and Sunday. Hence, demand is exogenous and it is price inelastic in the model. While this is an approximation (avoiding non-linearities), short-run price elasticity of demand is very small in electricity markets.

11 Fuel costs for nuclear plants comprise the variable components of front end as well as back end costs.

Total hourly demand derived that way cannot be used directly in the optimization process. It has to be corrected for the generation of non-dispatchable electricity sources. Non-dispatchable generation capacity does not react on scarcity signals. Hence, their dispatch cannot be optimized by a cost-minimizing model. Wind power is a typical example. Due to their extremely low variable costs, wind plants produce as much electricity as wind conditions allow. Wind power generation in Germany increased from 9.5 terawatt hours (TWh) in 2000 to an estimated 17.5 TWh in 2003. Hydro run of river plants are another source of non-dispatchable energy. Depending on hydrological conditions, about 17 TWh of electricity are generated by run of river plants. Wind and run of river generation are subtracted from demand exogenously. Plant dispatch is optimized over the residual demand. More complicated are combined heat and power plants. These plants produce both heat and electricity in a combined production process. While the dispatch decision for these plants is influenced by electricity prices, other restrictions such as heat demand constitute limiting factors. For the calculation of marginal costs, these plants are divided into two groups. The dispatch of plants with a high power-to-heat ratio is assumed to be driven by electricity prices and is endogenously optimized. Plants with a low power-to-heat ratio are treated as exogenous non-dispatchable generation. Their capacity is not included in the optimization process and their production reduces model load. Additional examples of non-dispatchable production are renewable energy sources besides wind and hydro, waste combustion, and electricity produced for railways. In total, 115 TWh of non-dispatchable generation are deducted from German demand in the year 2000. The hourly structure of non-dispatchable generation is derived using a procedure similar to the one described for total demand. Production for the remaining 417 TWh is endogenously optimized in the model.

**Generation Technologies and Model Regions**

Ten different generation technologies are distinguished. The more important are nuclear plants, lignite plants, hard-coal-fired capacity, highly efficient gas-fired CCGT plants, older gas-fired capacity, gas and oil turbines, and three hydro technologies (run-of-river, storage, and pump storage plants). The development of capacity endowments over the observation period is exogenous input into the analysis. In every technology, plants are aggregated in vintage classes comprising five years.[13] Parameters can be varied by region, generation technology and vintage. Hydro storage plants without pumps receive a monthly energy budget. Pump storage plants' pumping and production of electricity is optimized given restrictions on available capacity.

Plant dispatch in seven European core regions is simultaneously optimized. Power exchange between regions is a result of this optimization. Alternatively, power exchange could be based

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12 This linear programming problem is highly complex and involves a total of 400000 equations (with 370000 endogenous variables) to be solved.

13 For example, all hard coal plants in Germany built between 1960 and 1964 are aggregated in the vintage class of 1965.

on historic flows. Endogenous optimization is advantageous for two reasons. Firstly, observed flows react to prices instead of costs and hence are likely to be influenced by market power. This would distort calculation of marginal costs. Secondly, data on hourly power exchange are hardly published.

Reserve and balancing requirement are another issue influencing the supply curve. In Germany, a total of 6-8 GW reserve and balancing capacity is necessary. This capacity is not available for production on regular markets. Wind power will further increase these numbers. Primary, secondary and tertiary reserve is distinguished. The main difference is the time until the reserve capacity has to be available. This response time limits the types of plants able to provide the service, especially for primary and secondary reserve. Primary and secondary reserve can be provided by storage and pump storage plants, and by varying operating plants' load factors. Tertiary reserve can also be provided by "cold reserve", namely gas turbines. These gas turbines are not utilized during most hours of the year, so the effect of tertiary reserve provision on generation costs on the regular market is relatively small.

On the other hand, primary and secondary reserves significantly influence electricity supply on the regular market since capacity with relevant opportunity costs on the regular market is used. However, this influence and the optimal reserve portfolio vary over time. This effect is included in the model by modeling dispatch for regular markets as well as primary and secondary reserve provision simultaneously. However, the focus is on the sufficient supply of reserve *capacity*, stochastic *generation* of these reserve capacities is not modeled. To sum up, the model finds the cost minimizing plant dispatch in the electricity market consisting of the regular market as well as reserve markets.

Plant dispatch is not only optimized for Germany but also for six other European core regions. The six core regions besides Germany[14] are France, Belgium, the Netherlands, Austria/Switzerland combined as the Alpine region, Great Britain, and Italy. The size of a region is determined by the grid capacity. If interconnector capacity is abundant over nearly all periods of the year, areas or even countries can be combined to one model region. Power exchange between modeled regions is only restricted by the capacity of the interconnectors. The model optimizes exchange following a contract paths approach. Power exchange with other countries, i.e. Northern and Central Eastern Europe, is determined exogenously.

**The Impact of International Power Exchange and Start-up Costs**

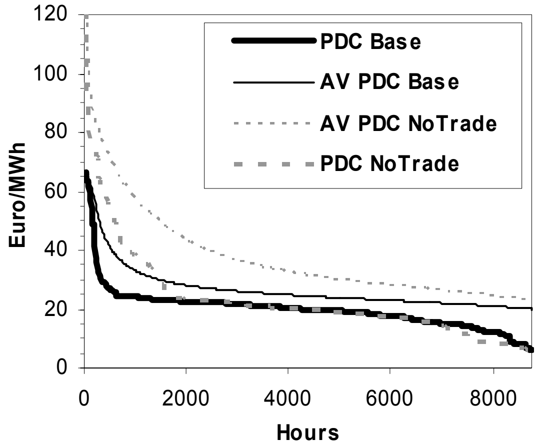
The left part of Figure 1 quantifies the impact of international power exchange on German electricity prices. The figure contains price duration curves (PDC) and average price duration curves (AV PDC). PDCs are price curves sorted in descending order. The two bold PDCs show German marginal cost estimators for the year 2001. The "PDC base" line is the result of a model run for the year 2001 with endogenous power exchange. These results are also used

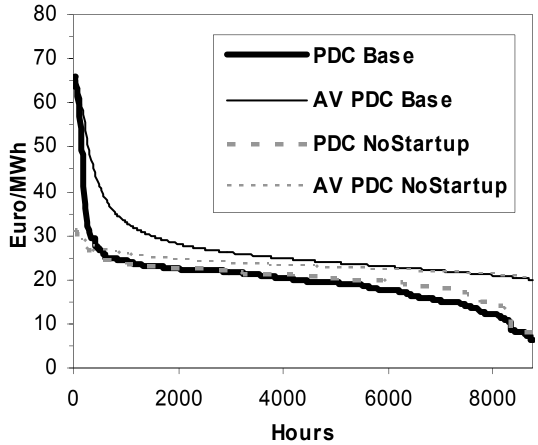
[14] Luxembourg is added to the Germany since there are rarely any binding network restrictions between these regions and the largest German generator RWE operates Luxembourg's largest plant.

in the remainder of this paper as marginal cost estimators for the year 2001. The “PDC no trade” line is based on exactly the same data set but German power exchange is restricted to zero. It becomes clear that international power exchange has a large impact on the market especially during high price periods. This is mostly caused by imports from the Alpine countries. Both Austria and Switzerland have a large endowment of hydro storage capacity. These are used to shave peaks in demand, avoiding the use of less efficient – and hence more expensive – capacity. In addition, the resulting production profile for thermal capacity is less volatile. This saves start-up costs. On the other hand, Germany exports during low price periods. Hence, SMC without trade are even below SMC with trade during the very low cost hours. The average price duration curves give the average of all prices up to that hour. For the very right, this is the annual base (average of all 8760 hours of the year). Annual average increases from 20.0 Euros/MWh to 22.9 Euros/MWh without the possibility of international power exchange.

The right part of Figure 1 is very similar but compares the base case with a scenario without start-up costs. It is noticeable that start-up costs increase marginal costs significantly during high price periods. Lucas and Taylor (1994) discuss start-up costs and their influence on marginal costs. The intuition is that a load increase during most periods can be served by an earlier start-up (or later shut-down) of a plant that has to be started up anyway. The exception is the period with highest load for thermal plants. In this period, a load increase has to be served by otherwise unused capacity. Hence, start-up costs are cost relevant: During the lowest demand periods, the opposite can be observed. SMC estimators with start-up costs are below SMC without start-up costs. While this result is contra intuitive at first glance, it can be explained. During the lowest demand period, a load increase increases variable operating costs but saves a start-up in the next period since more capacity can be operated without interruption. It is important to note that these two effects net out over the year in terms of variable costs. Nonetheless, it is advantageous to include start-up costs in a model. Otherwise, high prices during peak periods might be wrongly attributed to market power. This is especially important if only parts of the observation period are analyzed, for example high price periods as is done in section IV. In addition, demand during peak periods is higher, so volume-weighted prices increase if start-up costs are included.

**Figure 1: Influence of International Exchange and Start-up Costs on Price Duration Curves**



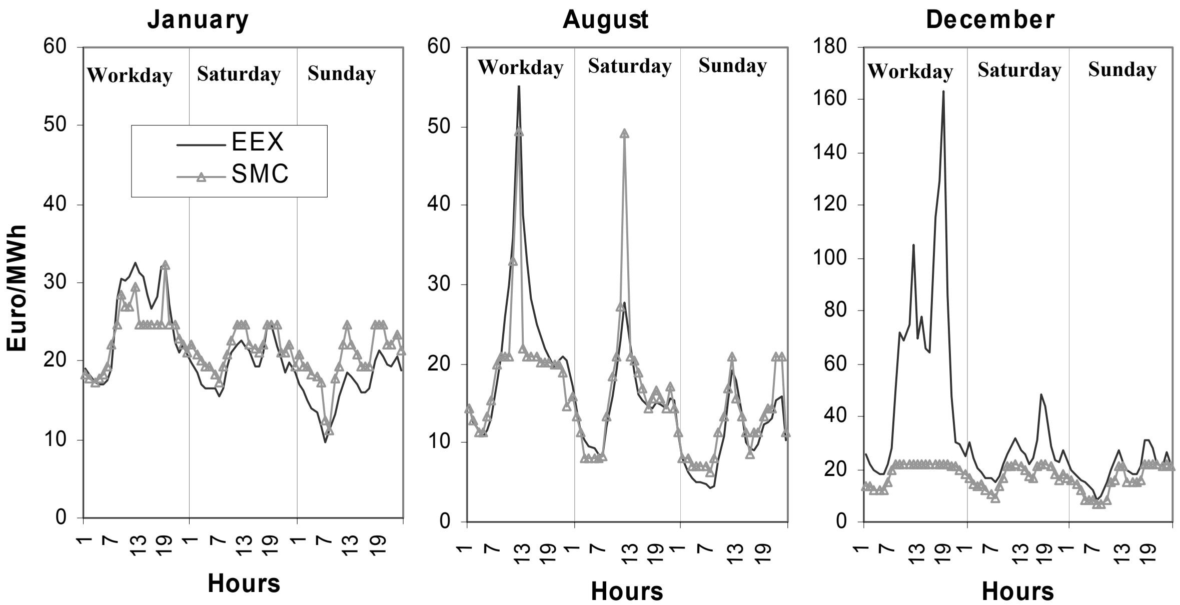

## IV. EMPIRICAL RESULTS

In the first part of this section, aggregated monthly average prices and costs are compared. A structural break will be identified. Afterwards, high demand and low demand periods will be distinguished. This is done to test the hypothesis that market power is strongest during high demand periods.

### Presentation of Marginal Costs and Prices

Figure 2 gives examples of hourly price curves for Germany. Each diagram contains 24 hours for a typical working day, Saturday and Sunday. The EEX prices are obtained by averaging all working day realizations at a certain hour in the month. Usually, these are about 20 different realizations per hour and month. The same is done for Saturdays and Sundays (again including public holidays). Here, there are fewer realizations per month (4 to 5 for an hour on Saturdays, up to 8 for every hour of Sundays and public holidays). The exchange realizations are compared with the model's SMC estimates. It can be seen that the model reflects the structure of the EEX prices fairly well during January and August 2001. Prices and SMC estimators differ greatly during December 2001. Prices are two or three times as high as cost estimates especially during high price periods.

**Figure 2: Hourly Average Prices and SMC Estimators, Germany 2001**




A detailed analysis of these hourly price curves for all months would be extremely burdensome. For that reason, hourly realizations are aggregated into a monthly base, peak and off-peak realization. A monthly base realization is calculated by averaging all hourly price realizations at the exchange. Model estimates are time-weighted averages of the 72 realizations per month. The peak period comprises Monday to Friday from 8 a.m. to 8 p.m. (including public holidays). This follows the definition of the EEX peak contracts. All other hours are contained in off-peak realizations.

**Figure 3: Monthly Averages – EEX and Cost Estimators**

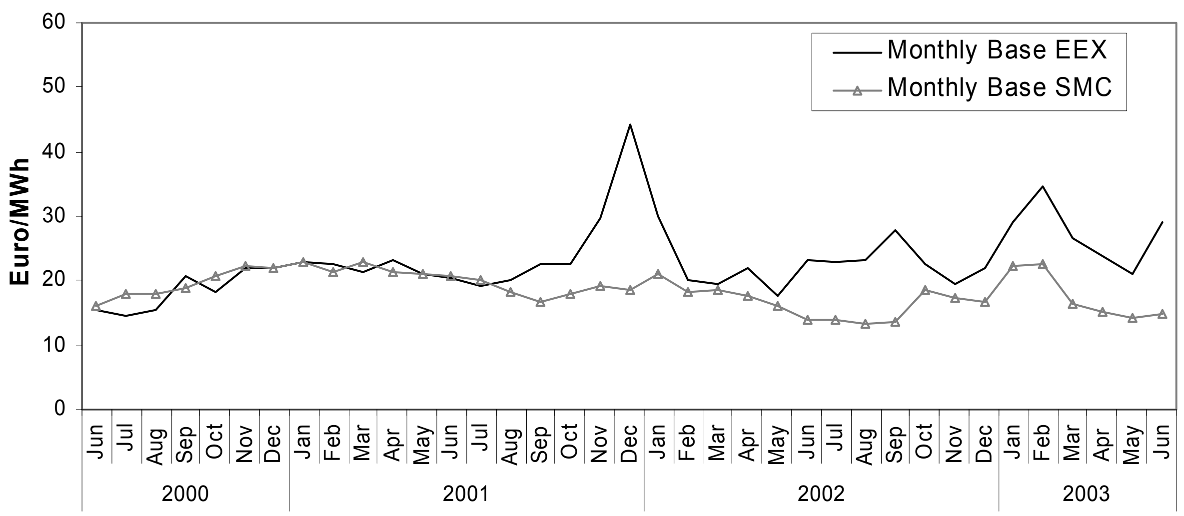



Figure 3 visualizes a key observation in the market. The development of the difference between model estimates and market price over time is striking. A simple graphical analysis shows that the coherence between costs and prices is much stronger at the beginning of the observation period. This corresponds to the increasing concentration in the market. Our hypothesis is that the difference between prices and marginal costs is small in the beginning of the observation period when the market is less concentrated but increases to the end when only four major companies are left.

**Test for Structural Break**

This hypothesis can be analyzed using time series analysis. We start by testing whether a structural break can be found in the data. In the case of such a break, the most likely break date has to be identified. In addition, the question whether the spread between costs and prices in the two time intervals is constant has to be analyzed. It has been pointed out that very high prices and the Enron bankruptcy suggest a break around December 2001. This is supported by looking at Figure 3. EEX prices exceed 40 Euros/MWh in December. Looking at the cost curve, it is obvious that this extreme price spike is not justified by marginal costs. Hence, the difference between marginal cost estimator and price amounts to more than 25 Euros/MWh. This is the maximum difference of all observation periods. In addition, Enron reported major losses in autumn 2001 and filed for bankruptcy on 2 December 2001. The impact of Enron on the European electricity market is assumed to be mainly psychological since Enron owned little capacity and it is questionable whether these plants' dispatch was influenced by Enron's bankruptcy in the first place. However, many contracts had to be renegotiated and some not yet established mainly American players left the European market in the reverberations of the Enron bankruptcy.

These arguments are indications for a structural break in December 2001. We perform econometric tests to test for the most likely break date. This is done using a Quandt likelihood ratio (QLR) test. Andrews (1993) provides a table with critical values for the QLR test. The test splits the observation period in two and compares regression coefficients in both subsets:

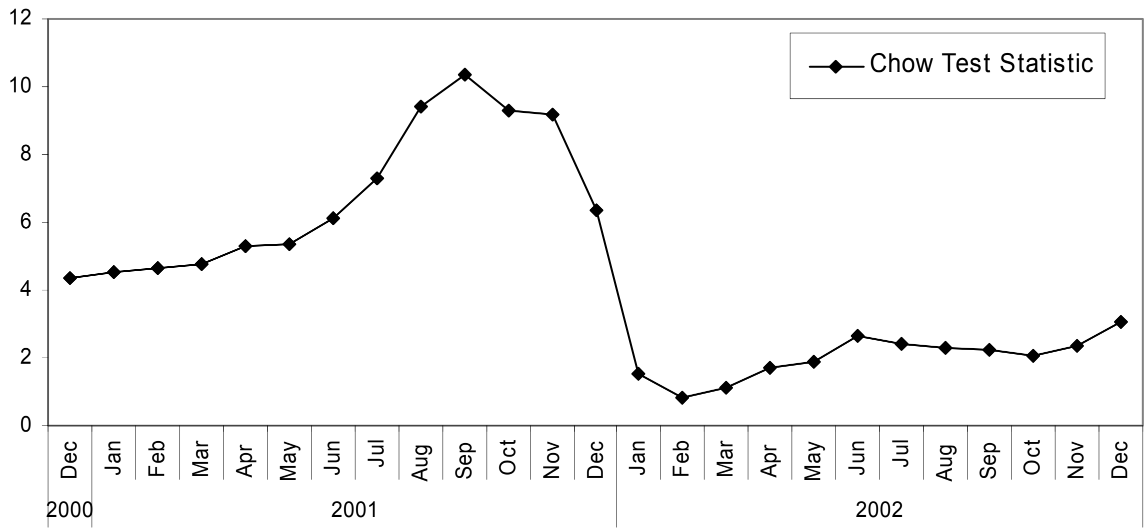
$p_t = \hat{\alpha}^{(1)} + \hat{\beta}^{(1)} * SMC_t + \hat{u}_t,\ t = 1,...,\tau - 1$ and

$p_t = \hat{\alpha}^{(2)} + \hat{\beta}^{(2)} * SMC_t + \hat{u}_t,\ t = \tau,...,T$ .

$p_t$ denominates the EEX price in month $t$, $SMC_t$ the cost estimator, $\hat{\alpha}$ is the estimated intercept in each period, and $\hat{\beta}$ is the estimated coefficient. The error terms $\hat{u}_1,\ldots,\hat{u}_T$ are assumed to be uncorrelated and normally distributed. As long as the market is competitive, prices should equal marginal costs. In the regression, this means that the intercept $\alpha$ should be zero and the coefficient $\beta$ should be equal to one. In addition, $R^2$ should be high. However, once increased concentration in the market influences players' bidding strategies, the correlation between marginal costs and prices should be worse.

The hypothesis tested is whether $\hat{\beta}^{(1)} = \hat{\beta}^{(2)}$ and simultaneously $\hat{\alpha}^{(1)} = \hat{\alpha}^{(2)}$. The QLR test computes such F-statistics for a range of potential break dates. The largest resulting F-statistic is the most likely break date. Because the maximum of a range of F-statistics is taken, the distribution is different from an individual F-statistic. Furthermore, a QLR test should not be computed over the whole range of observations, because the distribution depends on the endpoints of the subsample analyzed. In this paper, a trimming of 15% at both ends is used. Hence, the period from December 2000 to December 2002 is tested for a break. Figure 4 contains Chow test statistics for this period. The QLR test critical value for the given data is 7.8 (significant on a 99% level). The Chow statistic reaches a maximum of 10.4 between August and September 2001. This is a consistent estimator for a break point. The data set will be split between August and September 2001 in the following analysis. The first period contains the data from June 2000 to August 2001, the second period contains the months from September 2001 to June 2003.

**Figure 4: Chow Test Statistic for a Structural Break**




Once the break date is identified, the coefficients can be analyzed. An OLS regression for the first period estimates $\hat{\alpha}^{(1)} = -2.71$ with a standard deviation of $\hat{\sigma}\left(\hat{\alpha}^{(1)}\right) = 4.33$ and $\hat{\beta}^{(1)} = 1.12$ with a standard deviation of $\hat{\sigma}\left(\hat{\beta}^{(1)}\right) = 0.21$. Hence, the original hypothesis that $\hat{\alpha}^{(1)} = 0$ and $\hat{\beta}^{(1)} = 1$ cannot be rejected for the first period. However, it can be verified that there is a positive correlation between prices and SMC ($\hat{\beta}^{(1)} > 0$). $R^2$ is high and amounts to 0.68. To sum up, there is strong evidence that prices are very similar to our marginal cost estimators in the first period from June 2000 to August 2001.

The result for the analogous regression in the second period is different. As is already clear from Figure 3, the correlation between SMC and price is much weaker in this period. The regression estimates are $\hat{\alpha}^{(2)} = 10.1$ with a standard deviation of $\hat{\sigma}\left(\hat{\alpha}^{(2)}\right) = 7.98$ and $\hat{\beta}^{(2)} = 0.88$ with a standard deviation of $\hat{\sigma}\left(\hat{\beta}^{(2)}\right) = 0.46$. While both $\hat{\alpha}^{(2)} = 0$ and $\hat{\beta}^{(2)} = 1$ still cannot be rejected at a statistically significant level, standard errors are much higher and $R^2$ is only 0.15.

In the first period from June 2000 to August 2001 there is no evidence for market power. The ratio of monthly EEX prices to average monthly marginal cost is 0.98. Hence, prices are even slightly below estimated marginal costs. Short-run marginal costs should be a lower bound for prices. As was pointed out before, both suboptimal bids by market participants and uncertainties in model input data do possibly lead to SMC estimates above prices. For the period after the structural break, the ratio of prices to costs increases to 1.49. While marginal costs fell from the first to the second period, prices increased significantly. This caused the strong increase in differences between prices and costs.

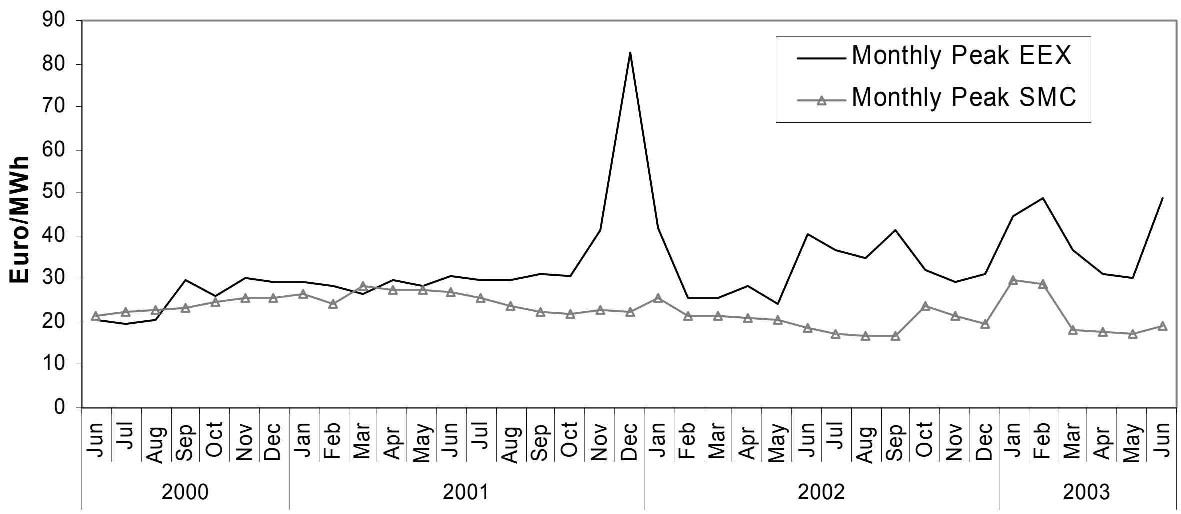
The question whether differences increase over time by a linear factor is not confirmed by statistical analyses. A constant spread between prices and costs during each of the two time series cannot be rejected. Therefore, a trend in either period cannot be supported.[15]

**Comparison of High and Low Demand Periods**

It is often argued that market power is higher during high demand periods than during low demand periods. Both a higher amount of inframarginal capacity profiting from higher prices and the amount of free capacity are intuitive reasons for this. The available data (aggregated market approach) do not allow an analysis of different players' bidding strategies at different load levels. However, as can be seen in Figure 5 and Figure 6, strategic mark-ups are indeed much higher during high demand periods.

Figure 5 compares the monthly averages of SMC and EEX prices during peak periods. Since the date of the structural break has already been identified by the QLR test for monthly averages, a simple Chow test is used to test whether a break really has occurred during August and September 2001. This is supported by looking at Figure 5 and is statistically significant. The ratio from prices to costs increases from 1.09 in first period to 1.77 in the second period. In other words, the average monthly mark-up on costs is 77% for the second period.

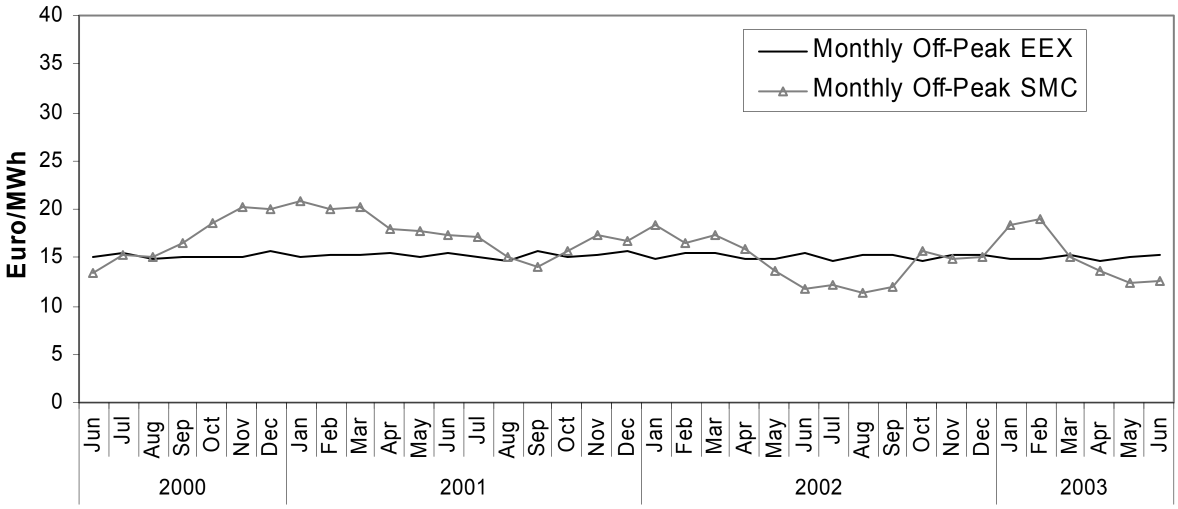
**Figure 5: Monthly Averages Peak Hours– EEX and Cost Estimators**




15 However, this is different if the extreme period around December 2001 is left out of the analysis. For the period from February 2002 to June 2003, a Regression of price differences on time yields a coefficient of 0.47 per month (significant on the 95% level).

The same type of analysis for the off-peak periods shows a very different result. The structural break between August and September 2001 is still significant. However, Figure 6 shows that the deviation between marginal costs and prices is much smaller. The ratio of prices to cost estimators is 0.85 in the first period and raises to 1.01 in the second period.

**Figure 6: Monthly Averages Off-Peak hours – EEX and Cost Estimators**



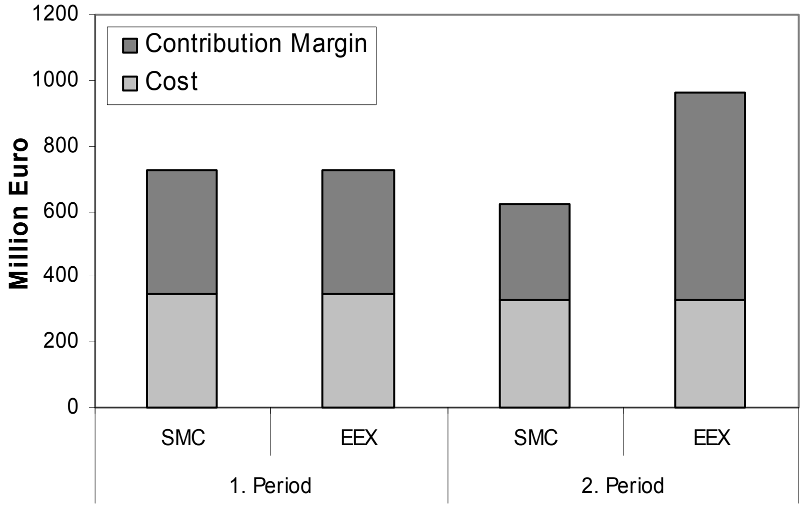

## Producer Surplus

How do higher prices translate into higher profits for the electricity supply industry? Three figures are necessary to derive producer surplus. The first is plants' hourly generation. The other two are plants' production costs and hourly prices. All three are determined by the model. The model optimizes plant dispatch by minimizing production costs. These data can be used to determine producer surplus for the capacity in the model by multiplying generation with marginal costs (price estimator) and subtracting variable generation costs.[16] Producer surplus earned under marginal costs can be compared with contribution margin earned by selling in the EEX spot market. This is done by assuming the same plant dispatch and production costs but using EEX spot prices instead of SMC estimators as prices. Most likely, plant dispatch under strategic behavior is not cost minimal, and production costs would increase compared to the competitive scenario. Hence, the results presented in this section can be seen as an upper limit for producer surplus under strategic behavior.

Since the two periods determined by the QLR test do not have the same length, a comparison of absolute figures is misleading. For that reason, monthly average costs and revenues are calculated in both periods. Figure 7 contains monthly average revenues and costs for both periods.

16 Non-dispatchable generation is not considered in the following calculation of revenues since its dispatch is not optimized by the model. This is because data on the generation cost of combined production of heat and power plants is difficult to obtain.

**Figure 7: Monthly Average Revenue, Costs, and Producer Surplus**




Revenues for the first period (June 2000 to August 2001) are very similar for SMC and exchange prices. Monthly average revenues for all modeled capacity in Germany amount to about 727 million Euros in both cases. Monthly average generation costs are defined to be the same in both cases. They amount to 345 million Euros. Since producer surplus is the difference of revenues and variable costs, they are also the same and amount to a monthly figure of 382 million Euros.

Average monthly revenues for the second period are 624 million Euros for SMC and 962 million Euros for EEX prices. Producer surplus increases from 296 million Euros under SMC to 633 million Euros using EEX prices. This is an average monthly difference in producer surplus of 337 million Euros. It is interesting to note that the extra profit gained in December 2001 was 1.4 billion Euros. While observed prices are 49% above SMC estimators for the second period, producer surplus calculated using EEX prices are even 114% above producer surplus under SMC. The reason is that marginal costs cover both production costs and producer surplus while the increase in prices due to market power exclusively raises producer surplus. In addition, it should be noted that competitive estimates of revenues, costs, and producer surplus is all lower in the second period than in the first. Hence, there seems to be no fundamental reason for the observed price increase in the second period.

However, if investment in new capacity is necessary, prices have to cover total costs of new capacity. Otherwise, no investments would take place. In a perfectly competitive market, missing capital costs are recovered during the hours without free capacity. Prices are above marginal costs of the most expensive generating unit during these hours since the price elasticity of demand determines the price. Given the low short-run elasticity of demand, this leads to extreme price spikes (if load can be covered at all). Strategic behavior by incumbents is another mean to raise short-run prices on a sustainable level (covering total costs). If prices are raised strategically, the resulting price curve is less volatile than in the competitive case since producer surplus is not exclusively earned during the highest demand hours. This lowers price spikes during peak periods. In addition, less pronounced price spikes lessen the threat of regulators implementing price caps which try to limit excessive profits but might prevent entrance. If investors assume that price caps will be set too tightly to allow total cost coverage, they will not invest. Hence, both excessive price spikes and the regulatory threat of price caps can be softened if strategic behavior raises prices. This whole argument assumes that market entrance is a credible threat for excessive capacity reductions. If prices above long run marginal costs of new capacity trigger new market entry by non-strategic players, strategic prices should not significantly exceed long run marginal costs. Analyzing EEX price data for the year 2003, we find that prices are still slightly below long run marginal costs of a new CCGT plant.[17] If prices were significantly above long run marginal costs, new capacity would drive down both marginal generation costs as well as the incumbents' market share. A lower market share lessens the potential for market power. It should not be forgotten that the exercise of market power, even if raising prices to a level allowing cost coverage, leads to inefficiencies. Plant dispatch resulting from strategic bidding is not cost minimal. Capacity of the strategic players is replaced by other players' capacity with higher marginal costs. Furthermore, the total amount of electricity produced is lower than in a competitive equilibrium. To the extent demand is elastic, this may lead to an additional dead-weight loss in welfare.

## V. CONCLUSION

The paper quantifies the extent of market power in the German electricity market by comparing a marginal-cost-based competitive price estimator with observed power prices on the German electricity spot market. The difference between marginal costs and prices is attributed to market power. Stochastic analyses identify a structural break between August and September 2001 dividing the observation period in two sub-periods. There is no evidence for market power in the first period form June 2000 to August 2001. Monthly average prices are even slightly below marginal cost estimates. However, there is strong evidence of market power in the second period from September 2001 to June 2003: on average, prices are nearly 50% above estimated costs. Mostly, these price differences lie in periods of high demand. In the second period, prices are 77% higher than cost estimators for these high demand phases. Producer surplus based on EEX prices are also calculated: in the second period, they are more than double compared to the competitive benchmark.

Increased concentration was named as one potential reason for the evidenced increase in producer surplus and market power. Another potential reason is learning which unfortunately is not easily measured and thus also difficult to quantify. However, electricity spot market auctions repeated on a daily basis will no doubt have led to more sophisticated bidding strategies.

Regardless of these origins of market power, the careful analysis of fundamentals is absolutely crucial for an understanding of electricity markets and possibly resulting market power. Even in perfectly competitive markets, fundamentals lead to strong variations in prices over

17 Long run marginal costs include labor costs, repair and maintenance costs, and annualized investment costs in addition to short run cost.

time and justify price spikes during extremely tight situations of supply and demand. In addition, due to differences on both the supply and the demand side, competitive prices have to be different for different regions. Hence, high prices alone are no proof of market power and the associated inefficiencies and rent shiftings. Most empirical studies determine marginal cost estimators by simply “moving” hourly load (demand) over a static supply curve. However, the supply functions of different periods are interdependent and they are not constant over time. Non-dispatchable energy sources such as wind power and combined heat and power plants vary from hour to hour and influence the correct supply function significantly. International power exchange, start-up costs, hydro storage plants’ opportunity costs and provision of reserve power are important and were thus modeled endogenously in this paper.

By quantifying the degree of market power in the market, the paper sheds light on the discussion of recent price rises in the German electricity industry. Strategic bidding by generating companies seems to be the primary source for price increases in the German market. Changes in market fundamentals play a minor role. Average fundamental cost estimators during the second period were below the average of the first period while spot prices in the market were much higher. This result is important for the discussion of the success of market liberalization and deregulation in Germany. Market power is one of the key problems in deregulated markets. Potential changes in regulation and market design have to be considered if the degree of market power is too large. However, the quantification of “too large” is difficult. The disadvantages of deregulated markets have to be compared with the disadvantages of a tighter regulation. Several potential measures to mitigate market power are discussed in the literature. They show greatly varying degrees of regulatory interference. Among others, the literature discusses measures to increase the price elasticity of demand and to expand forward contract volumes, the implementation of price caps, the promotion of additional interconnector capacity, and the divestiture of generating companies.

Further research could apply the model to other regions and conduct similar analyses. The results can be used to evaluate different market designs. Other possible directions cover the measurement of efficiency losses of market power. However, this necessitates a model simulating strategic players’ bidding behavior. It is a challenge not yet truly accomplished to implement at least the most important fundamentals of electricity markets in an empirical model of strategic behavior.

## VI. APPENDIX

All marginal cost estimates in electricity markets are sensitive to variations in data. Parameterization becomes even more important if the model used to derive marginal cost estimators is as complex as ours. However, the most important results in this paper, namely the strong increase in market power over time, are most likely robust. This is especially true since we made an effort to use a consistent data set in this analysis. The same data sources were used over the whole period of observation.[18] Nonetheless, a more detailed description of both the data and the model can make the analysis less abstract and support the understanding of the derivation of marginal cost estimators.

**Data Sources**

The presentation of all data used in the analysis would be too extensive. For that reason, monthly data for the year 2001 are described as an example. The year 2001 seems representative since it covers periods both before and after the structural break. However, additional data can be made available on request.

Plant efficiencies and installed capacities for the different vintage classes are taken from the Institute of Energy Economics' plant database. This database comprises installed electrical and heat generating capacity, type of fuel, efficiencies and the year of construction for units in all model regions. In Germany, 1700 units are registered. However, not all these installed capacity is available for production and balancing services. Plants may be offline due to stochastic outages as well as scheduled maintenance. Historic realized availabilities are reported for nuclear plants.[19] However, approximated availabilities have to be used for conventional thermal capacity. These are mainly derived from older statistics published before the liberalization process increased the value of data in the market.

Fuel prices (Figure 8) are gathered from different sources. Hard coal prices for Northwestern Europe (fob Amsterdam, Rotterdam, Antwerp) can be obtained from McCloskey's Coal Report. For each model region, an average markup for transshipping and transportation to plant site is added. Cross border gas prices are taken from Heren Energy's European Gas Markets. These commercial sources generally have low time lags in data publication. Fuel oil prices are provided by the Federal Statistical Office Germany.

18 The exception is some data for 2003: for example nuclear availabilities and hydro generation figures had to be taken from UCTE since some national statistics were not yet available at the time.

19 Historic availabilities for German nuclear plants can be found on http://www.vgb.org.

**Figure 8: Monthly Fuel Prices at Plant, Germany 2001 [Euro/MWh ncv]**

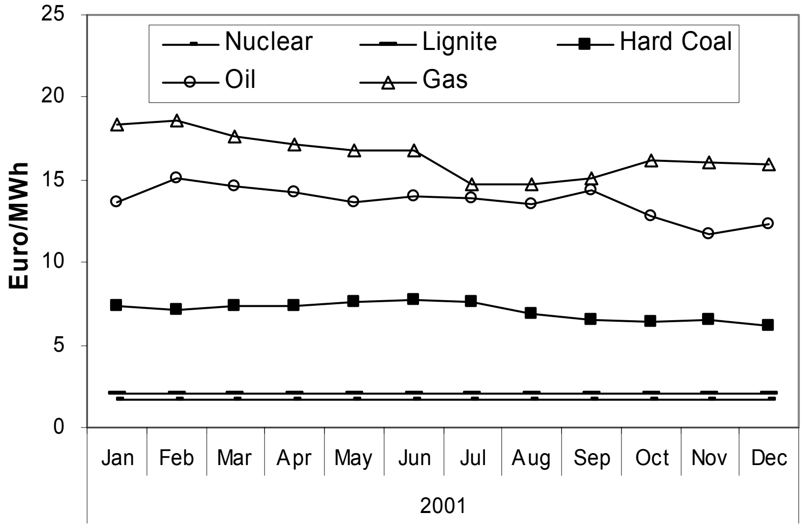
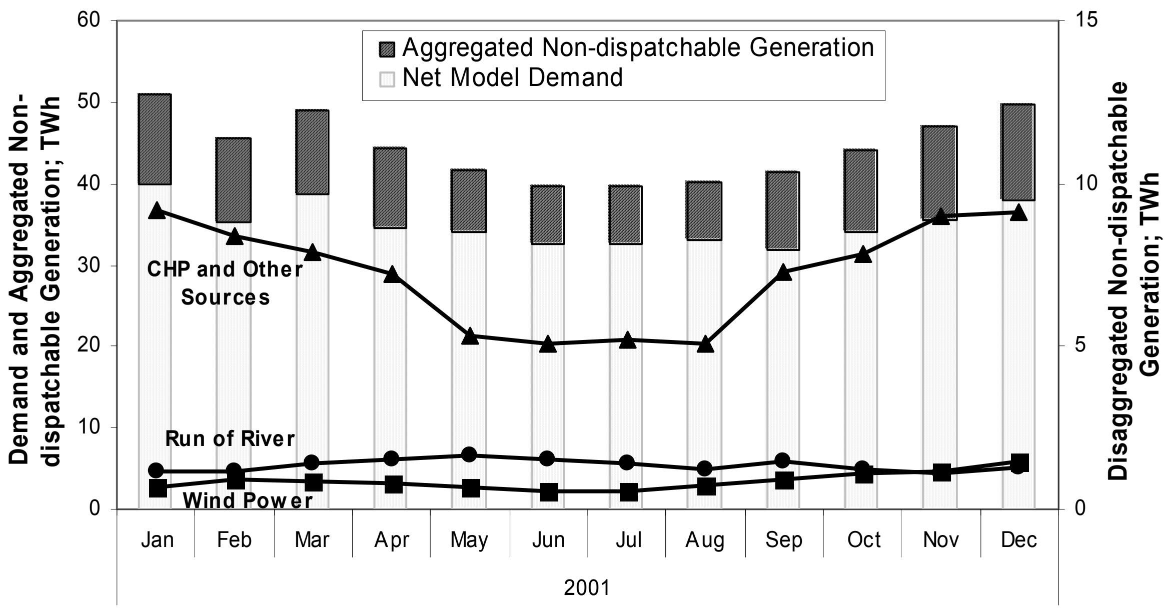



Figure 9 illustrates monthly demand data for Germany. Total demand is covered by non-dispatchable sources and "regular generation" optimized by the model. The corresponding axis for columns of model generation and aggregated non-dispatchable energy is on the left of Figure 9. Non-dispatchables energies are the aggregate of wind power generation, run of river generation, combined heat and power generation, and energy generated by other sources. Disaggregated generation by these energy sources is also shown (in lines) and corresponds to the right axis of the figure.

**Figure 9: Monthly Model Demand and Generation by Non-dispatchable Energies, Germany 2001**



Some facts are noteworthy about the data in Figure 9. Firstly, demand in February seems to be low. However, this is simply caused by using unweighted monthly figures. Since February 2001 had 28 days, total energy consumption was naturally lower than in January and March. Secondly, both run of river and wind power generation were very volatile. Favorable wind conditions at the end of the year and additional installed capacity led to more wind than run of river generation. Thirdly, total demand as well as residual model demand during the summer was much lower than during the winter months.

Demand data is derived from different publications by the Federal Statistical Office Germany[20] in connection with UCTE's hourly load profiles. Annual and monthly electricity consumption figures for other model regions are often published by national statistical offices. Additional data for many regions can be found at the regulators' home pages. Information on industrial CHP generation in Germany is made available by VIK. In addition, the lag of published data on CHP generation is partially solved by using another model of EWI[21]. Data on monthly wind power generation were provided by ISET e.V.

**Algebraic Structure of the Model**

Kreuzberg (2001) describes the algebraic structure of the model to great detail. However, the model has grown and improved since 2001. In addition, the data and the model's algebra are crucial for our analysis. For these reasons, we present and briefly explain the model's main equations in this appendix. Following Kreuzberg, we start with the cost equations and then present the most important constraints.

The cost equations are the natural starting point for a description of the model algebra since the objective function is cost minimization:

**(1)** $$C = VC^{On} + VC^{P} + VC^{T} + VC^{I} \rightarrow Min!$$

All relevant costs enter the objective function. Relevant costs comprise start-up costs ($VC^{On}$), variable operation costs ($VC^{P}$), variable transmission costs ($VC^{T}$) and variable costs of imports from non-model regions ($VC^{I}$). All four cost variables on the right side of equation (1) are determined by other equations. However, we will focus on the first three components since the cost equations for imports from non-modeled regions are of less importance in this context.

Equation (2) represents start-up costs in the whole system, i.e. total start-up costs of all stations started up in a certain week, in all regions (reg), all technologies (tech), all vintages (v)[22], during each type of day (dayt)[23] and for each load level (lh)[24]. CAPOn is the capacity

20 One example is Statistisches Bundesamt (ed.), 2000-2003.

21 A description of this CHP model called CEEM can be found http://www.ewi.uni-koeln.de.

22 Power plants of the same technology are aggregated in vintage classes of five years. For example, all German hard coal fired capacity built between 1980 and 1984 is in vintage class 1985.

23 Remember that workday, Saturday and Sunday and distinguished.

started up in a certain load level and sc are station and load level specific start-up costs of this capacity. Start-up costs (*sc*) comprise both attrition costs and fuel costs. The costs of starting up a plant depend on the type of technology and the history of utilization of the capacity. At this point, a remark on the intertemporal optimization of start-up costs should be made. The model optimizes load duration curves instead of chronological load curves. Start-up decisions are optimized under the assumption that plants started up during a certain load level are available during all higher load levels. This is a simplification especially when a load curve has not only a global but also at least one additional local maximum.[25]

**(2)** $$VC^{On} = \sum_{reg}\sum_{tech}\sum_{v}\sum_{dayt}\sum_{lh} CAP^{On}_{reg,tech,v,dayt,lh} \cdot sc_{tech,v,dayt,lh}$$

Equation (3) shows the costs of power production once the station is started up. These comprise specific fuel costs (*fc*) and other variable costs (*o*) multiplied by the load output ($P^G$). Specific fuel costs are determined by the ratio of fuel prices ($\phi$) and a station's efficiency ($\eta$).

**(3)** $$VC^{P} = \sum_{reg}\sum_{tech}\sum_{v}\sum_{dayt}\sum_{lv} P^{G}_{reg,tech,v,dayt,lv} * \left(fc_{reg,tech,v} + o_{reg,tech,v}\right)$$

with

$$fc_{reg,tech,v} = \frac{\phi_{reg,tech}}{\eta_{reg,tech,v}}$$

Equation (4) gives the costs of power transmission between model regions. These costs comprise the national grid entry costs (production $P^G$ times the national entry rate $\tau_{reg,reg}$) and the costs of cross-border exchange ($P^T$ times the cross-border tariff rate from region *r* to region *reg*, $\tau_{r,reg}$).

**(4)** $$VC^{T} = \sum_{reg}\sum_{dayt}\sum_{lv}\left(\sum_{r} P^{T}_{r,reg,dayt,lv} \cdot \tau_{r,reg,lv} + \sum_{tech}\sum_{v} P^{G}_{reg,tech,v,dayt,lv} \cdot \tau_{reg,reg,lv}\right)$$

The first step in the analysis of a linear programming problem is the understanding of the objective function. The next step naturally tackles the numerous constraints. The most important constraints are presented in equation (5) to (13).

The demand constraint (equation (5)) states that gross load (*l*) in each region and every moment has to be covered by generation and imports. Domestic generation, $P^G$, minus electricity consumption of domestic pump storage stations, $P^P$ is domestic net production. The power exchange balance of imports and exports ($P^T_{r,reg}$ $+P^I_{satreg,reg}$ $-P_{,reg,r}$) is the second source to cover demand. Imports are reduced for transmission losses ($\nu^T$). Transmission losses amount to approximately 10% per 1000 km of average transportation distance ($\delta$) independent of the

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24 24 different hourly load levels are distinguished for every type of day.

25 Kreuzberg (2001) analyzes the simplifications of load duration curves to great detail on p. 61 ff.

utilization level of the interconnectors. It has been pointed out that international power exchanges are assumed to follow contract paths. This is used in equation (5). The only limiting factors for power flows between regions are available net transfer capacities (NTC). These NTC values ($\chi^T$) can be adjusted varying their availability ($\alpha^T$) as shown in equation (6).

**(5)**

$$\begin{aligned}
&\sum_{tech}\sum_{v} P^G_{reg,tech,v,dayt,lv} - \sum_{v} P^P_{reg,v,dayt,lv} \\
&+\sum_{r}\left(1-\upsilon^T_{r,reg}\right)\cdot P^T_{r,reg,dayt,lv} - P^T_{reg,r,dayt,lv} + \sum_{satreg}\left(1-\upsilon^T_{satreg,reg}\right)\cdot P^I_{satreg,reg,dayt,lv} - \varepsilon_{reg,satreg,dayt,lv} \\
&\geq l_{dayt,lv,reg}
\end{aligned}$$

$$\text{with} \quad \upsilon^T_{allreg,allr} = \frac{0.1}{1000}\cdot\delta_{allreg,allr}$$

**(6)** $$P^T_{reg,r,dayt,lv} \leq \alpha^T_{reg,r,dayt,lv}\cdot\chi^T_{reg,r}$$

In addition to serving load on the regular market, power plants have to provide reserve and balancing requirements. This can be seen in equation (7) which essentially states that generation plus potential reserve provision cannot exceed the amount of capacity started up, or, in other words, that is turned 'on'.

**(7)** $$P^G_{reg,tech,v,dayt,lv} + R_{reg,tech,v,dayt,lv} \leq \sum_{lh|lm\neq 0} CAP^{On}_{reg,tech,v,dayt,lh}$$

We start the analysis of equation (7) on the right side. $CAP^{ON}$ describes the amount of capacity started up and ready for use. How much capacity can be started up at all? This is restricted by equation (8). Capacity started up cannot exceed the available share ($\alpha^G$) of installed generation capacity ($\chi^G$). The availability of capacity is below one for two reasons. Firstly, stochastic outages restrict availability of installed capacity. Secondly, plants have to shut down for repair and maintenance. In contrast to stochastic outages, plant shut downs for maintenance purposes may be scheduled according to expected opportunity costs. For example, base load plants are usually revised during the summer when electricity prices tend to be lower than during the winter. If maintenance could be adjusted according to opportunity costs, it should be optimized endogenously by a good dispatch model. However, maintenance has to be organized with a relatively long planning horizon. It can be assumed that last years maintenance schedule is reasonably close to next years expectedly optimal schedule. In addition, the number of maintenance teams is restricted. A pure model based optimization of maintenance might violate this constraint. For these reasons, maintenance decisions and stochastic outages are combined in an exogenous factor $\alpha^G$.

**(8)** $$\sum_{lh} CAP^{On}_{reg,tech,v,dayt,lh} \leq \alpha^{G}_{reg,tech,v} \cdot \chi^{G}_{reg,tech,v}$$

Equation (9) turns back to the reserve restrictions on the left side of equation (7). The parameter $\chi^R$ in this equation determines the amount of primary and secondary reserve which has to be provided. The *resmod* index distinguishes primary and secondary reserve. $R^{eff}$ is the amount of capacity which can effectively provide reserve. Technical constraints on a station's ability to quickly vary load may impose binding constraints especially for the provision of primary reserve. Hence, $R^{eff}$ might be less than the fraction of capacity of a station turned 'on'.

**(9)** $$\sum_{tech} \sum_{v} R^{eff}_{reg,tech,v,dayt,resmod,lv} \geq \chi^{R}_{reg,dayt,resmod}$$

Another important restriction is the minimum load constraint in equation (10). This equation states that there is a lower limit for plants operated in partial load modus. Usually, utilization of capacity started up is not allowed to fall below 60%.

**(10)** $$P^{G}_{reg,tech,v,dayt,lv} \geq \pi^{min}_{tech,v} \cdot \sum_{lh} CAP^{On}_{reg,tech,v,dayt,lh}$$

A focus of the analysis in this paper is on the dispatch of storage plants. For that reason, the relevant equation for these plants, and especially the pump storage plants, are described. Pump storage plants are optimized in a weekly cycle. An additional constraint contains a maximum load factor per day which is included to capture limited reservoir sizes. Equation (11) determines the storing of electricity in the form of pumped water. An energy budget $Q^{max,PS}$ (left side) is stored by consuming electricity for pumping (right side). Note that both sides of this equation are endogenous variables.

**(11)** $$Q^{\max,PS}_{reg,v} \leq \sum_{dayt} \sum_{lv} P^{P}_{reg,v,dayt,lv} \cdot \eta_{reg,"hyd\_PS",v}$$

Equation (12) determines the use of the energy stored in $Q^{max,PS}$:

**(12)** $$\sum_{dayt} \sum_{lh} CAP^{On}_{reg,tech,v,dayt,lh} \leq Q^{\max,PS}_{reg,v}$$

Finally, equation (13) states a general fuel constraint for plants. $\theta$, the fuel budget, is usually not set to binding values except for storage hydro plants. In some cases it might be required to set a binding value for lignite if the pit capacity could not provide the amount of lignite the station would burn in the unconstraint dispatch.

**(13)** $$\sum_{dayt} \sum_{lh} \frac{CAP^{On}_{reg,tech,v,dayt,lh} \cdot dh_{dayt,lh}}{\eta_{reg,tech,v}} \leq \theta^{\max}_{reg,tech}$$

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