Market power in the Nordic electricity wholesale market: A survey of the empirical evidence*

by

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Abstract

We review the recent empirical research assessing market power on the Nordic wholesale market for electricity, Nord Pool. The studies find no evidence of systematic exploitation of system level market power on Nord Pool. Local market power arising from transmission constraints seems to be more problematic in some price areas across the Nordic countries. Market power can manifest itself in a number of ways that have so far escaped empirical scrutiny. We discuss investment incentives, vertical integration and buyer power, as well as withholding of base-load (nuclear) capacity.

Keywords: Market power; hydro power; transmission constraints

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1 Introduction

Norway liberalized its electricity sector in 1991. Sweden and later Finland and Denmark followed suit and by the end of the decade the Nordic countries had formed the first multinational power exchange, *Nord Pool*. Despite its apparent success in attracting new member countries, concerns have been raised about the Nordic power market's actual performance.[1] Do the large generation companies exploit market power, thereby harvesting excessive profits? Or do the prices merely reflect fuel prices, emission costs and energy taxes?

In light of the public dissent about the performance of the Nordic electricity market, we review the recent empirical studies of market power on Nord Pool. These studies try to quantify the extent to which the electricity wholesale prices can be explained by generation companies exploiting market power.[2] We summarize the findings, evaluate the results and discuss unresolved issues of potential importance for market power in the Nordic market.

In Nord Pool, supply and demand clear at different levels. The *system price* refers to the equilibrium price that would prevail in a fully integrated market. Bottlenecks in transmission, however, frequently prevent full price equalization. When this happens, the Nordic market is divided into regional price areas. Firms can thus exercise market power at both the system level and in the regional price areas.

The predominance of hydro power is a characteristic feature of the Nordic electricity market. In a normal year, hydro power stands for half of the Nordic electricity production. Hydro power markets function differently from other power markets. In a hydro power plant, management must decide how to allocate production across periods since aggregate production is limited by the size of the power plant's reservoir. The more the reservoir is drained in the autumn the less the power plant is able to produce when the winter comes. Any proper evaluation of hydro power markets must take account of this *inter-temporal* aspect.

A firm exercises market power if it engages in strategic manipulation of its prices to raise its profits. Market power drives a wedge between price and marginal production cost. In a hydro power plant, marginal production cost is the value of foregone future production. This opportunity cost of production, usually referred to as the *water value*, is unobservable. Estimating the water value is the main challenge facing any study of market power in the Nordic market.

The empirical models used to estimate market power in the Nordic electricity wholesale market fall in two main categories, *direct models* and *behavioural models*.[3] Direct models obtain water values by simulating the market; systematic price deviations from the simulated water values indicate market power. An advantage of this approach is its explicit account of

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[1] In 2006, the Committee on Industry and Trade in the Swedish Parliament held a public inquiry into the electricity market. The inquiry was partially motivated by the recent years' sharp increase in electricity prices; see http://www.riksdagen.se/upload/Dokument/utskotteunamnd/200506/NU/RFR9_0506.pdf for an account of the views expressed.

[2] For an empirical analysis of market power in the electricity *retail* market, see Hansen and von der Fehr (2009).

[3] There is even a third category, known as *structural models* (Twomey et al., 2005). Competitiveness is evaluated on the basis of structural variables thought to be related to market power, concentration of generation capacity being a leading example. Structural methods can say something about the potential for market power, but nothing about the extent to which market power is actually exercised. We therefore skip these analyses, but refer to Ilonen (2005), Twomey et al. (2005) or Vassilopoulous (2003) for detailed descriptions of the approach. See also Energimyndigheten (2006) for an application to the Nordic electricity market.

the dynamics of hydro markets. Behavioural models (Twomey et al., 2005) examine the observed prices and quantities. Statistical techniques are used to estimate marginal costs and market power given an assumed behavioural relation between observed input variables, prices and quantities. Under this approach marginal costs need not be estimated, although its essentially static approach is an obvious drawback. Market power is estimated separately across periods, a procedure which ignores the fundamental inter-temporal structure of hydro power markets.

Recent empirical studies of market power on Nord Pool find no evidence of blatant and systematic exploitation of system level market power. Absent bottlenecks, the market is either deemed competitive or the quantitative effects of market power are found to be small. Local market power arising from transmission constraints seems more problematic in some price areas across the Nordic countries.

It is time to look elsewhere than short-run deviations from competitive prices for evidence of market power. First, firms may have an incentive to under-invest in capacity to exercise long-run market power. Second, the Nordic electricity market holds the potential for an exploitation of vertical and buyer market power due to extensive vertical integration in retail and generation. Third, generation companies may have an incentive to reduce base-load nuclear power. These manifestations of market power do not drive a wedge between output prices and marginal production cost, and therefore cannot be quantified within existing models.

2 The Nordic electricity market

Starting with Norway in 1991 the Nordic countries gradually deregulated national generation and marketing of electricity. The Nordic countries (except Iceland) merged their wholesale markets into a common Nordic power market step by step: Sweden joined in 1996, Finland in 1998 and Western and Eastern Denmark in 1999 and 2000.

2.1 Institutional details

Prior to deregulation, each country had one large, state-owned utility. The utility also ran the high voltage transmission grid connecting the country’s regions. In addition, some regions had local vertically integrated monopolies, producing and distributing electricity in the region. The subsequent wave of deregulations eliminated the monopoly franchises for the generation and sale of electricity. Transmission and generation were separated, and independent National System Operators were established to manage the grid and balance the supply and demand of electricity.

A non-mandatory Nordic power exchange, Nord Pool, was created to organize the trade of wholesale electricity. Nord Pool consists of several markets. The cornerstone market is *Elspot*, a day-ahead market for the physical delivery of electricity in which hourly supply and demand bids for the next day are aggregated and matched. This generates a market clearing price, the *system price*. Absent transmission constraints, all electricity is traded at the system price. The institutional details for handling transmission constraints differ across countries. In Norway and Denmark, the market is divided into several geographical price areas with potentially different market clearing prices. The other countries handle bottlenecks through counter purchases.

Nord Pool combines Elspot with both a financial market and *Elbas*, a market for continuous power trading up to the hour prior to delivery. The financial market trades power derivatives such as futures, forwards and options. Financial contracts can be used to hedge electricity prices, and their time horizons range from a single day up to three years. The system price determined in Elspot constitutes the reference price for the power derivatives traded on Nord Pool. The National System Operators handle the final matching of demand and supply in various real time markets.

2.2 Technologies

The Nord Pool area generated a total of 397 terawatt-hours (TWh) of electricity in 2007. Table 1 displays production in 2007 across the four countries. A striking feature of the Nordic market is its reliance on hydro power. Norwegian and Swedish hydro plants produce roughly half of the yearly generation. The remaining electricity is supplied by means of Swedish and Finnish nuclear power and by other sources of thermal power in Finland and Denmark.

	Denmark	Finland	Norway	Sweden	Total
Hydro power	0	14	135	66	215
Nuclear power	0	22	0	64	86
Other Thermal	30	41	1	14	86
Wind power	7	<1	1	1	10
Total	37	78	137	145	397

Table 1: Electricity generation (TWhs) in the Nord Pool area in 2007 (Source: Nordel, 2008)

2.3 Market structure

Many sellers and buyers participate in the Nordic wholesale market, but a few large players stand out. The four largest producers of electricity in the Nordic market–Vattenfall in Sweden, Fortum in Finland, Statkraft in Norway and Dong in Denmark–all date back to the era of regulation. An additional important player is the German entrant E.On. The concentration ratios are fairly small at the Nordic level; no producer has a market share beyond 20%. National market concentration is much higher, however. Transmission constraints may thus have important anticompetitive effects.

A second important feature of the Nordic power market is vertical integration: most generation companies also buy on the wholesale market.

3 Market power and its consequences

A firm exercises market power if it engages in strategic manipulation of its prices with the purpose of raising its profit. Electricity wholesale markets display a number of features which render the potential for exercising market power particularly high (Joskow, 2008): generation capacity is concentrated, demand is price insensitive, and capacity constraints in transmission create local markets and limit import possibilities.[4]

[4] Some claim that power markets are particularly vulnerable to market power because electricity cannot be stored. This claim is questionable for at least three reasons. First, electricity *is* sometimes storable insofar as water is storable and can be instantly converted into electricity. A recent contribution (Kauppi and Liski, 2008) explicitly treats electricity as a storable good. Second, markets with non-storable goods are not by necessity non-competitive. Standard models of imperfect competition (e.g. Cournot or Bertrand) assume non-storable goods. The intensity of competition in these models depends on the number of firms, the price sensitivity of demand, and product differentiation, not on non-storability. Third, storable good markets are not necessarily competitive. Dixit (1980) shows how storability allows an incumbent to soften competition. By investing in capacity or holding a large inventory, the incumbent can credibly commit to intense competition following entry. This can be sufficient to block entry altogether, leading to full monopolisation.

Market power takes many forms besides direct price manipulations, for example, quantity adjustments, entry deterrence and capacity investments. One cannot expect firms to admit to exploiting market power; a benchmark against which to test observed behaviour is necessary. The most widely used measures of market power are based on the difference between the output price and the *marginal production cost*, the cost of producing an additional unit.

A profit maximizing firm without market power increases its production until marginal production cost equals the output price. The strategic firm acknowledges that higher production leads to a lower output price; the marginal value of production is lower than the price. A profit maximizing firm exploiting market power increases its production until the marginal production cost equals the *marginal revenue*–the marginal value of production. A wedge between the output price and marginal production is thus a sign of market power.

The imperfectly competitive solution is inefficient because it leads to under-consumption; some consumers whose valuation exceeds the marginal cost of supplying the product are excluded from buying it. The deadweight loss of market power equals the difference between the excluded consumers' willingness to pay and the marginal cost of meeting their demand. The price-cost margin is an inappropriate measure of the welfare costs of market power because it holds no information about the magnitude of under-consumption.

Market power in a hydro-thermal system[5] In a hydro-thermal system, production is limited by the reservoir capacity. To expand production in one period, production needs to be contracted in other periods. Consequently, production decisions are linked across periods, they are *inter-temporal*. We illustrate this problem in Figure 1:

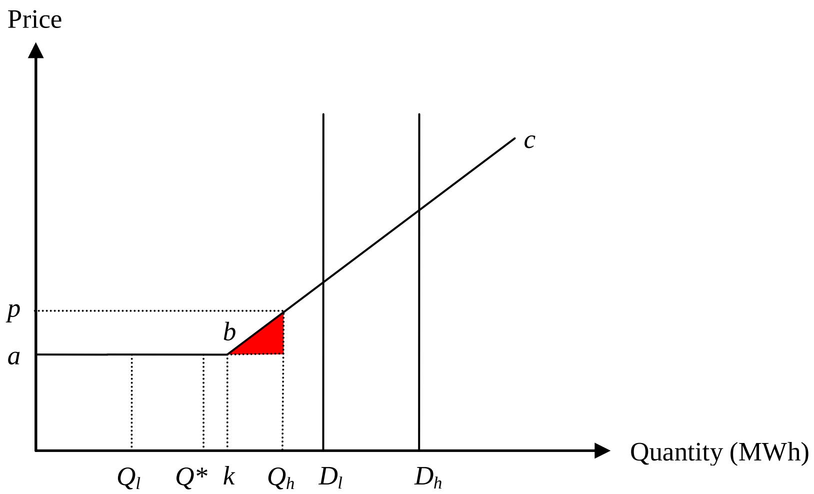

Figure 1: Market power in a hydro-thermal system

Assume a competitive supply of thermal power. Thermal supply then equals the marginal thermal production cost *MPC*, the line segment *abc* in Figure 1. Base-load, say nuclear power, is produced at constant marginal cost *a* up to capacity *k*. *MPC* increases thereafter with the activation of increasingly costly fossil fuel technologies. There are two periods, one characterized by high (peak) demand, and the other by low (off-peak) demand. For simplicity, demand is assumed to be insensitive to prices, i.e. *inelastic,* in both periods, with peak and off-peak demand given by D_h and D_l. Suppose thermal production equals Q_h in the high demand period, but only Q_l in the low period. Hydro production covers residual demand, D_h-

[5] For a textbook treatment of the economics of hydropower, see Førsund (2007).

Q_h and D_l-Q_l in the high and low period, respectively. The peak price exceeds the off-peak price, p versus a, in this case owing to the activation of costly peak fossil fuel production.

Assume also a competitive supply of hydro power, i.e., hydro producers are price takers. Each producer must decide how much hydro power to allocate to each period. Since the peak price exceeds the off-peak price, transferring hydro production from the low to the high demand period is profitable. This reallocation occurs until the prices in both periods are equalized, at thermal production Q^* and price a in Figure 1 We draw two conclusions about competitive hydro markets. Absent capacity constraints, water balances fluctuations in demand meaning that (*i*) prices are equalized and (*ii*) thermal marginal production costs are equalized across periods.

Assume instead that hydro producers are strategic. In this case, price equalization is not profitable. At the competitive solution Q^* in Figure 1, hydro power is sold at a in both periods. By reallocating hydro from peak to off-peak, hydro producers are able to raise the peak price of electricity to p and thereby sell the total quantity of hydro power at an average price above a.

Equalization of price and marginal cost across periods leads to cost minimization of thermal production in the competitive equilibrium. With hydro market power, costs are not minimized since prices fluctuate excessively with demand. The cost of market power can be read directly from Figure 1. There are Q_h-k MWhs of electricity excessively produced by fossil fuel burners, at extra cost equal to the shaded area. Note also that the price difference p-a between peak and off-peak cannot capture the welfare loss of market power, as it contains no information about the amount Q_h-k of electricity that is produced inefficiently.

Market power in generation transfers wealth from consumers to producers. Whether this redistribution constitutes a welfare loss depends on how profits are valued in relation to the consumer surplus.

Note also that marginal cost pricing is a short-term competitive benchmark. With fixed production costs, the average cost may in equilibrium be higher than the marginal cost. In this case, the producers would run a deficit at the competitive solution. The relevant benchmark associated with long run profitability is then average cost pricing, not marginal cost pricing.

Key to the problem of estimating hydro market power is how to estimate the water value. In a competitive market with profit maximizing firms, the water value equals the discounted future expected spot price. The prices of forward contracts for electricity provide estimates of the expected spot price. Yet these forward prices are reasonable measures of the competitive water values if and only if the markets are indeed competitive. If not, the forward prices will reflect future market power. Thus, the difference between forward prices and spot prices is not an appropriate measure of market power. One is therefore forced to consider alternative, production based, measures. One way of testing for hydro market power is to compare actual *reservoir levels* with competitive ones. In the Nordic market, reservoirs are filled during the summer and autumn and drained during the winter and spring. Over-production in the off-peak summer season would materialize as insufficient reservoir levels in the peak winter season.

4 Estimation

Market power in generation drives a wedge between the wholesale price of electricity and its marginal production cost. The studies estimating market power in the Nordic countries mainly attempt to quantify this wedge. Figure 2 illustrates the problem of estimating market power.

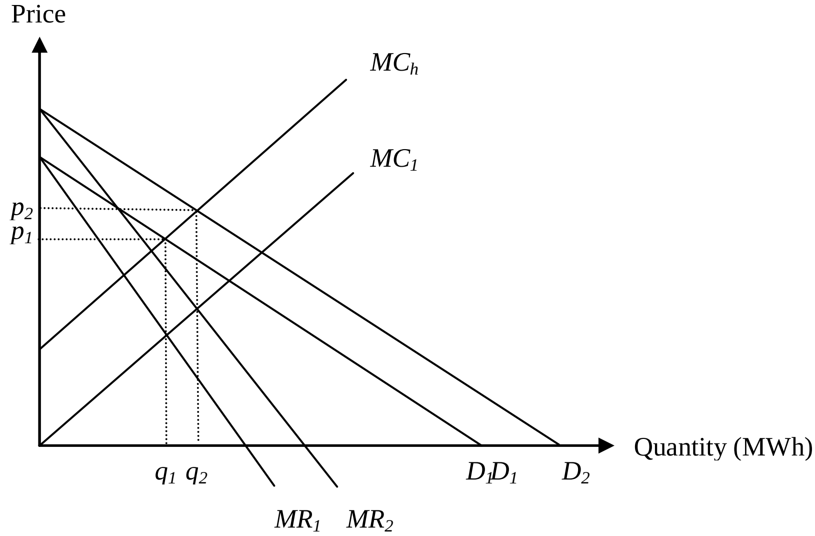

Figure 2: The problem of estimating market power

The observed price/quantity pairs (p_1,q_1) and (p_2,q_2) reveal nothing about market power because both are consistent with perfect competition as well as full monopoly. They are consistent with perfect competition if the marginal cost is high and given by MC_h. All price and output variation stems from demand fluctuating between D_1 and D_2. Monopoly prevails if the marginal cost is instead given by MC_l. Demand fluctuations then yield exactly the same observations.

The empiricist must address three methodological problems when estimating market power in the Nordic electricity wholesale market. First, she has to separate out the effects of market power on price and output from those stemming from fluctuations in demand and marginal cost. Second, the researcher needs to handle the inter-temporal decision problem associated with hydro power production. The cost of producing hydro power is essentially its opportunity cost, the *water value*: water poured out of the reservoir today cannot be used for production tomorrow. Thus, production is linked across time. Third, the researcher must define strategies for handling transmission constraints. Transmission bottlenecks create local opportunities for exercising market power. This third choice determines to a large extent the scope of the study. The empirical models applied to the Nordic electricity wholesale market fall into two main categories, *direct models* and *behavioural models*.

Direct models estimate marginal production cost based on industry data and then compare the estimates to observed market prices. Systematic deviations are taken as a sign of market power. The dynamics of hydro production are modeled explicitly, and water values are computed. One disadvantage is that detailed production data are necessary. Some of the studies take transmission constraints into account; others disregard them, focusing on market power at the system level only.

Behavioural models (Twomey et al., 2005) examine the observed prices and quantities. Statistical techniques are used to estimate marginal costs and mark-ups given an assumed behavioural relation between observed input variables, prices and quantities. Behavioural models may have less demanding data requirements, but are sensitive to underlying behavioural assumptions. They are essentially static, ignoring the dynamics of hydro power markets. Some of the studies focus on transmission constraints; others ignore them.

4.1 Direct models

Engineering data can be used to generate reliable cost estimates for thermal production. Fuel costs constitute the main cost component for nuclear and fossil fuel plants. The heat rate measures the efficiency with which fuel is converted into energy and is available for a number of plants. Multiplying the heat rate by fuel prices allows for reliable estimation of the fuel cost component. Consequently, industry marginal cost functions are readily available for electricity markets relying primarily on nuclear and fossil fuel technologies.[6]

Estimating the marginal cost of hydro-electric production is more complicated because this cost mainly consists of the unobservable value of postponing production. Opportunity cost or water value estimates are obtained by simulating the market. Typically, water is allocated across periods by means of a stochastic dynamic programming procedure to maximize the expected social welfare over the period. Given the benchmark production and reservoir levels, one can compute a competitive water value. Hydro-electric production is deemed competitive if the observed spot price is equal to the simulated water value.

Simulating the optimal hydro production involves estimating reservoir inflow distributions and demand functions. Inflow distributions are computed based on long time-series of historical inflow. All simulation studies on the Nordic market take the same short-cut to estimating demand: the demand function is assumed to be vertical (price-inelastic) and equal to observed output at every point in time.

The variation of water values across hydroelectric power plants further complicates the analysis. A plant with a large reservoir and a small turbine capacity displays a low water value because it can run at full capacity for a long time without significantly affecting its future production possibilities. Conversely, if a plant has only a small reservoir and large turbine capacity, its short term production plans may significantly affect its future production possibilities. All else equal, this plant has a high water value. Furthermore, the water inflow may vary across plants as a function of local climatic and geographical conditions, thereby affecting the water value. Ideally, one would like to model each hydroelectric power plant separately in order to properly account for the distribution of water values. Such a level of detail is, however, computationally impossible to handle. The simulation models differ in the level of detail with which they model reservoir and turbine capacity.

4.1.1 Model descriptions

4.1.1.1 The model by Olli Kauppi and Matti Liski

Olli Kauppi and Matti Liski at the Helsinki School of Economics have constructed a simulation model of the Nordic electricity market with the purpose of estimating market power in a storable goods industry (Kauppi and Liski, 2008). Hydro power is a storable good insofar as the power plants under consideration have water reservoirs.

[6] Classical studies have used this direct estimation method to measure market power in the California electricity market (e.g., Borenstein et al., 2002; Joskow and Kahn, 2001) and the UK electricity market (Wolfram, 1999). The empirical evidence is mixed. The studies on the California electricity market found evidence of market power while Wolfram's study found only a limited amount of market power in the UK.

The Kauppi-Liski model focuses on hydro market power. Thermal supply is estimated on the basis of seasonal variation and the price of fossil fuels. The Kauppi-Liski model is simulated on weekly averages of the system price. The system price is the market clearing price for the integrated Nordic market, i.e., the price that would prevail absent transmission bottlenecks. The potential anticompetitive effects of transmission constraints cannot be assessed within this model. The model simplifies hydro technology by aggregating all reservoir capacity into one big reservoir and all turbine capacity into an aggregate turbine capacity. Effectively, all hydro power plants are assumed to have the same technologies and inflows, but of different scales.

4.1.1.2 The BID model by Econ-Pöyry

The BID model, owned by the consulting company Econ-Pöyry, was developed to analyse the profitability of generation and transmission investments. Econ-Pöyry has later modified BID to incorporate market power issues (Damsgaard et al., 2007).

The BID model uses engineering data to estimate marginal cost curves for nuclear and fossil fuel plants. BID even includes start/stop costs for thermal power production. The BID model has an hourly resolution, in accordance with Nord Pool´s Elspot market, and can handle regional price areas. Consequently, transmission constraints are accounted for to some extent. Hydro power is aggregated across price areas, with an aggregate reservoir level and aggregate turbine capacity for each area. BID accounts for plant variations by assuming a distribution of the water value around the area mean.

4.1.1.3 The PoMo model by EME Analys

PoMo is the property of the consulting firm EME Analys. It is primarily used to forecast electricity prices, but it has also been used to evaluate prices in relation to marginal costs in the Nordic market (Edin, 2001 and 2006).

Marginal cost curves for thermal production are estimated from engineering data. PoMo forecasts weekly system prices. Reservoir levels, inflow and turbine capacity are aggregated into one large hydro production plant. PoMo accounts for plant variations by assuming a distribution of the water value around the mean.

4.1.1.4 Additional models

A number of additional stochastic dynamic programming simulation models are potentially useful for evaluating market power; see Ilonen (2005) for a detailed description.

The *EMPS* model (Samkjøringsmodellen), marketed and maintained by the consulting firm Powel, models hydro power in the Nordic market in the greatest detail. It is divided into a number of regional subsystems, each incorporating transmission constraints and hydrological differences. The EMPS model builds on the assumption of competitive pricing and is primarily used for spot price forecasting. EMPS has also been used for market power estimation, but the reports are confidential and we have not had access to them.

The *MARS* model was developed by Eltra, the agency previously responsible for system operation in western Denmark. The model allows strategic pricing of thermal production, but can also be run as a competitive model. MARS takes its water values from the EMPS model.

Balmorel is a simulation tool for electricity pricing in the Baltic Sea region. It is an open-source model, financed by the Danish Energy Research Program. Balmorel can simulate imperfect as well as perfect competition.

4.1.2 Findings

Kauppi and Liski (2008) find that hydro producers systematically over-produced during summers and under-produced during winters compared to the social optimum during 2000-5. This tended to create excessive price fluctuations; see Figure 3.

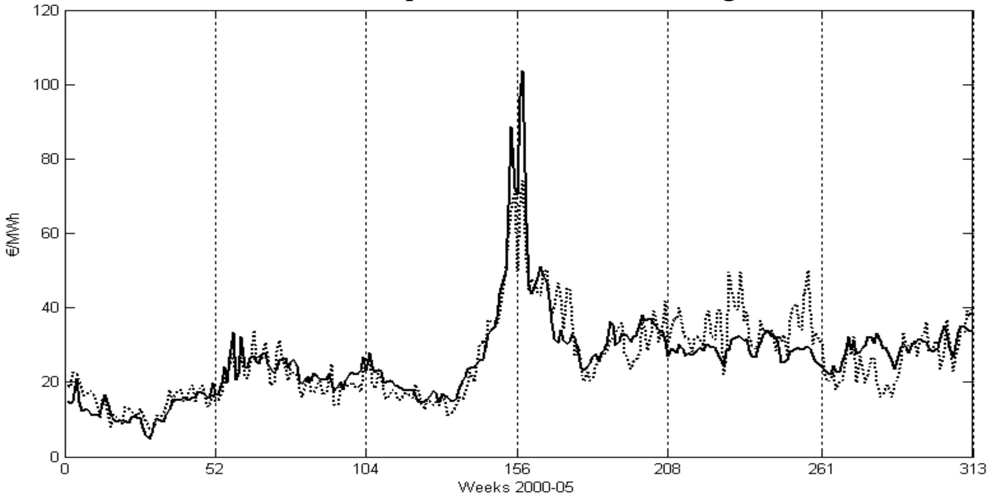

Figure 3: Observed (solid) vs. simulated (dashed) system price (Kauppi and Liski, 2008)

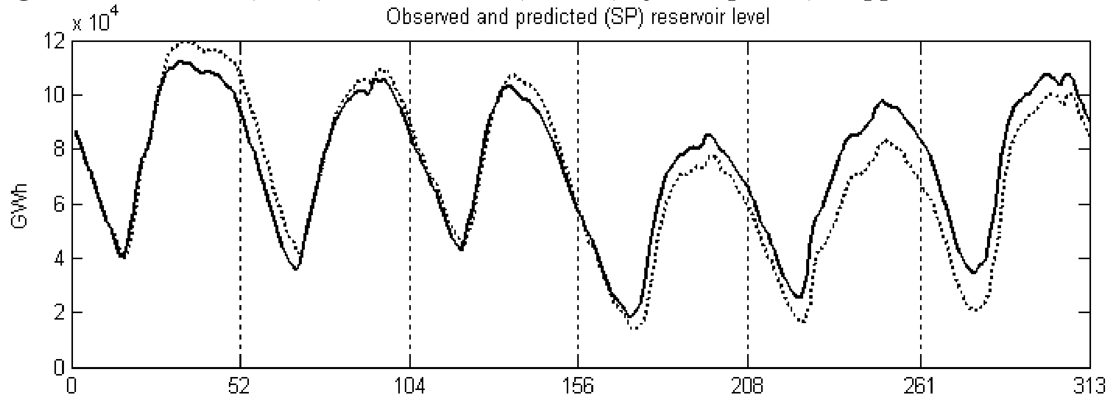

Figure 4: Observed (solid) vs. simulated (dashed) reservoirs (Kauppi and Liski, 2008)

Kauppi and Liski claim that reservoir levels for the most part were too low during autumn and winter compared to the competitive benchmark. They attribute this pattern to the exercise of market power. They also show that a simulation model in which one strategic producer controls 30% of the hydro capacity better fits the data than the model with competitive hydro production. As can be seen from Figure 4, insufficient reservoir levels seem to be more of a problem for the first part of the period than the later. On the contrary, reservoir levels appear to have been too high from 2003 and onwards.

The BID model was tested for two water shortage periods, summer to winter 2002-3 and summer to autumn 2006, and a normal period with normal reservoir levels, summer and autumn 2001 (Damsgaard et al., 2007). Table 2 reports the results.

	Deviations from the modeled (competitive) price		
Area	Summer-autumn 2001	Summer-winter 2002-03	Summer-autumn 2006
Sweden	-5%	-12%	12%
Norway	-9%	-13%	12%
Finland	-16%	-15%	10%
Jutland	-5%	18%	6%
Zealand	-2%	-6%	6%

Table 2: Deviations from the competitive price (Damsgaard et al., 2007)

The BID model simulations for the 2002-3 period are consistent with a market power scenario in which overproduction in the autumn initially drives prices below the competitive level, and yields inflated prices thereafter. Table 2 shows that the average mark-up over the period was negative in most regions. Damsgaard et al. (2007) argue that for the period as a whole, the price profile was probably unprofitable and not a sign of market power. An exception is the Jutland price area, with prices nearly 20% above and revenues 11% above the competitive level. In 2006, matters were different. From August on, prices were consistently above the competitive level in all price regions. Nonetheless, no strong conclusions are drawn regarding market power in 2006, as unanticipated shocks to reservoir levels could have contributed to the results. The normal situation of 2001 exhibited no signs of market power; production consistently exceeded the estimated competitive level.

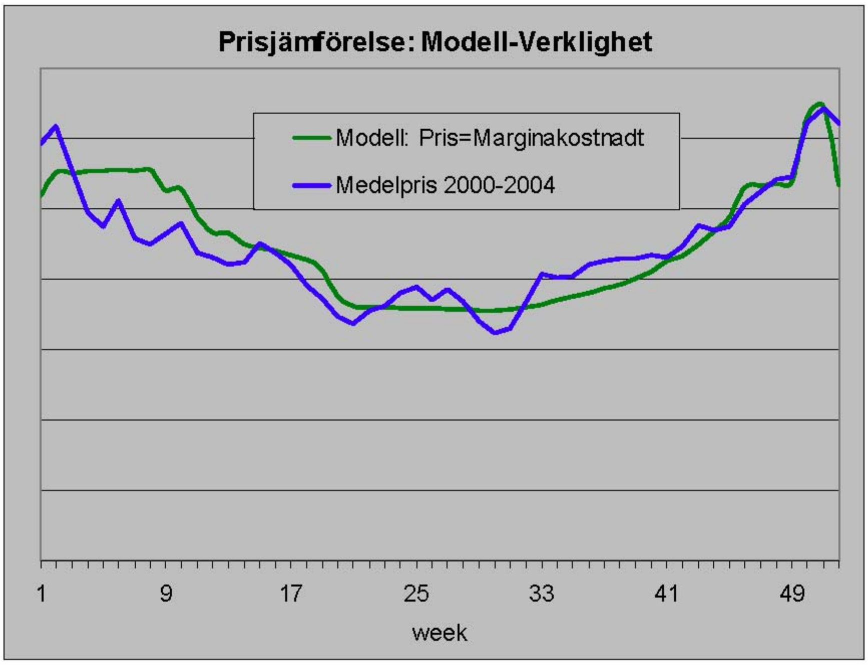

Figure 5: Price comparison average and estimated system price (Edin, 2006)

The PoMo model has been simulated for the periods 1996-2001 (Edin, 2001) and the period 2000-4 (Edin, 2006). Figure 5 shows the price simulation results for the latter period. The average system price was above the competitive level from late summer (week 32) until mid winter (week 3) and below the competitive level the rest of the time. Edin (2001 and 2006) considers the estimated price differences sufficiently modest to render the Nordic power market competitive.

4.1.3 Evaluation

The three simulation models, Kauppi-Liski, BID and PoMo, paint a consistent picture of the Nordic power market. There is evidence to suggest that hydro producers drain their reservoirs during the summer and enter the cold season with insufficient reservoir capacity. Typically, prices lie below the competitive level in summer and early autumn, but tend to rise in the cold season. Moreover, transmission constraints may lead to local market power, as exemplified by the case of Jutland in 2002-3. However, Damsgaard et al. (2007) question whether the observed behaviour really is a sign of market power. Overall, firm revenues tend to be below the competitive level, which may render actual behaviour unprofitable.

Which implications can be drawn about the welfare effects of the producers' decisions? As all three simulation models assume price-independent demand, none of them can capture any inefficiencies stemming from under-consumption. Welfare losses due to misallocation of production can potentially be estimated. When hydro production is inefficiently shifted from peak to off-peak periods, thermal production is de facto shifted the other way, from off-peak to peak. Of the three simulation models above, only Kauppi and Liski (2008) attempt to quantify the welfare loss of inter-temporal substitution of thermal power. They estimate the welfare loss of market power to be roughly 7 per cent, or 600 million Euros, during 2000-5.

Reliable plant capacity numbers are crucial to the measurement of industry marginal cost for fossil fuel plants. Scheduled and unscheduled maintenance stops pull down the effective capacity utilization and render nameplate capacities of limited use. PoMo and BID use historical capacity utilization to measure effective capacity. However, thermal production may have been reduced in the past for market power reasons. If so, industry marginal costs based on historical capacity utilization will lead to an upward bias of marginal costs and, as a result, a downward bias in market power.

Kauppi and Liski (2008) avoid the problem of estimating thermal capacity utilization by focusing entirely on market power in hydro production. They estimate thermal supply rather than marginal costs. It follows that Kauppi and Liski do not analyse industry market power, but rather market power for a subset of the production plants, namely hydro. This renders estimation of the optimal hydro production more difficult. Welfare maximization requires equalization of marginal cost of thermal production across periods. In the absence of thermal market power, this is the same as equalizing electricity prices across periods. If, instead, thermal production is subject to market power, price equalization does not generally imply cost minimization. Figure 6 illustrates this effect.

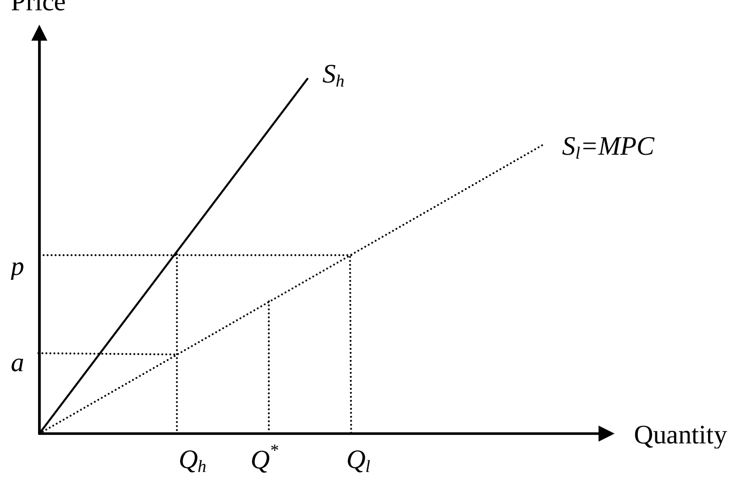

Figure 6: Price equalization with market power in thermal production

Here, thermal producers exercise market power when demand is high, but not in low demand periods. Off-peak thermal supply S_l then equals the thermal marginal production cost *MPC*, whereas peak thermal supply is below the competitive level, at S_h. Suppose hydro is allocated across periods to equalize prices, say at p. Since peak marginal thermal production cost equals $a<p$, it would be socially optimal to expand peak production from Q_h to Q^* and reduce off-peak production from Q_l to Q^*. This is achieved by shifting hydro production from the periods with peak to off-peak demand. By failing to take thermal market power into account, the model simulations in this case overstate the optimal peak hydro production and understate the optimal off-peak production. Competitive reservoir levels would then be upward biased.

Most thermal production technologies incur start-up or shut-down costs. With such *ramping costs*, even thermal production decisions are inter-temporal. There is a welfare gain of maintaining production relatively constant for each plant. By ignoring ramping costs, one inevitably underestimates the value of off-peak thermal production and overestimates it in periods of peak demand. This results in an overestimation of peak market power and an underestimation of off-peak market power.[7] The BID model accounts to some extent for ramping costs, whereas PoMo ignores them. Ramping is less relevant in the Kauppi-Liski model as this model does not consider thermal market power.

Transmission constraints frequently break up the Nordic market into smaller regional markets. This may lead to local market power if some producers have a more dominant regional than Nordic position. System level analyses of market power, as in the Kauppi-Liski and PoMo models cannot capture local market power. Moreover, by neglecting transmission constraints, welfare analyses will generally overestimate the cost of market power.[8]

The opportunity cost of water usage varies across hydroelectric power plants as a function of reservoir size relative to turbine capacity and water inflow. By aggregating reservoir size and turbine capacity and inflow, simulation models overstate the flexibility of hydro production and reservoir size. Consequently, inter-temporal substitution of hydro production is more constrained in reality than in the simulation models. It is unclear how this affects socially optimal hydro production, but a valuable robustness check would be to investigate how the simulation results depend on the aggregation.

4.2 Behavioural models

Behavioural models start out from observed prices and quantities, applying statistical techniques to infer marginal costs and mark-ups given an assumed behavioural relation between observed input variables, prices and quantities. The most common behavioural assumption is profit maximization. Additional structure is placed on the econometric model, normally in terms of specific functional forms of the demand for and the marginal cost of producing electricity.

Several studies have applied behavioural models to the Nordic power market. Most of these studies are based on Bresnahan (1982) and Lau's (1982) econometric model for identifying market power.[9] In its simplest form, the model is static, positing two relationships. One

[7] Mansur (2008) shows that ramping costs can be significant. In an analysis of the Pennsylvania, New Jersey and Maryland market, he shows that a failure to account for ramping costs leads to an overstatement of the welfare cost of market power by a factor of four.
[8] Cho and Kim (2007) estimate that about 40% of the annual welfare loss in the California wholesale electricity market over the period 1998-2000 could be attributed to transmission constraints.
[9] An exception is Johnsen et al. (2004), to which we return below.

describes how the demand for electricity depends on the electricity price and observable demand shifting variables, such as temperature and day length. A common assumption is that demand depends linearly on price and the shift variables. The second relationship describes the supply of electricity–how the price charged by firms depends on their marginal cost and market power. Frequently, firms' marginal costs are assumed to depend linearly on the supplied quantity and other cost shifting variables, such as fuel prices and water inflows.

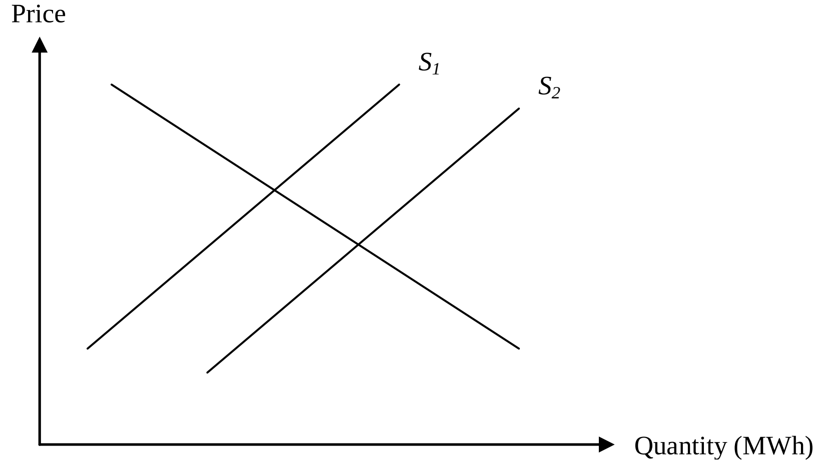

Figure 7: Estimating demand by means of supply variation

This framework can be used to estimate both the demand and the supply of electricity. Estimating the demand equation is straightforward as long as we have data on variables shifting only the firms' marginal cost and thereby the supply schedule. This is illustrated in Figure 7 where the supply curve shifts due to an observable change in, for example, the water inflow. As a result, two price and quantity combinations are observed and used to trace out the demand curve. Similarly, one can estimate the firms' supply curve by using observable changes in the variables shifting only demand.

The problem of estimating market power in the absence of a direct measure of marginal cost is how to separate the marginal cost component from the mark-up component in the supply relation. Bresnahan (1982) and Lau (1982) found conditions on the demand curve, allowing the marginal cost component to be isolated from the market power component in the supply curve. Market power can be identified provided the exogenous variables in the demand curve not only shift but also *rotate* demand.

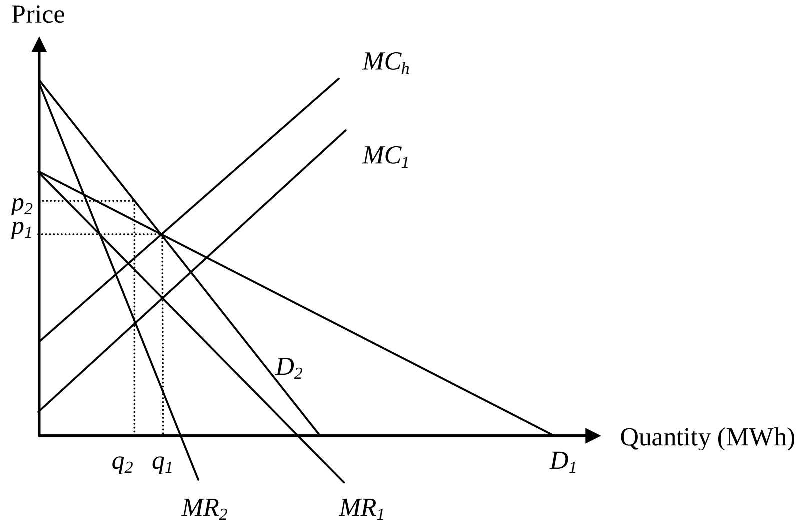

Figure 8: Using demand rotation to identify market power

An intuition for their result is provided in Figure 8. As in Figure 2, the price/quantity pair (p_1,q_1) is consistent with both perfect competition (high marginal cost) and monopoly (low marginal cost). Consider a shock rotating the demand curve around (p_1,q_1). Under perfect competition, when firms have high marginal costs, nothing should happen–price is still equal to marginal cost at (p_1,q_1). By contrast, a monopolist (with low marginal cost) will reduce its quantity to q_2 in order to raise price to p_2. These different responses to a demand shock enable an identification of mark-ups.

The four applications of the Bresnahan-Lau model to the Nordic power market employ a dynamic extension of the model initially proposed by Steen and Salvanes (1999). A dynamic model is suitable because firms submit bids on the spot market for every hour, implying that prices and quantities in adjacent periods as well as the data on the shift variables are likely to be serially correlated. To yield valid statistical tests, the econometric model must be modified to account for this serial correlation.

4.2.1 Findings

4.2.1.1 Market power at the system level

Hjalmarsson (2000) is the first to apply the Bresnahan-Lau model to the Nordic power market. He estimates market power at the system level using weekly data from 1996 to 1999. Demand is assumed to be linear. Temperature and day length are the main shift and rotation variables of demand. The marginal cost function is assumed to be quadratic in output and linear in its shift variables–mainly current and lagged water inflow. Hjalmarsson finds that the hypothesis of perfect competition cannot be rejected.

Vassilopoulos (2003) and Bask et al. (2007) essentially replicate the study by Hjalmarsson (2000), but examine a longer time span, including the period when Finland and Denmark joined Nord Pool. Vassilopoulos cannot reject the hypothesis that the Nordic power market was perfectly competitive during the period 1997 to 2003. Bask et al. analyse the period 1996 to 2004 and find, contrary to Hjalmarsson and Vassilopoulos, statistically significant mark-ups. The estimated mark-ups were economically small, however, in the order of 1% over the entire period. Furthermore, the statistical significance of the mark-ups vanishes towards the end of the studied period, suggesting that the enlargement of the Nordic power market to Finland and Denmark increased competition and eliminated any previous market power.

4.2.1.2 Market power and transmission constraints

The fourth study to apply the Bresnahan-Lau model to the Nordic power market is Steen (2004). He limits the geographical scope to southern Norway, but uses a more detailed data set than the studies discussed above. Steen has hourly data, enabling him to estimate local market power arising from temporary bottlenecks. During the period under study, from January 2001 to October 2002, southern Norway was a high price bottleneck area during 12.7 % of all hours. In line with the previously discussed studies, Steen cannot reject the hypothesis of perfect competition when electricity flows are unconstrained. By contrast, his estimates for the bottleneck periods suggest a statistically significant, yet economically small markup; the estimated Lerner index is 1%. Steen argues that this evidence suggests that mergers and acquisitions should be viewed with caution, as they lead to increased market concentration. In fact, transmission constraints were raised as a concern when Statkraft was allowed to acquire one of its smaller competitors, Agder Energi; see Skaar and Sørgard (2006) and references therein for a summary of the debate.

An alternative model: Johnsen et al. (2004) develop an alternative empirical model for estimating whether bottlenecks lead to market power. This model has minimal data requirements; neither production data nor marginal cost data are required. Rather, it infers changes in market power by exploiting how prices differ across periods with more or less elastic demand and across areas with and without bottlenecks.

Specifically, Johnsen et al. assume demand to be more elastic during the day than at night[10], implying a larger scope for market power at night. In addition, they assume that non-congested price areas can be used as controls for congested areas. For this approach to be valid, the control areas must be sufficiently similar to the congested ones in terms of production mix and marginal costs. If so, observed differences in prices between a treatment and control area and across periods with different demand elasticities should capture the extent firms' market power increases due to transmission constraints in low elasticity periods, i.e., at night.

Johnsen et al. have hourly price data for mainly 1998 in the five different Norwegian price areas: Bergen, Kristiansand, Oslo, Tromsø and Trondheim. Nightly transmission constraints are found to increase the firms' scope for market power in the Kristiansand region. Using either Oslo, Tromsø or the system price as controls, their estimates suggest that the increased market power stemming from transmission constraints increased nightly prices by 15%. In the other price areas, no such increases in market power were observed.

4.2.2 Evaluation

The main appeal of the above behavioural models is that they render possible an estimation of market power in the absence of marginal cost data. This is particularly appealing for electricity markets dominated by hydropower, as in the Nordic countries. The empiricist avoids the complicated task of estimating water values.

A weakness of behavioural models is the amount of structure required on the econometric model in order to quantify the effects. The empiricist must postulate specific functional forms on the demand and on the firms' cost structure, usually without prior knowledge about the correct functional form. An additional problem is that some firms may pursue other objectives than profit maximization, which would break the link between the observed variables and the postulated behaviour.

All the studies applying the Bresnahan-Lau model to the Nordic electricity market assume that the demand is linear in the price of electricity. This specification for demand is probably only a rough approximation of the true functional form for the demand of electricity. Nevertheless, all studies find the (short-term) estimated demand for electricity to be inelastic. This is reasonable, since only few large consumers can adapt their electricity consumption in the very short run. The demand estimates thus suggest that the linear specification is satisfactory.

The predominance of hydropower in the Nordic countries renders more difficult the determination of an appropriate functional form for the firms' marginal cost. In electricity markets dominated by thermal production, estimates based on engineering data suggest that the industry marginal cost is increasing and convex (Borenstein et al., 2002; Wolfram, 1999).

[10] This assumption is natural. Large energy intensive industries consume less electricity at night. It is mainly these consumers who can adapt their demand for electricity to short-run changes in electricity prices.

Thus a quadratic specification for the marginal cost appears motivated for thermal markets. Hjalmarsson (2000) argues that a quadratic specification is also reasonable for the Nordic power market: marginal costs should be constant and low at low output levels due to hydro and nuclear production and increase at higher output levels when thermal production is introduced. Yet, only the monetary cost of hydro production is low (near 0). The relevant cost–the opportunity cost of water as measured by the water value–may well be large in periods of scarcity and vary substantially over the course of a year. Therefore, it is far from obvious that marginal costs can be approximated by a quadratic cost function.

Some evidence (e.g. Wolfram, 1999) suggests that estimates of market power in electricity markets are sensitive to the specification of marginal cost functions. In a study of the California electricity market, Kim and Knittel (2006) find the indirect marginal cost estimates from behavioural models to be significantly lower than the direct measures of marginal costs. This suggests that behavioural models overestimate the degree of market power. Their study also suggests that the strength of the bias depends on the model specification.[11]

It is also unclear to what extent a static framework such as the Bresnahan-Lau model can capture market power in electricity markets dominated by hydropower. One reason is that observations distant from each other may be correlated due to the inter-temporal links of water values. The dynamic versions of the Bresnahan-Lau model applied to the Nordic power market are not designed to correct for inter-temporal decisions, but rather to account for short-run serial correlation due to, for example, demand persistence. In fact, these models presume that the firms solve a static problem at every point in time.

Probably due to the difficult task of estimating water values in the Nordic power market, there have been no attempts at comparing estimates of marginal costs between behavioural and direct models. In principle, such a study is feasible. Direct measures of marginal costs could be obtained by combining the estimated water values from simulation models with engineering data on costs for thermal and nuclear production. The water value estimates are not necessarily accurate, and so the merits and limitations of the behavioural studies on the Nordic power market cannot be evaluated solely on the basis of such a study. Nevertheless, a comparison of direct and indirect measures of marginal costs could be a useful robustness check against which to evaluate both approaches–simulations and behavioural models.

Finally, other behavioural approaches besides the Bresnahan-Lau model could potentially be used to study the Nordic power market. Kim and Knittel (2006), for example, study market power in the Californian electricity market using a model with a limited number of strategic firms facing a competitive fringe. Wolak (2003) uses a supply function equilibrium model specifying the equilibrium bid curves submitted by each firm. The Wolak approach is general in the sense that it does not require the specification of particular functional forms for supply and demand. A drawback of the two approaches is that they require more detailed data than the Bresnahan-Lau model. Wolak's methodology is the most demanding as it requires the bid curves posted by each firm. The Kim and Knittel model is less demanding; the data on prices and quantities need only be disaggregated at the level of the competitive fringe and the strategic firms. A lack of firm level data may explain why only the Bresnahan-Lau model or the even less demanding methodology proposed by Johnsen et al. (2004) has been applied to

[11] Behavioural models have also been evaluated in markets besides electricity in which data on marginal costs are available. Genesove and Mullin (1998) find in a study on the sugar industry that behavioural methods tend to overestimate marginal costs and thereby underestimate market power. Clay and Troesken (2003) find the opposite result in their study of the whiskey market.

the Nordic power market. This suggests that more detailed data would be highly valuable in testing for market power in the Nordic market for wholesale electricity.

5 Unresolved issues

The standard measures of market power are based on the mark-up over marginal production costs. Whereas a wedge between price and marginal production cost may be taken as an indicator of market power, the opposite is not necessarily true. Mark-ups are unable to capture several aspects of market power that could be important for the Nordic market. First, price less marginal production cost is a short-term measure of market power. It does not take investment incentives into account. Second, it exclusively considers the seller side of the market, thereby ignoring the potential for exercising buyer power. Third, by focusing on the technologies producing on the margin, it may fail to detect market power in base-load technologies. Fourth, the marginal production cost may not necessarily be the relevant measure of marginal social cost when some technologies are associated with environmental costs. This section considers each of these issues in turn.

5.1 Capacity investments

In the short run, firms face a decision of how much to produce given their capacities. In the longer run, firms must decide how much to invest in capacity. Investment decisions are subject to the same trade-off as short-run production decisions. Additional capacity leads to higher profits through an output expansion, but the profitability of installed capacity goes down due to a resulting price drop.

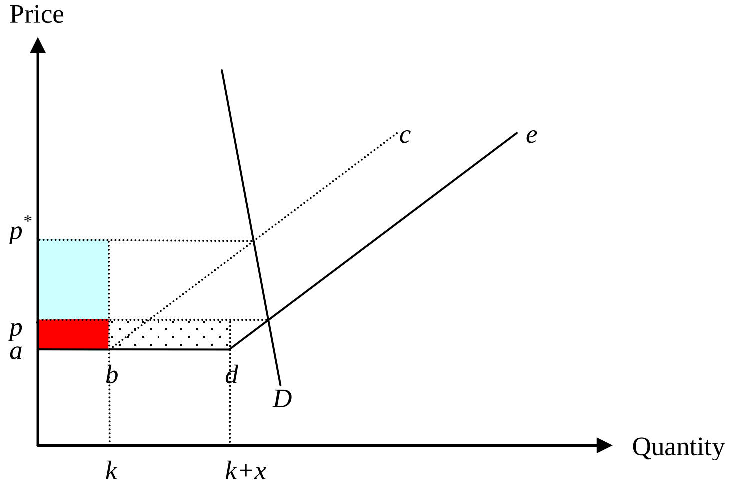

Figure 9: Long-run market power

Figure 9 illustrates this trade-off. Assume that short-run production is supplied competitively. Supply is given by the industry marginal cost curve, the line segment *abc*. It is constant up to the point *k* at which base-load is fully utilized and linearly increasing thereafter. Demand is given by *D*. The equilibrium price is *p**, and the profit (*p*-a*)*k* of base-load is given by the sum of the dark and light shaded areas in the figure. Consider the effects of an investment which expands base-load capacity by *x*. The new capacity is *k*+*x* and supply shifts out to the right to *abde*. The market now clears at the lower price *p*, and base-load profit, (*p*-*a*)(*k*+*x*), equals the sum of the dark shaded area and the dotted area. The investment affects more the price than demand. Therefore, the loss of profit due to the price reduction (the light shaded area) is higher than the profit due to capacity expansion (the dotted area) and so the investment is unprofitable to the incumbent.

In the figure above, price is always equal to marginal production cost for *any* capacity level since the market is competitive in the short run. Therefore, price-cost margins are unable to capture the exercise of long-run market power.

Normally, long-run market power is limited by the threat of entry. An entrant would not face the negative price effect on installed capacity (the light shaded area in Figure 9), but would only consider the profit associated with the capacity expansion (the dotted area in Figure 9). Entry would be profitable for any investment cost smaller than the dotted area. An incumbent might foresee this chain of events and choose to undertake the investment itself to deter entry.

Investments in new capacity by incumbents and entrants are surrounded by legal and political barriers. In addition, imports are bounded by limited transmission capacity. Both market power and exogenous investment barriers may thus lead to distorted investments in generation capacity. To gauge the significance of market power it would be necessary to separate the two effects. Political considerations will continue to play a dominant role in the near future, but perhaps less so as a barrier to investment. With the war on global warming sailing high on the political agenda, investments in renewable energy are highly encouraged. The prohibition in Sweden against investments in nuclear capacity may also be lifted. Over the next decade, planned investments in wind power and nuclear capacity in Sweden alone amount to nearly € 20 billion (Svensk Energi, 2008).

Finally, overinvestment can in theory be used to block entry. An incumbent firm which has invested in excess capacity can credibly commit to intense competition subsequent to entry. The fear of intense post-entry competition could be sufficient to deter entry (Dixit, 1980). Strategic overinvestment would manifest itself as idle production capacity and short-term market power.

5.2 Vertical integration and buyer power

The Nordic electricity wholesale market is characterized by vertical integration which leads to both buyer and producer concentration. In Sweden, the three major generation companies also stand for three quarters of the wholesale power purchased on the day-ahead market. If some of the generation companies are significant net buyers on the market instead of net sellers, the question of buyer power arises. Typically, one expects a strategic buyer to use its market power to reduce the prices of its purchases.

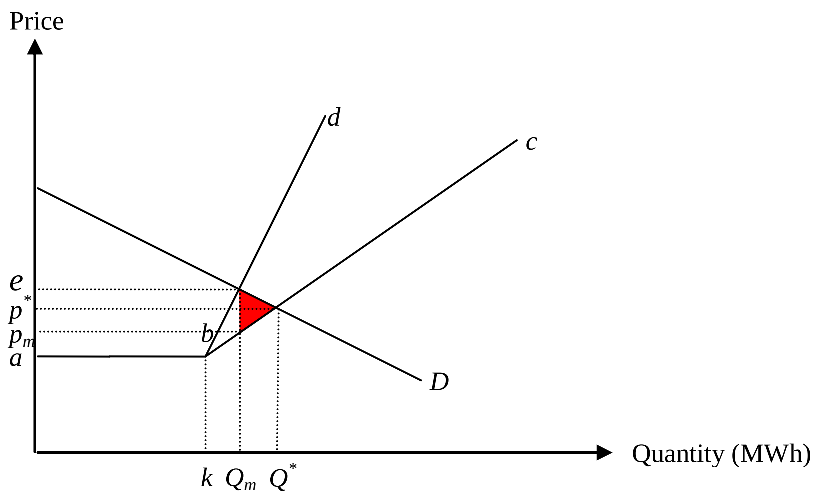

Figure 10: Buyer power

Figure 10 illustrates the incentives of a strategic buyer. We assume that power is supplied competitively and thus equals marginal production cost given by the line segment *abc*. The competitive buyer takes the price as given and continues to purchase until the price equals the willingness to pay, with the competitive equilibrium at price p^* and quantity Q^*.

The strategic buyer takes account of the upward effect on prices. Thus, the marginal purchase cost, *MUC*, exceeds the price. In Figure 10, *MUC* is identified by the line segment *abd*. A strategic firm continues to purchase until its marginal purchase cost equals its marginal valuation, at quantity Q_m and price p_m. Relative to perfect competition, buyer power leads to under-pricing by p^*-p_m and under-consumption by Q^*-Q_m. Producers are willing to supply at a price below the marginal valuation of the good for all quantities between Q^*-Q_m. The welfare loss of foregone production is the shaded area in Figure 10.

The conventional measure of seller market power–the difference between price and marginal production cost–cannot detect the presence of buyer power. In Figure 10, price always equals the marginal production cost. Instead, market power drives a wedge between the marginal valuation of the good and the wholesale price, $e-p_m$ in this case. Unfortunately, this marginal valuation cannot be observed directly. Using retail prices and customer bases as a basis for the marginal valuation is complicated because retail prices are likely to reflect both wholesale buyer power and retail seller power. The two effects must be separated.[12] Vertical integration may introduce additional strategic considerations related to the retail market. For example, a large generating company could gain a competitive advantage in the retail market by pushing up the wholesale price, thereby raising the costs of non-integrated rivals.

5.3 Market power in base-load production

Market power is often measured as the difference between the wholesale price and the marginal cost of the most expensive active production unit. However, producers may also have an incentive to exercise market power in non-marginal units. Assume a competitive supply of non-base-load production, as in Figure 11.

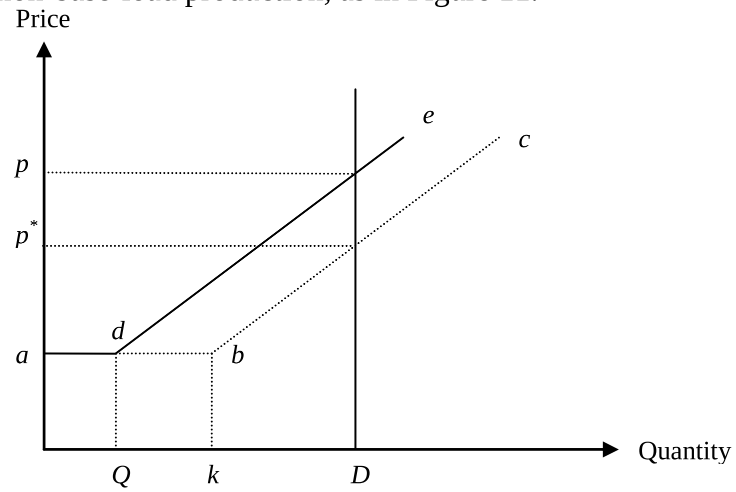

Figure 11: The effect of reducing base-load capacity

Industry marginal production cost equals the line segment *adbc*, being constant up to the point *k* at which base-load capacity, e.g., nuclear production, is fully utilized and linearly increasing

[12] Bushnell et al. (2008) show in a study of the liberalized US markets that integration between wholesale and retail significantly impacts market outcomes. During their sample period, retail prices were essentially regulated. Hendricks and McAfee (2008) derive appropriate concentration measures for vertically integrated industries with both seller and buyer power.

thereafter. Demand is inelastic and equal to *D*. A reduction in base-load production from full capacity *k* to *Q*, implies a leftward shift in the supply curve, to *ade*. The equilibrium price increases from p^* to *p* as cheap base-load production is replaced by more expensive technologies. Market power has been exercised, but will not turn up in conventional measures, as price still equals the marginal cost of the most expensive unit.

Reliable plant capacity numbers are crucial to the estimation of market power. Unfortunately, it may be difficult to disentangle unplanned or prolonged maintenance stops from strategic withholding of production. This is particularly relevant to nuclear plants. For example, it is hard to see how a competition authority could argue that managers of nuclear power plants devote too much time to maintenance and security. It should also be noted that exercising market power through prolonged maintenance stops of base-load capacity may well be more profitable in a hydro-based wholesale electricity market than in a market dominated by thermal production. In a hydro-based market, the loss in base-load capacity can be replaced by an increase in hydro production. By reallocating water, the production loss can *de facto* be reallocated to periods of peak demand. In effect, prolonged maintenance stops of nuclear power plants may be viewed as a masked (and more profitable) way of spilling water.

Ownership structure might affect base-load market power. Presumably, the scope for market power is larger if base-load production is jointly owned by several generation companies, as a larger fraction of the price effects then is internalized. All three Swedish nuclear power plants are jointly owned by two or more of the large generation companies.[13] By contrast, base-load market power is probably less of a problem if base-load capacity is jointly owned by generation companies and industrial consumers, as in Finland. Consumers would have less interest in pushing up the wholesale price of electricity. Based on these two observations, one might expect less exploitation of base-load market power in Finland than in Sweden.

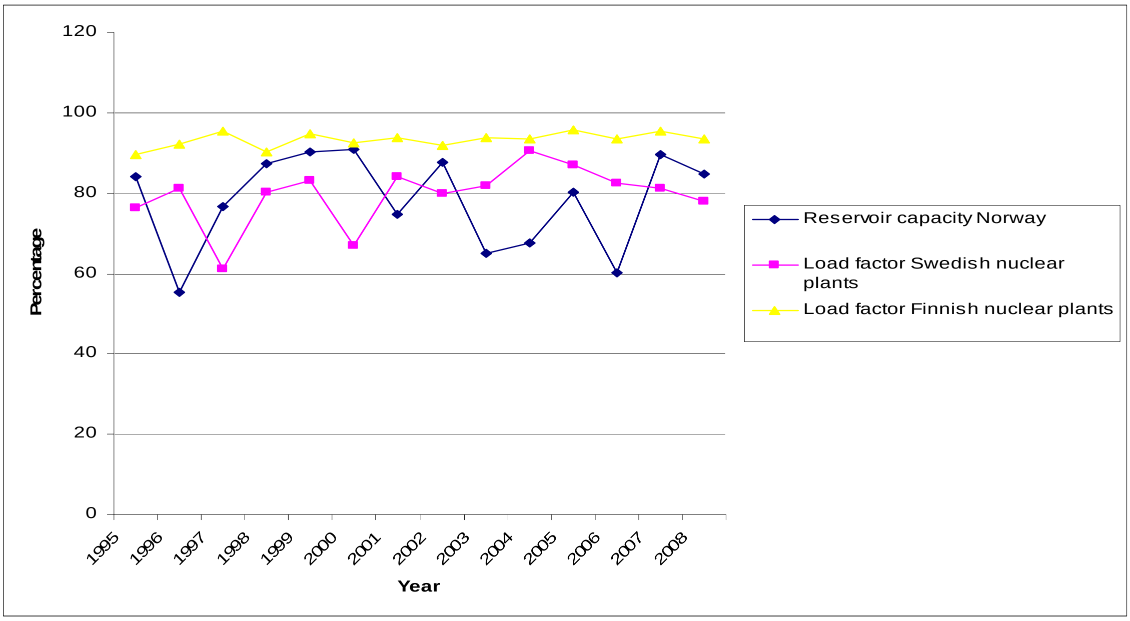

Figure 12: Load factors Swedish vs. Finnish nuclear power plants, 1995-2008

[13] The three plants are Forsmark, Ringhals and Oskarshamn. Vattenfall owns 66% of Forsmark and 70% of Ringhals. Fortum owns 22% of Forsmark and 43% of Oskarshamn, whereas E.ON owns 10% of Forsmark, 30% of Ringhals and 55% of Oskarshamn (Konkurrensverket, 2007). Vattenfall, E.ON and Fortum own roughly 50%, 30% and 20% of nameplate Swedish nuclear capacity.

As Figure 12 shows, capacity utilization (load factor) has been consistently lower in Swedish than Finnish nuclear plants over the past years, and production displays much more annual fluctuations in Sweden than Finland.[14] The question is whether this is a sign of market power.

Sweden relies more on hydro power than Finland because of a higher hydro capacity and more transmission lines to the hydro-dominated Norway. Nuclear production is less needed in a wet than a dry year and should thus fluctuate more in Sweden than in Finland even in a competitive market. Figure 12 also displays late summer (week 30) Norwegian reservoir capacity. Indeed, there is a negative relation between reservoir levels and Swedish nuclear production (the correlation coefficient is -0.3), but the relation is statistically insignificant (the t-statistic is -1.0). At first sight, these observations are consistent with competition, although a deeper analysis is required before one can draw general conclusions about the competitiveness of nuclear power production.

5.4 Environmental issues

Carbon emission taxes and the introduction of the market for emission rights in 2006 have driven up the cost of fossil fuel energy in Europe. Increased emission costs have had an effect on electricity prices in the Nordic countries, despite that the bulk of electricity is produced by means of hydro and nuclear power. In Nord Pool, all electricity within one price area is sold at the same price. The marginal production cost of the most expensive active production unit is a critical determinant of the price. These marginal production units are often fossil fuel plants. Therefore, emission costs even feed into the comparatively low-polluting Nordic power market. To the extent emission prices reflect pollution costs, marginal production cost estimates understated the marginal social production costs in the Nordic market prior to 2006 when the market for emission rights was introduced. This understatement has consequences for estimated welfare effects of market power. A rigorous welfare analysis of electricity markets should appropriately account for pollution costs.

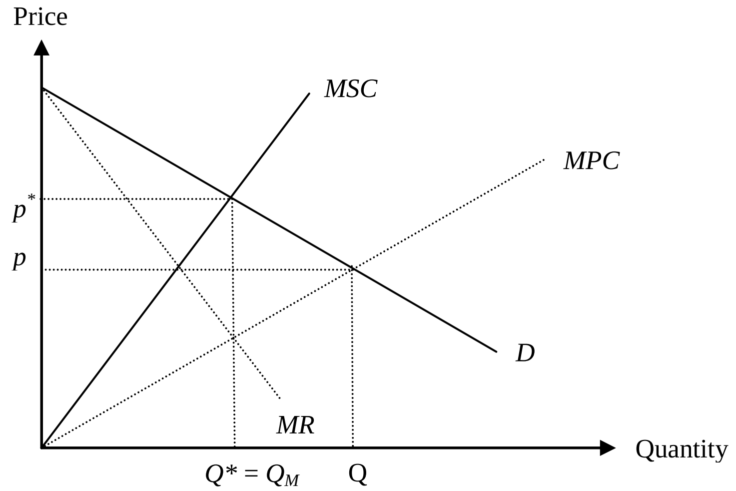

Figure 13: Market power and environmental policies are substitutes

One of the reasons for imposing emission costs is to bring down the consumption of energy. One of the consequences of market power is a consumption reduction. Market power is a substitute for environmental policies; it benefits the environment if it reduces over-consumption. Figure 13 illustrates this effect. Demand equals *D*. Socially optimal

[14] Plant utilization numbers are from IAEA's PRIS database. Reservoir level data are from Noregs Vassdrags- og Energidirektorats (NVE) website http://www.nve.no/ and from Statistics Norway (2000).

consumption is where the market clearing price p^* equals the marginal social cost, *MSC*. In the competitive equilibrium, the market clears at marginal production cost, *MPC*. The price p of electricity is too low: there is over-consumption by Q- Q^*. Under imperfect competition, the market is at equilibrium where marginal revenue, *MR*, equals marginal production cost, *MPC*. Marginal revenue is lower than the price, so the market clears below the competitive solution, at Q_M. In this (very special) case the imperfectly competitive equilibrium achieves the social optimum, i.e., $Q_M = Q^*$.

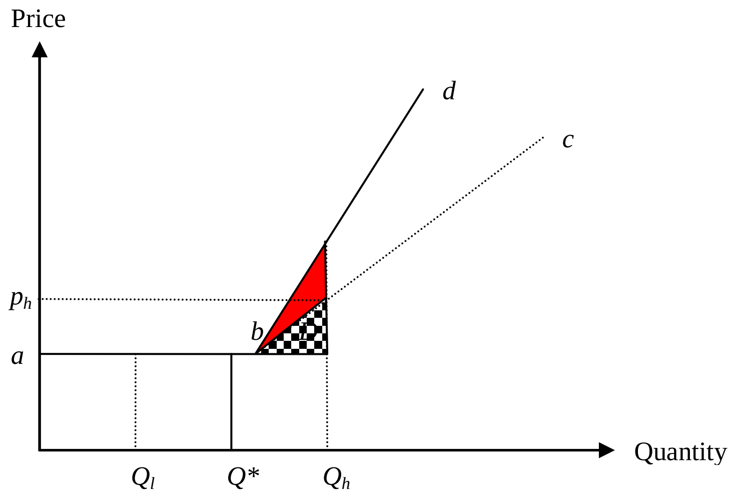

Figure 14: The environmental cost of market power in a hydro-thermal system

The consumption allocation effect above is an intermediary or long-term effect. For households, for example, electricity consumption is independent of short-term variations in the price. In this case, the problem of market power is more one of production misallocation. This tends to be exacerbated by pollution; see Figure 14. The marginal thermal production cost is given by the line segment *abc*, whereas the marginal social cost is higher and at *abd* due to pollution by fossil fuel burners. Assume for simplicity that there are two periods, one with high and one with low demand, and that thermal production is competitive. Socially optimal hydro production equates the marginal thermal production costs across periods. Here, thermal production is Q^* in each period and demand fluctuations are entirely covered by hydro. Note that this production plan leads even to full equalization of social production costs here. Assume now that a producer exercises market power by reallocating hydro production from high to low demand so as to take advantage of a higher price p_h in the high period. Some of the peak production is covered by fossil fuel production. The estimated welfare loss of market power is the chequered area. In reality, the welfare cost is higher due to pollution, the additional loss being the shaded area in the figure. If the marginal social cost of pollution increases in production, standard welfare analysis will underestimate the welfare costs of production misallocations in a market in which emissions are under-priced.

6 Concluding remarks

The empirical studies reviewed in this report produce no evidence of blatant and systematic exploitation of market power on the Nordic power exchange, Nord Pool. On average, the system price deviates only marginally from the competitive benchmark, and it is far from obvious that the source of the recorded differences is the exercise of market power. Consequently, there is no obvious rationale for intervention in the Nordic electricity market, neither by means of price regulations nor alterations in the market design, such as a regime shift from uniform to pay-as-bid auctions.

Some evidence suggests that the generation companies sometimes take advantage of capacity constraints in transmission to wield regional market power. One might expect the problem of regional market power to worsen if transmission constraints become more important in the future. Ideally, cost benefit analyses of transmission investments should take any pro-competitive effects on regional competition into account. Moreover, there is reason to examine the effects on competition of the requirement that all international transmission lines be at least 50 per cent state-owned, which reduces private transmission investments in the Nordic market.

It is time to look for market power elsewhere than short-run manipulations of marginal production. We believe it would be particularly fruitful to test for long-run market power as manifested by the incentives for investing in generation capacity. To successfully examine long-run market power and topics such as the exercise of buyer power and withholding of nuclear capacity, it is important to have access to better price, production and financial data. We propose that Nord Pool follows suit with other European electricity markets and release data on the individual behaviour of firms on the power exchange.

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