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Market Power in the Nordic Wholesale Electricity Market: A Survey of the Empirical Evidence

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

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Abstract
We review the recent empirical research concerning market power on the Nordic wholesale market for electricity, Nord Pool. There is no evidence of blatant and systematic exploitation of system level market power on Nord Pool. However, generation companies seem from time to time able to take advantage of capacity constraints in transmission to wield regional market power. Market power can manifest itself in a number of ways which have so far escaped empirical scrutiny. We discuss investment incentives, vertical integration and buyer power, as well as withholding of base-load (nuclear) capacity.

JEL codes: L13, L94, Q41

Keywords: Electricity markets; deregulation; market power; hydro power; transmission constraints

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1 Introduction and summary

As one of the first countries in the world, Norway established a trading system for wholesale electricity in 1991 as part of liberalizing the electricity sector. Sweden, Finland and Denmark have subsequently joined and created what was the first international power exchange in the world, *Nord Pool*. Despite its apparent success in attracting new member countries, there has been some concern as to how well the market actually functions.[1] Do the large generation companies exploit market power, thereby harvesting excessive profits? Or do the prices just reflect fuel prices, emission costs and energy taxes?

Given 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.

The Nordic wholesale market for electricity The bulk of wholesale power in the Nordic market now is bought and sold on the power exchange, Nord Pool. In Nord Pool, bid and ask curves are summed up to generate an hourly equilibrium price, the *system price*, where supply equals demand. Sometimes bottlenecks in transmission prevent full price equalization. When this happens, the Nordic market is divided into regional price zones. The Nordic market relies heavily on hydro power for its supply. In a normal year, hydro power stands for half the Nordic electricity production. Hydro power markets function differently from other power markets. In a hydro power plant, the production decision facing management is 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, for example, the less the power plant is able to produce when the winter comes. In a hydro based power market, output and prices are linked across time - they are *inter-temporal*. Any proper evaluation of the hydro market must take account of this dynamic aspect. In electricity markets that rely mainly on thermal supply, production decisions have a much shorter time horizon. In thermal electricity markets, "snapshots" can generate useful information about market performance.

Market power and its consequences A firm exercises market power if it engages in strategic manipulation of its prices to raise its profits. A profit maximizing firm without market power will continue to increase its production until (*i*) it fully utilizes its capacity or (*ii*) the cost of producing an extra unit, the marginal production cost, equals the output price. A strategic producer will take into account the negative effect of a larger output on the price of its goods. In a typical market with imperfectly competitive production, the market clears at a price above the marginal production cost since the value of an extra unit is below the price of the good. Hydro power markets are different. In a competitive hydro market, profit maximizing producers *reallocate* production from low price to high price periods until (*i*) they hit the capacity ceiling in the high price period or (*ii*) the expected discounted prices are equalized across periods. A strategic hydro producer, on the other hand, will take into account the demand effects of reallocating production. The demand effects are weaker in periods when the demand is insensitive to price changes, that is, demand is *inelastic*. Consequently,

[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 the 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 (2008).

strategic hydro producers will profitably allocate production from periods with inelastic to periods with elastic demand. Consequently, electricity prices tend to be higher in low elasticity than high elasticity periods when hydro producers exercise market power.

Market power affects welfare in a number of ways. Typically, market power leads to under-consumption. Demand is given by the purchases of those whose valuation of the good exceeds the price they pay for it. With market power, the market clears at a price above the marginal production cost. Therefore, some consumers are excluded who value the good below the market price, but above the cost of supplying it. In a hydro power market, market power typically also leads to misallocation of production. Since prices do not equalize across periods, marginal production costs will not do so, either. Therefore, aggregate production costs will be too high. Finally, market power transfers wealth from consumers to producers since the consumers pay too much for their electricity. Redistribution constitutes a welfare loss to the extent consumer surplus is valued higher than firm profit.

How to estimate market power? A competitive firm produces at price equal to marginal production cost. Therefore, a standard measure of market power is the difference between price and marginal production cost. For a hydro producer, the marginal production cost is the alternative cost of future production, the *water value*. The corresponding measure of market power in a hydro market is the difference between the observed price and the water value.

The problem 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. However, 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.

There are two main strategies for quantifying market power, a direct and an indirect one. Both methods have been applied to the Nordic electricity market. The *direct method* first estimates marginal costs and then compares the estimates with the observed prices. In the Nordic market, simulation models have been built which allocate hydro production across periods to maximize aggregate social welfare. The benchmark production profile delivers simulated competitive water values. The differences between the wholesale prices and the simulated water values provide estimates of market power. The *indirect method*, also known as the *behavioural method*, uses the observed prices and quantities to estimate marginal costs and market power. The main advantage of this approach is that marginal costs need not be estimated. An obvious drawback is its essentially static approach. Market power is estimated separately across periods, a procedure which ignores the fundamental inter-temporal structure of hydro power markets.

What do the data tell us about market power in the Nordic market? The simulation models paint a consistent picture of the Nordic market regarding system level market power. Behaviour is qualitatively consistent with market power. Systematic overproduction pushes the price below the competitive level during late spring and summer. Prices tend to be above the competitive level in late autumn and winter due to insufficient reservoir capacity, although not consistently so. The quantitative effects are weak. Kauppi and Liski (2008) nonetheless conclude that the price fluctuations are sufficient to count as evidence of market power. Edin (2001 and 2006) comes to the opposite conclusion. Also Damsgaard et al. (2007) are skeptical. Their skepticism is based in part on the observation that, except for shorter periods, firm revenue would have been higher if output had instead been competitive. Thus, observed output seems not to maximize profit. The weak quantitative effects of system level market power found in the simulation studies are corroborated by the behavioural studies of the market. Of the three studies of system level market power, only one finds evidence of market power. Bask et al. (2007) report statistically significant mark-ups of around 1%. Interestingly, significant mark-ups could only be found prior to the inclusion of Finland and Denmark in Nord Pool. This suggests that the expansion of the Nordic market has led to full evaporation of system level market power.

Local market power arising from transmission constraints may be more of a problem than system level market power. Damsgaard et al. (2007), for example, attribute the 18% mark-up over competitive prices in Jutland in 2002-03 to market power. Steen (2004) finds small, but statistically significant mark-ups in a study of transmission constraints and market power in Southern Norway. Finally, Johnsen et al. (2004) report in a study of Norwegian electricity prices that nightly bottlenecks tend to boost prices by 15% compared to the benchmark.

Estimating the cost of market power is important as it is the welfare cost and not market power *per se* which should found the basis for public intervention. However, only one of the studies in our sample attempts to gauge the costs of market power. Kauppi and Liski (2008) estimate the welfare loss of system level market power, mainly stemming from inefficient production, to be roughly 7 per cent, or 600 million Euros, over the period 2000-05.

What conclusions can we draw from the analysis? There is no evidence of blatant and systematic abuse of market power in the Nordic wholesale market. Market power seems to be either local or the deviations from competitive pricing small. Consequently, there is no obvious rationale for intervention, either by means of price regulations or alterations in the market design, such as a regime shift from uniform to pay-as-bid auctions. To the extent that transmission constraints become more restrictive in the future, one might expect the problem of local market power to increase. Ideally, cost benefit analyses of transmission investments should take the pro-competitive effects of investments on regional competition into account. Is the issue of market power settled, then? Not quite. However, the above results indicate that we should look elsewhere than to short run deviations from competitive prices for evidence of market power.

Uninvestigated sources of market power Market power can materialize in a number of ways that so far have escaped empirical scrutiny. In the long run, prices are determined by the extent to which capacity investments reflect demand growth. The firms' 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 the installed capacity goes down due to the resulting price reductions. Thus, long-run market power might lead to underinvestment among established producers. Entry might mitigate some of the expected underinvestment problems since entrants do not face the downside of reduced profitability on installed capacity. Historically, legal barriers to building new capacity and to relieving transmission bottlenecks have presented obstacles to investment, entry and imports. It remains an issue of future research to determine the extent to which market power or investment barriers affect investments.

The Nordic wholesale electricity market is characterized by buyer concentration through vertical integration in retail and generation. The Nordic market, therefore, holds the potential for the exercise of buyer power and vertical market power. These types of market power will not generally show up in the conventional measure of market power. Strategic considerations on both sides of the market would affect the marginal valuation of both electricity production and purchases which could create so far unknown inefficiencies in the Nordic market.

Generation companies may have an incentive to reduce nuclear power production to shift the supply curve to the left and drive up prices. Since nuclear power is cheap, the wedge between price and the marginal cost of the most expensive production unit, the standard measure of market power, cannot detect such base-load market power. Manipulation of nuclear production is particularly appealing as production stops aimed at manipulating the price can be difficult to separate from maintenance stops for an outside observer. Two features of the Nordic market might exacerbate the problem. In a hydro-nuclear market, withheld base-load production can *de facto* be targeted to the most profitable demand periods by a reallocation of water. Second, joint ownership of nuclear production across the generation companies implies that a larger fraction of the price effects is internalized by the market participants.

2 The Nordic electricity market

Historically, Nordic electricity supply was regulated along national borders. This changed dramatically in the 1990's when the Nordic countries gradually deregulated national generation and marketing of electricity. As one of the first countries in the world, Norway restructured its electricity sector in 1991. The remaining Nordic countries (except Island) subsequently deregulated their electricity sectors and integrated them into the common Nordic power market; Sweden joined in 1996, Finland in 1998 and Western and Eastern Denmark in 1999 and 2000, respectively.

2.1 Institutional details

Prior to deregulation, there was one large, state-owned utility in each country. 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 brought with it a number of changes. The monopoly franchises for the generation and sale of electricity were eliminated. Electricity should now be competitively supplied. Transmission and generation were separated. State-owned system operators were established in each country with the responsibility for managing the grid and balancing the supply and demand of electricity. Transmission and distribution remained regulated as network duplication was too costly to expose this part of the industry to competition. The national transmission system operators are Energinet (Denmark), Fingrid (Finland), Statnett (Norway) and Svenska Kraftnät (Sweden).

A non-mandatory power exchange, Nord Pool, was created to organize the trade of wholesale electricity. Nord Pool is owned by the different national transmission operators and consists of several markets. The cornerstone market in Nord Pool is *Elspot* which is a day-ahead market for physical delivery of electricity. The volume traded on Elspot as a share of total consumption has risen steadily from 25 per cent in 2000 to nearly 75 per cent in 2007 (Konkurrensverket 2008). Elspot is cleared on a daily basis in an auction where hourly supply and demand bids for the next day are aggregated and matched. This generates a market clearing price - the so-called system price. Provided that there are no transmission constraints, all electricity is traded at the system price. The institutional details for handling transmission constraints differ in the different countries. In Norway, the market is divided into different geographical areas with different market clearing prices in each area, so-called zonal pricing.

By contrast, in Sweden, prices are not allowed to differ in different regions and therefore bottlenecks are handled through counter purchases.

Nord Pool combines Elspot with a real time market, *Elbas*, and with a financial market, *Eltermin*. Elbas handles the final matching of demand and supply, balancing unexpected changes in demand and supply in the very short run. Eltermin handles standardized financial contracts such as futures, forwards and options to handle long run uncertainty. These contracts can be used to secure future supply of electricity at an agreed upon price and their time horizon can range from one day to up to three years. The system price determined in Elspot constitutes the reference price for the financial contracts traded in Eltermin.

In addition to the power exchange there are also bilateral agreements and trade over the counter markets which provide financial as well as physical contracts for delivery of electricity. These contracts are standardized or tailored to the needs of the parties involved.

2.2 Technologies

The total generation of electricity in the Nord Pool area was 397 terawatt-hours (TWh) in 2007. Table 1 displays production in 2007 across the four countries. A characterizing feature of the Nordic market is its reliance on hydro power. Half of the yearly generation is produced by hydro plants, located primarily in Norway and Sweden. The remaining electricity is supplied mainly by means of Swedish and Finnish nuclear power and by other sources of thermal power - mainly combined heat and power and condensing power - located in Finland, Denmark and to a lesser extent in Sweden. Finally, wind power is a growing but still small source of electricity generation and is primarily located in Denmark.

	Denmark	Finland	Norway	Sweden	Total
Hydro power	0	14	135	66	215
Nuclear power	0	22	0	64	86
Other Thermal power	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

A large number of sellers and buyers are active in the Nordic wholesale market. A few large players stand out, however. The three largest producers of electricity in the Nordic market, Vattenfall in Sweden, Fortum in Finland and Statkraft in Norway all date back to the era of regulation. In addition, two major companies, Elsam in Western and Energi E2 in Eastern Denmark, have formed through mergers and acquisitions. 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%. However, national market concentration is much higher. Transmission constraints may therefore have important anticompetitive effects.

A second important feature of the Nordic power market is vertical integration. Most generation companies are present also as buyers on the wholesale market.

3 Market power and its consequences

A firm is said to exercise market power if it engages in strategic manipulation of its prices to raise its profit. Market power is exercised in many forms besides direct price manipulations:

quantity adjustments, entry deterrence and capacity investments, to name a few. There are many sources of market power. The European Commission (2007) lists market concentration, vertical integration and market segmentation as the main obstacles to an internal market. [3]

As firms cannot be expected to admit to price manipulations, it is necessary to have a benchmark against which to test observed behaviour. A profit maximizing seller without market power will continue to increase its production until (*i*) it fully utilizes its capacity or (*ii*) the cost of producing an extra unit - the marginal production cost - equals the output price.

Competitive pricing, therefore, implies an output price equal to the marginal production cost and an input price equal to the marginal valuation of the input. We illustrate the producer's incentives in Figure 1:

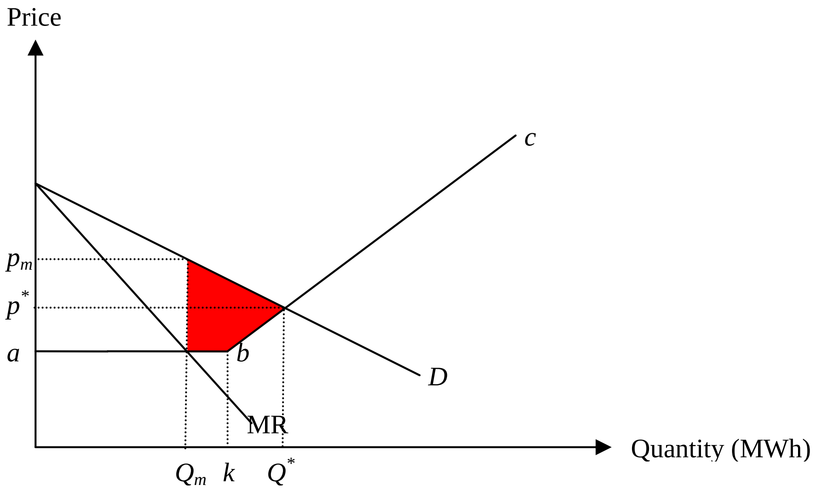


Figure 1: Market power in generation

A producer has capacity k of base-load electricity, say nuclear power. Base-load is produced with constant marginal cost a. The firm's marginal production cost *MPC* is increasing thereafter, which reflects the use of increasingly costly fossil fuel technologies. Consequently, *MPC* is given by the line segment *abc*. The demand facing the producer is decreasing in the price, i.e., it is *elastic*, and given by the line *D*.

A competitive producer takes the price as given and continues to produce until price equals marginal production cost. The competitive equilibrium is at the price p^* and quantity Q^*.

A strategic producer acknowledges that higher production implies lower prices. The marginal value of production, therefore, is below the price and given by the line *MR* (marginal revenue) in Figure 1. The imperfectly competitive solution is to produce until marginal revenue is equal to marginal production cost, at the price p_m and quantity Q_m in Figure 1.

[3] Some claim that power markets are particularly vulnerable to market power since electricity cannot be stored. This claim is questionable for at least three reasons. First, electricity *is* 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 excessively susceptible to the abuse of market power. Standard models of imperfect competition (e.g. Cournot or Bertrand) are in non-storable goods. The intensity of competition in these models depends on the number of firms, the price sensitivity of demand, switching costs etc, not on non-storability as such. Third, storable good markets are not necessarily particularly competitive. Dixit (1980) shows how an incumbent can soften competition by investing in capacity. By holding a large capacity or inventory, the incumbent can credibly commit to competing intensely following entry. This can be sufficient to block entry altogether, causing market imperfections.

Market power on the producer side leads to over-pricing by p_m-p^* and under-consumption by Q^*-Q_m. Market power can thus be measured as a deviation either from competitive prices or from competitive sales. The most common measures of market power are based on the equilibrium mark-up p_m-a.

Market power implies that too many consumers are excluded from buying the product. The associated welfare loss is the difference between the price consumers are willing to pay and the cost of producing it, the shaded area in Figure 1. The mark-up, p_m-a, provides little information about the welfare loss of market power. For example, market power is less costly the more expensive is fossil fuel production, i.e., the steeper is the line segment *bc*. However, this effect has no bearing on p_m- a. Thus, one cannot draw any conclusions as to the cost of imperfect competition based solely on the observation that firms take advantage of market power and the observed mark-up on their product.

Market power in a hydro-thermal system In a hydro-thermal system, production is limited by the reservoir capacity. To expand production in one period, it is necessary to contract production in other periods. Consequently, production decisions are linked across periods, they are *inter-temporal*. We illustrate this problem in Figure 2:

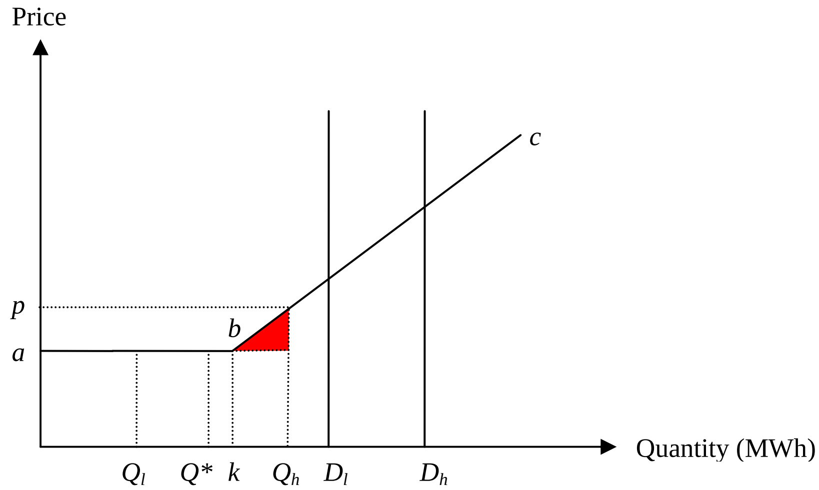


Figure 2: Market power in a hydro-thermal system

Assume that thermal power is competitively supplied. It is given by base-load supply, e.g., nuclear power, up to capacity *k*. Base-load marginal cost is constant and equal to *a*. The marginal thermal production cost *MPC* is increasing thereafter, as increasingly costly fossil fuel technologies are activated. Consequently, *MPC* is given by the line segment *abc*. 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 (inelastic) in both periods, with peak and off-peak demand given by D_h and D_l, respectively. Suppose thermal production is Q_h in the high demand period, but only Q_l in the low period. Residual demand is covered by hydro production, D_h-Q_h and D_l-Q_l in the high and low period, respectively. The peak price is higher than the off-peak price, *p* versus *a*, in this case owing to the activation of costly peak fossil fuel production.

Assume that even hydro is competitively supplied, i.e., hydro producers are price takers. Each producer must decide how much hydro power to allocate to each period. Since the peak price is higher than the off-peak price, it is profitable to transfer hydro production from the low demand period to the high demand period. This reallocation takes place until the prices in both periods are equalized, which in Figure 2 occurs at thermal production Q^* and price a. We can draw two conclusions about competitive hydro markets. Absent capacity constraints, water balances fluctuations in demand which implies 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, as can be seen directly from Figure 2. At the competitive solution Q^*, hydro power is sold at a in both periods. By reallocating hydro from peak to off-peak, hydro producers are able raise the peak price of electricity to p and thereby sell the total quantity of hydro power at an average price above a.

Market power is reflected in deviations from full price equalization. In principle, price fluctuations can be viewed as evidence of market power. In reality, prices fluctuate also as a result of capacity constraints and unexpected events, such as water inflow and demand shocks. Thus, it is necessary to consider alternative measures. In the Nordic market, reservoirs are filled during the summer and autumn and emptied during the winter and spring. Over-production in the low summer season means that the producer tends to enter the winter season with too low reservoir levels. One way to test for hydro market power in the Nordic market, therefore, would be to compare actual reservoir levels with competitive ones .

Price and marginal cost equalization leads to cost minimization of thermal production across periods in 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 2. Q_h-k MWhs of electricity are unnecessarily 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 which is produced inefficiently.

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

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

4 Estimation methods

There are two methods for estimating market power. The *direct method* estimates marginal production cost based on industry data and compares the estimate to observed market prices. Systematic deviations are taken as a sign of market power. *Indirect methods* start out from 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. Models that fall into the second category are sometimes referred to as *behavioural* *models* (Twomey et al. 2005)[4]. Both direct and indirect methods have been used to test for market power in the Nordic spot market. We consider each in turn.

4.1 Direct estimation

Engineering data can be used to generate reliable cost estimates for thermal production. Fuel costs comprise 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 with fuel prices allows reliable estimation of the fuel cost component. Consequently, industry marginal cost functions are readily available for electricity markets that rely primarily on nuclear and fossil fuel technologies.[5]

A significant portion of the electricity supplied to the Nordic market is from hydro generation facilities with water reservoirs. The cost of producing hydro power is essentially its alternative cost: water that is poured out of the reservoir today cannot be used for production tomorrow. In order to create a competitive benchmark, one has to simulate the market and incorporate the inter-temporal aspects of hydro power. Typically, water is allocated across periods by means of a stochastic dynamic programming procedure so as to maximise the expected social welfare over the period, taking the expected demand for electricity and the uncertain inflow of water into account. Given the benchmark production, one can compute a competitive marginal cost of water, the so-called *water value*. Water is sold competitively if the observed spot price is equal to the computed water value.

The analysis of hydro power is complicated by the fact that the alternative cost of water usage varies across hydroelectric power plants. A plant with a large reservoir and a comparatively small turbine capacity can run at full capacity for a long time without significantly affecting its future production possibilities. This plant displays a low alternative cost of water usage and therefore a low water value. 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 climate and geographical conditions. 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 computationally impossible to handle. The simulation models differ in the level of detail with which they model reservoir and turbine capacity.

Congestion in the transmission lines imply that the Nordic market sometimes is divided into regional pricing areas. Bottlenecks imply that regional demand net of regional imports can be served by local producers only. Local opportunities for exercising market power then arise as a consequence of bottlenecks. Ideally, one would like to treat every price region separately, accounting explicitly for interregional transmission capacity. The simulation models vary in how they account for capacity constraints in transmission.

[4] There is a third category, known as *structural* models (Twomey et al. 2005). The main approach here is to construct indexes of structural variables, such as market concentration, thought to be related to market power. Structural models 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 Twomey et al. (2005), Ilonen (2005) or Vassilopoulous (2003) for detailed descriptions of the approach. See also Energimyndigheten (2006) for an application of the approach to the Nordic electricity market.

[5] Classical studies have used this direct estimation method to measure market power in the California electricity market (e.g., Joskow and Kahn 2001, Borenstein, Bushnell and Wolak 2002) 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 limited amount of market power in the UK.

4.1.1 Model descriptions

4.1.1.1 The KL model by Olli Kauppi and Matti Liski

Olli Kauppi and Matti Liski (2008) at Helsinki School of Economics construct a simulation model of the Nordic electricity market with the purpose to study market power in a storable goods industry. Hydro power is a storable good insofar the considered power plants have water reservoirs. We henceforth refer to this as the KL model.

The KL 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 equilibrium price that would prevail absent transmission constraints. Demand for electricity is random, but price independent. The KL 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 have the same technologies and inflows, but of different scales. The KL model focuses on hydro market power. Non-hydro supply is estimated on the basis of seasonal variation and the price of fossil fuels.

4.1.1.2 The BID model by Econ-Pöyry

The BID model is the property of the consulting company Econ-Pöyry, developed to analyse the profitability of generation and transmission investments. Subsequently, Econ-Pöyry has modified BID so as to incorporate market power issues (Damsgaard et al. 2007).

The BID model has an hourly resolution, in accordance with Nord Pool´s Elspot market, and can handle regional price zones. Consequently, transmission constraints are to some extent accounted for. BID includes start/stop costs for thermal power production. In the specification adapted to the analysis of market power, demand for electricity is random, but independent of the price. Hydro power is aggregated across regions, with an aggregate reservoir level and aggregate turbine capacity for each price region. BID accounts for regional plant variations by assuming a distribution of the water value around the regional mean. Engineering data have been used to estimate marginal cost curves for nuclear and fossil fuel plants.

4.1.1.3 The PoMo model by EME Analys

PoMo is proprietary to the consulting firm EME Analys. Its primary use is as a forecasting tool for electricity prices, but it has been used also to evaluate prices in relation to marginal costs in the Nordic market (Edin 2001 and 2006)

PoMo forecasts weekly system prices. Demand for electricity is random and independent of the price. 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 regional mean. Engineering data have been used to estimate marginal cost curves for nuclear and fossil fuel plants.

4.1.1.4 Additional models

There are a number of additional stochastic dynamic programming simulation models 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, has the most detailed modelling of hydro power in the Nordic market. 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. It is primarily used for spot price forecasting. EMPS has 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, 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, its development financed by the Danish Energy Research Program. Balmorel is able to simulate imperfect- as well as perfect competition.

4.1.2 Findings

Kauppi and Liski's (2008) finding is that hydro producers systematically over-produced during summers and under-produced during winters compared to the social optimum in the considered period 2000-05. This tended to create excessive price fluctuations; see Figure 3.

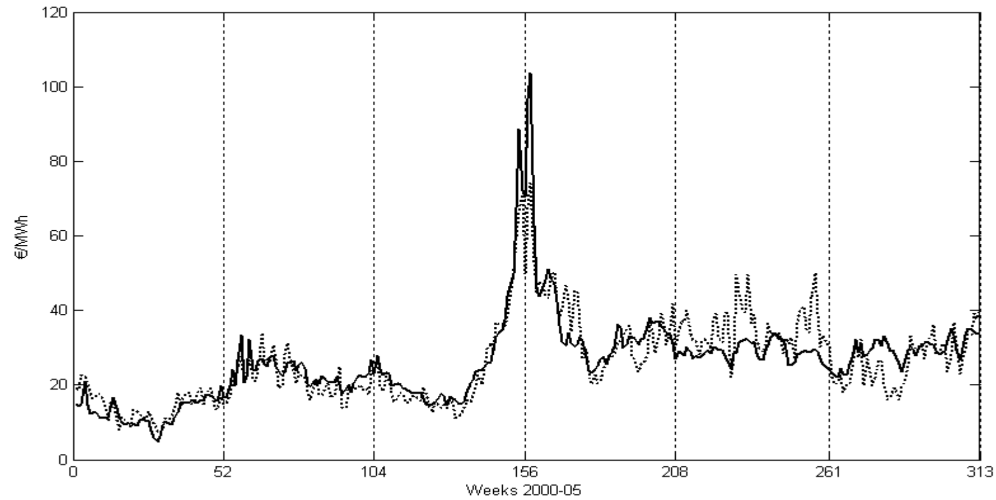


Figure 3: Observed (solid) vs. simulated (dashed) system price (Kauppi and Liski 2008)

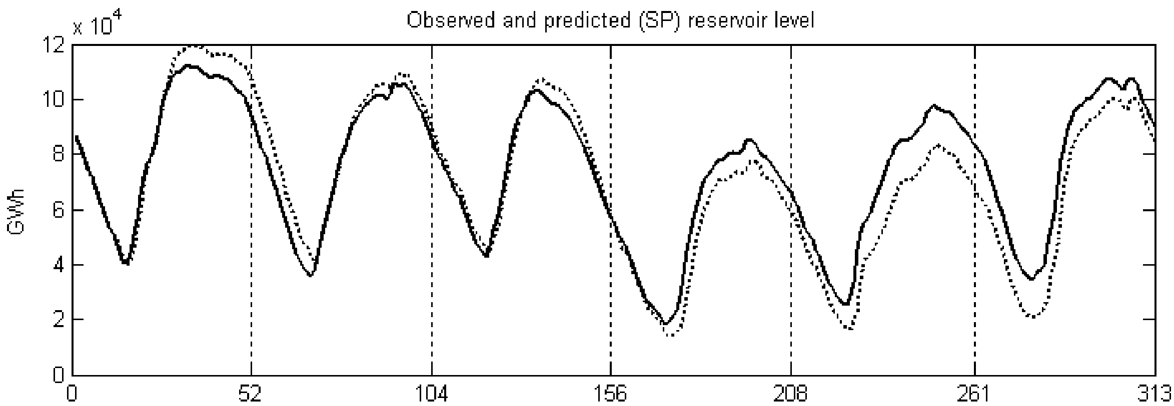


Figure 4: Observed (solid) vs. simulated (dashed) reservoirs (Kauppi and Liski 2008)

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 latter. From 2003 and onwards, reservoir levels on the contrary appear to have been too high.

The BID model was tested for two water shortage periods, summer to winter 2002-03 and summer to autumn 2006, and a normal period with normal reservoir levels, summer and autumn 2001 (Damsgaard et al. 2007). The results are reported in Table 2.

	Deviations from the modelled (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 2002-03 period are consistent with a market power scenario with overproduction and prices below the competitive level up until December, and 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, things 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 possibly could have contributed to the results. In the normal situation 2001 there were no signs of market power. Rather, production seems to have been consistently above the estimated competitive level.

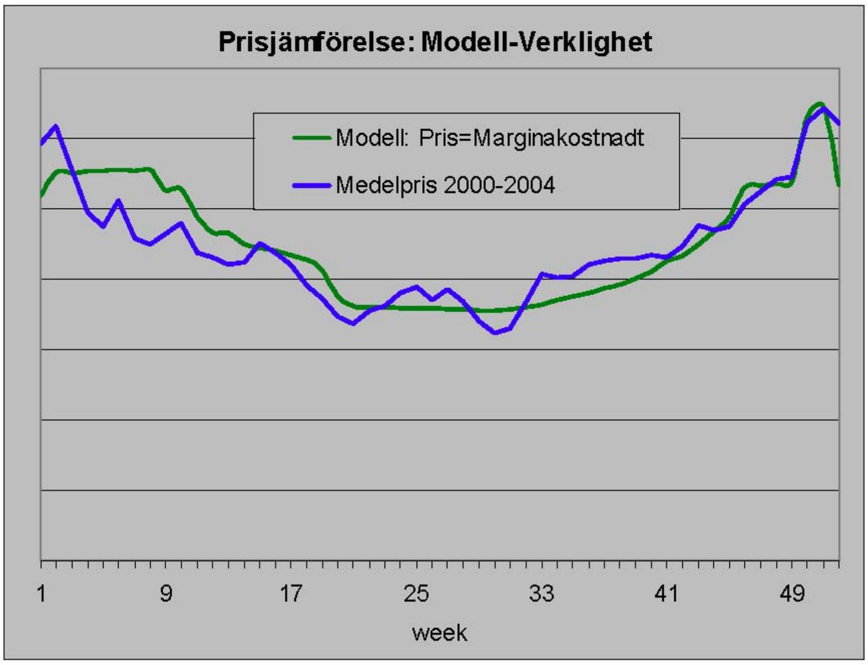


Figure 5: Price comparison average and estimated system price (Edin 2006)

The PoMo model has been simulated for the periods 1996-2001 (Edin 2001) and the period 2000-04 (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) views the estimated price differences sufficiently modest to render the Nordic power market competitive.

4.1.3 Evaluation

The three simulation models, KL, 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 2002-03. 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 insufficient 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 2000-05.

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, current industry marginal costs based on historical capacity utilization will lead to an overestimation of current marginal costs and, as a result, a downward bias in market power.

The KL model avoids the problem of estimating thermal capacity utilization by focusing entirely on market power in hydro production. Thermal supply rather than marginal costs is estimated. It follows that the KL model does not analyse industry market power, but rather market power for a subset of the production plants, namely hydro. This renders an estimation of the optimal hydro production more difficult. Welfare maximization implies 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. This effect is illustrated in Figure 6.

Here, thermal producers exercise market power when demand is high, but not in low demand periods. Off-peak thermal supply S_l, then, is equal to 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 is at a, it would be socially optimal to expand peak production from Q_h to Q^* and to reduce off-peak production from Q_l to Q^*. This would be 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. Consequently, the optimal reservoir levels are overstated.

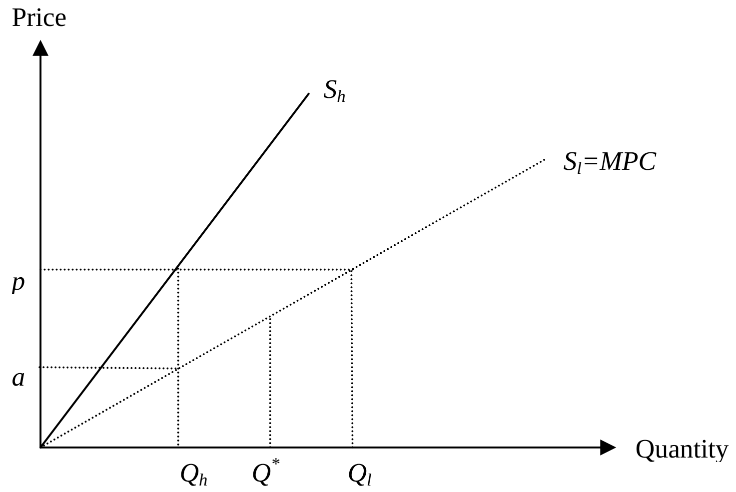


Figure 6: Price equalization with market power in thermal production

Most thermal production technologies incur start-up or shut-down costs, so-called ramping. With 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 transfers into an overestimation of peak market power and an underestimation of off-peak market power.[6] The BID model accounts to some extent for ramping costs, whereas PoMo ignores them. Ramping is less relevant in the KL model as this model does not consider thermal market power.

Transmission constraints sometimes 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 KL and PoMo models cannot capture local market power. Moreover, by neglecting transmission constraints welfare analyses will generally overestimate the cost of market power.[7]

The alternative 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 not as easy in reality as in the simulation models. *A priori* it is unclear how this affects socially optimal hydro production, but it would be a valuable robustness check to see how the simulation results depend on the aggregation.

4.2 Behavioural methods

Behavioural methods start out from observed prices and quantities and use statistical techniques to infer marginal costs and mark-ups given an assumed behavioural relation

[6] 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.

[7] 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.

between observed input variables, prices and quantities. The most widely used behavioural assumption is that of profit maximization. Additional structure is placed on the econometric model; normally in terms of specific functional forms regarding the demand for and the marginal cost of producing of electricity.

4.2.1 The Bresnahan-Lau model

There have been several applications of behavioural methods to the estimation of mark-ups in the Nordic power market. Most of these studies are based on Bresnahan (1982) and Lau's (1982) econometric model for identifying market power.[8] In its simplest form, the model is static, positing two relationships. One describes how the demand for electricity depends on the electricity price and on other observable demand shifting variables, such as temperature and day length. A common assumption is that demand depends linearly on the price and on the shift variables. The second relationship describes the supply of electricity: how the price charged by firms depends on their marginal cost and on an additional term reflecting that producers with market power set the quantity and price so as to equate their marginal cost with their marginal revenue rather than their price. Frequently, firms' marginal costs are assumed to depend linearly on the quantity supplied and on other variables shifting marginal costs, such as fuel prices and water inflows.

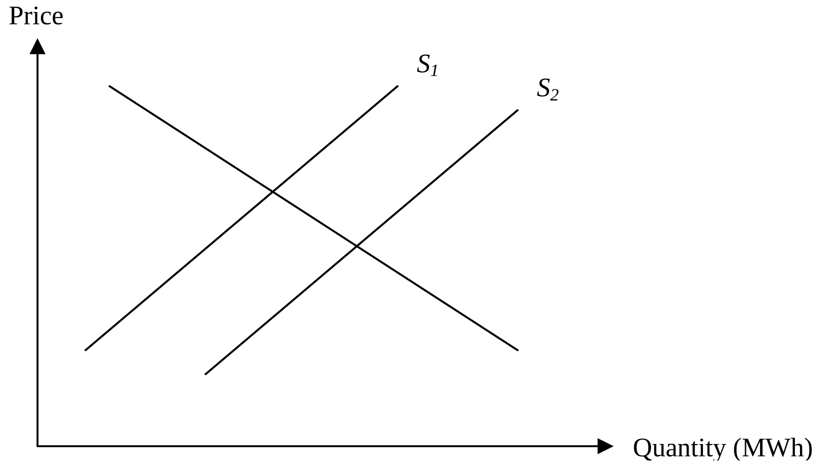


Figure 7: Estimating demand by means of supply variation

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 shift in for example the water inflow. As a result, we observe two price and quantity combinations which are used to trace out (and to estimate) the demand equation. Similarly, one may estimate the firms' supply schedule thanks to observable changes in the variables shifting only the demand equation.

To identify the firms' market power, that is, to separate the marginal cost component from the mark-up component in the supply relation, is more problematic. This is illustrated in Figure 8. Initial demand is low and described by D_1. The observed price/quantity combination is given by (p_1,q_1). This price/quantity pair is consistent both with a perfectly competitive market and with a monopolized market where the marginal cost equals marginal revenue. In the first case, marginal cost is high and given by MC_h. In the second, marginal cost is low and equal to MC_l. Now assume that demand shifts out to D_2, due to an (observable) reduction in temperature, for

[8] An exception is Johnsen et al. (2004). We discuss this study below.

example. As a result, we observe a new price and quantity pair (p_2,q_2). While this pair and the initial price/quantity pair are helpful to estimate supply, they have little to say about the firms' market power. This new price/quantity pair is as consistent with perfect competition (marginal cost is high) and monopoly (marginal cost is low) as was the initial price/quantity pair.

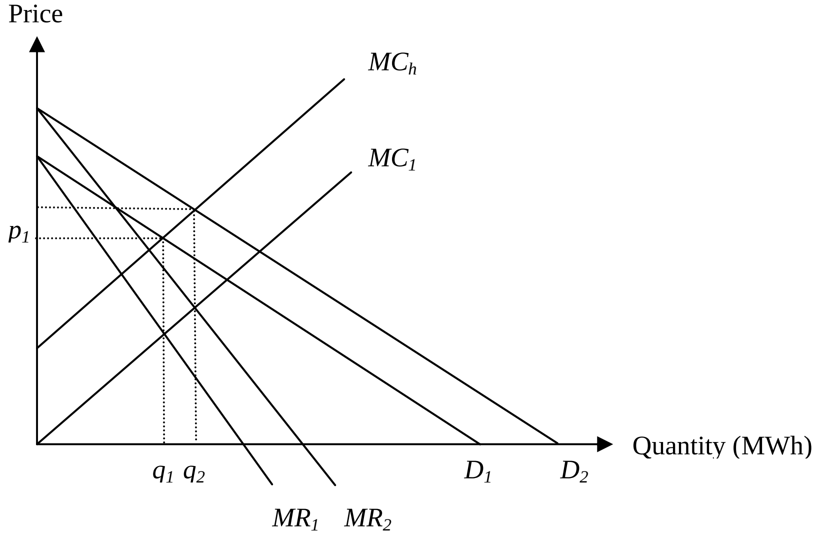


Figure 8: The problem of estimating market power

Bresnahan (1982) and Lau (1982) found conditions on the demand equation, allowing the marginal cost component to be isolated from the market power component in the supply equation. Market power can be identified provided the exogenous variables in the demand equation do not only shift but do also *rotate* the demand curve.

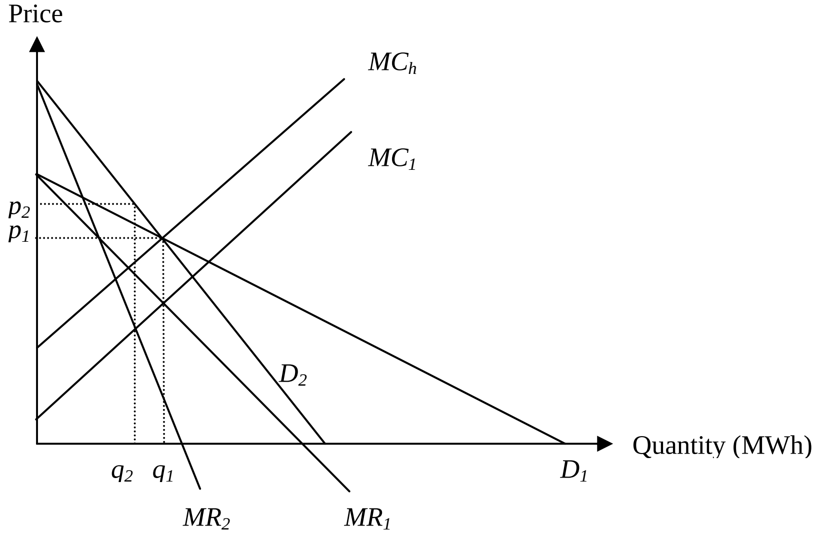


Figure 9: Using demand rotation to identify market power

An intuition for their result is provided in Figure 9. As in Figure 8, initial demand is D_1 with an observed price/quantity pair (p_1,q_1), consistent both with perfect competition (the marginal cost is high) and monopoly (the marginal cost is low). Consider an observable shock which rotates the demand curve around the initial price/quantity pair. 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 the low marginal cost) will reduce its quantity to q_2 in order to raise price to p_2. Since the firm's response to this shock depends on its market power, it turns out to be possible to identify the degree of market power.

In practice, the estimation of market power is done in two steps. First, the demand and the implied industry marginal revenue are estimated using shifts in the supply curve. With these estimates in hand, the next step is to estimate the marginal cost curve and the degree of market power using shifts and rotations in the previously estimated demand curve.

The four applications of the Bresnahan-Lau model to the Nordic power market use a dynamic extension of the model initially proposed by Steen and Salvanes (1999). The reason for using a dynamic model is that the 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. As a result, the econometric model must be modified in order to yield valid statistical tests which embed this serial correlation.

4.2.2 Findings

4.2.2.1 Market power at the system level

The first study applying the Bresnahan Lau model to the Nordic power market is Hjalmarsson (2000). He estimates market power at the system level using weekly data from 1996 to 1999, during which only Norway and Sweden had deregulated their markets. 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 estimates first the demand equation, using the marginal cost shifters as instruments for the system price. Then, he uses the estimated demand equation to distinguish the marginal cost from the market power component in the supply equation. His main finding is that the hypothesis of perfect competition cannot be rejected.

Vassilopoulos (2003) and Bask et al. (2007) essentially replicate the study by Hjalmarsson (2000), but for a longer time span, including also 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, that generators did enjoy a statistically significant market power. However, the estimated mark-ups were economically small; in the order of 1% over the whole period. Furthermore, the statistical significance of the mark-ups vanishes towards the end of the studied period, suggesting that the enlargement of the Nordic market power to Finland and Denmark increased competition and eliminated any market power.

4.2.2.2 Market power and transmission constraints

The fourth study applying the Bresnahan-Lau model to the Nordic power market is Steen (2004). He limits the geographical scope to Southern Norway, but uses a much more detailed data set than the studies discussed above. Steen has hourly (as opposed to weakly) data. This enables him to make a distinction between generators' market power during periods when the transmission grid is congested and when it is not.[9] This is important for two reasons. First, bottlenecks presumably increase the scope for market power by protecting local generators

[9] Steen's study differs also from the other studies in several other respects. For example, he assumes that the marginal cost is linear rather than quadratic.

from competition in the congested area. Second, bottlenecks are relatively frequent.[10] During the studied period from January 2001 to October 2002, Southern Norway was a high price bottleneck area in 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, but economically small markup; the estimated Lerner index is 1%. Steen argues that this evidence suggests mergers and acquisitions to be viewed with caution, as they lead to increased market concentration. In fact, transmission constraints were raised as a concern when the largest Norwegian producer, Statkraft, was allowed to acquire one of its smaller competitors, Agder Energi; see Skaar and Sörgard (2006) and references therein for a summary of the debate.

An alternative methodology: Johnsen et al. (2004) devise an alternative methodology for estimating whether bottlenecks lead to market power. This methodology has parsimonious 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 different demand elasticities and across areas with and without binding transmission constraints.

More specifically, demand is assumed to be more elastic (price sensitive) during the day than the night[11] so that the firms have more scope for exercising market power during the night. Suppose it is possible to identify a good control area for the congested area, that is, a price zone which is not congested and which is similar to the congested area in terms of marginal costs. Then, observed differences in prices between the treatment and control area and across periods with different demand elasticities should capture the extent to which firms' market power increases due to transmission constraints in low elasticity periods (i.e., during nights).

Johnsen et al. have hourly price data mainly for the year 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 prices by 15% during nights. In the other price areas, no such increases in market power were observed.

4.2.3 Evaluation

The main appeal of the behavioural methods discussed above 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 main weakness of the behavioural methods is the amount of structure required on the econometric model in order to quantify the effects.[12] In particular, 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

[10] In fact some congestion on the transmission grid is probably optimal; absence of congestion would suggest that overinvestment in transmission has occurred.

[11] Assuming that demand is less elastic during the night makes sense. Large consumers, such as energy intensive industries, are not very active on the market for electricity during the night. It is mainly these consumers who can adapt their demand for electricity to short run changes in electricity prices.

[12] Behavioral methods have also been criticized for lacking a proper theoretical foundation; see, e.g, Kim and Knittel (2006).

some firms may pursue other objectives than profit maximization, which would break the postulated link between the observed variables and observed 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 these studies find the (short term) estimated demand for electricity to be inelastic. This appears to be reasonable, since only few large consumers can adapt their electricity consumption in the very short run. In this sense, the estimates of demand suggest that the linear specification, despite being only a rough approximation, is satisfactory enough.

Due to the predominance of hydropower in the Nordic countries, it is more difficult to determine an appropriate functional form for the firms' marginal cost. In electricity markets dominated by thermal production, e.g., California and the UK, estimates based on engineering data suggest that the industry marginal cost is increasing and convex (e.g., Wolfram 1999, or Borenstein et al. 2002). In thermal markets, a quadratic specification for the marginal cost is probably satisfactory. Hjalmarsson (2000) argues that such a specification is reasonable also for the Nordic electricity market. He argues that marginal costs are constant and low at low levels of output due to a predominance of hydro and nuclear production, but increases at higher levels of output when thermal production is introduced. However, it is only the monetary cost of hydro production which is low (near 0). The relevant cost is the alternative cost of water, as measured by the water value. The water value may well be large in periods of scarcity and can 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.

There is evidence to suggest that the estimates of market power in electricity markets are sensitive to the functional form chosen for the marginal cost functions, e.g., Wolfram 1999, Kim and Knittel 2006. Kim and Knittel find in a study of the California electricity market the indirect measures of marginal costs obtained through behavioral methods to be significantly lower than the direct measures of marginal costs. This suggests that behavioral methods overestimate the degree of market power. Furthermore, their study also suggests that the strength of the bias depends on the choice of functional form.[13]

A static framework such as the Bresnahan-Lau model may be inadequate to 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 dependencies of water values. Note that 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 demand persistence, for example. 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, there have been no attempts to compare Bresnahan-Lau estimates of marginal costs with direct measures in the Nordic electricity market. In principle, however, such a study is feasible. Direct measures of marginal costs could be obtained by combining the estimated water values from simulation models with

[13] There have been attempts to evaluate behavioural methods in markets besides electricity where 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.

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 behavioral 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 methods.
Finally, there are other behavioural models besides the Bresnahan-Lau approach which can be used to study the Nordic electricity market. Kim and Knittel (2006), for example, study market power in the Californian electricity market using a model with a number of strategic firms facing a competitive fringe. Wolak (2003) uses a so-called supply function equilibrium model, specifying the equilibrium bid curves submitted by each firm. The Wolak approach is general in the sense that its application does not rely on the specification of particular functional forms for supply and demand. A drawback of the two approaches is that they are more demanding in terms of data requirements 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 than the Wolak model; the data on the produced quantities of electricity 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 the Nordic electricity market. This suggests that more detailed data would be highly valuable in order to test 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. There are several aspects to market power that mark-ups are unable to capture, which could be of importance to the Nordic market. First, price less marginal production cost is a short term measure of market power. It does not take into account investment incentives. 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 how much to produce given their capacities. In the longer run, firms must decide how much to invest in capacity. The investment decisions are subject to the same trade-off as short run production decisions. On the one hand, additional capacity leads to higher profits through an output expansion. On the other hand, the profitability of the installed capacity goes down due to the resulting price reductions.

The trade-off is illustrated in Figure 10. 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*. Base-load profit now is $(p-a)(k+x)$ and equal to the sum of the dark shaded area and the dotted area. Most of the effect of the investment is on the price rather 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.

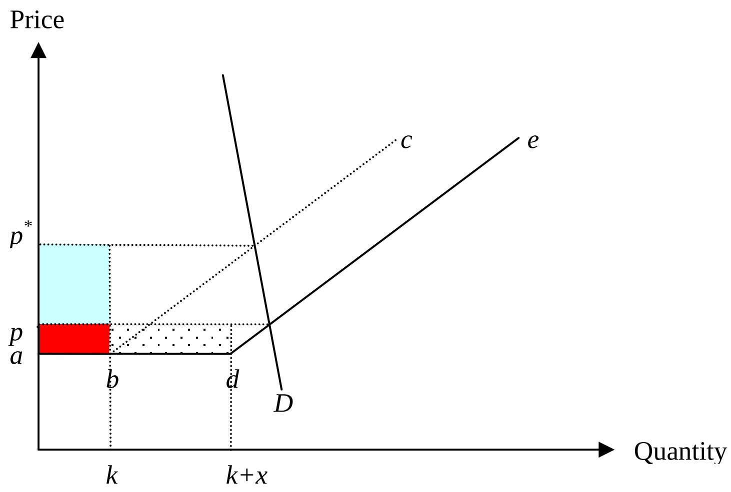


Figure 10: Long-run market power

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 10), but would only consider the profit associated with the capacity expansion (the dotted area in Figure 10). Entry would occur if the investment cost was smaller than the dotted area. An incumbent might foresee this chain of events and choose to undertake the investment itself to deter entry.

Historically, investments by incumbents and entrants have been limited by severe legal and political barriers to building new capacity in the Nordic power market. In addition, imports are bounded by limited transmission capacity. Thus, underinvestment in generation capacity could be due to a combination of market power and exogenous investment barriers. 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. With the war on global warming sailing high on the political agenda, investments in renewable energy are highly engouraged. Over the next decade, planned investments in wind power and nuclear capacity in Sweden alone amount to nearly 20 billion Euros (Svensk Energi 2008).

Finally, overinvestment in theory can be used to block entry. An incumbent firm which has invested in idle 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 investment would manifest itself as idle production capacity and short term market power.

5.2 Vertical integration and buyer power

The Nordic wholesale electricity 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.

The incentives of a strategic buyer are illustrated in Figure 11. We assume that power is supplied competitively, equal to marginal production cost and 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^*.

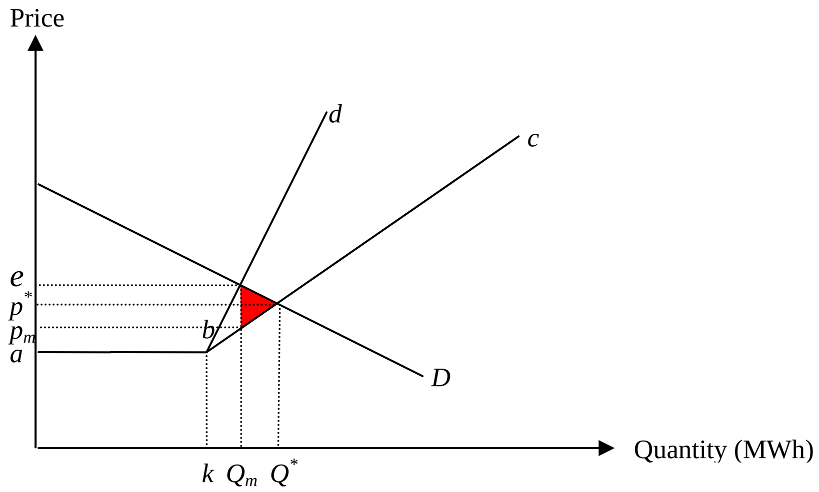


Figure 11: Buyer power

The strategic buyer takes account of the upward effect on prices. Thus, the marginal purchase cost, *MUC*, is higher than the price. In Figure 11, *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 11.

The conventional measure of seller market power - the difference between price and marginal production cost - cannot detect the presence of buyer power. In Figure 11, the price is always equal to marginal production cost. Instead, market power generates 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 directly observed. 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.[14] Vertical integration may introduce additional strategic considerations related to the retail market. For example, it could be profitable to use the wholesale price to raise the costs of non integrated rivals, thereby gaining a competitive edge in the retail market.

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 have an incentive to exercise market power also in non-marginal units. Assume that non-base-load production is supplied competitively, as in Figure 12 below. Industry marginal production

[14] Bushnell et al. (2008) show in a study of the liberalized US markets that integration between wholesale and retail significantly impact 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.

cost is given by the line segment *adbc*. It is constant up to the point *k* at which base-load, e.g., nuclear production, is fully utilized and linearly increasing 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 is still equal to the marginal cost of the most expensive unit.

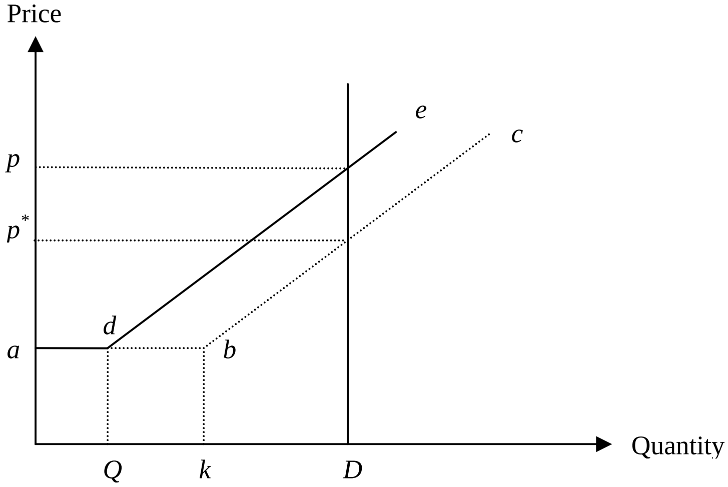


Figure 12: The effect of reducing base-load capacity

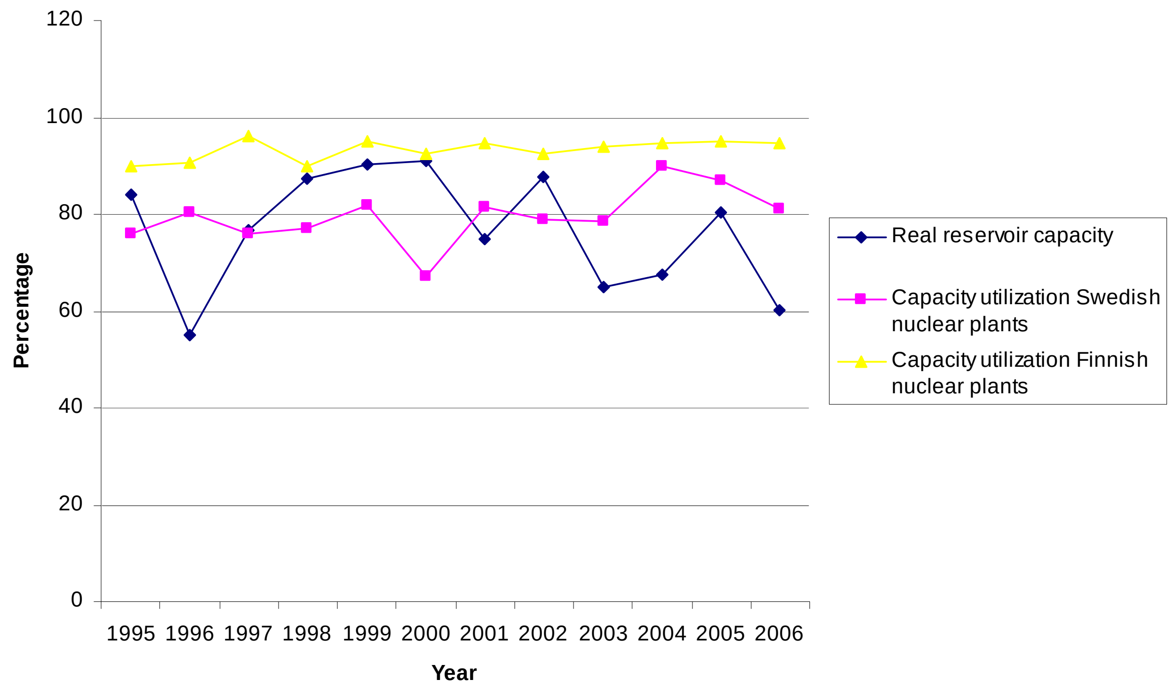
Reliable plant capacity numbers are crucial to the estimation of market power. Unfortunately, it may be difficult to disentangle unplanned or prolonged maintenance stops from strategic withholding of production. This is particularly relevant to nuclear plants. For example, it is hard to see how a competition 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.[15] 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.

[15] 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%, respectively, of nameplate Swedish nuclear capacity.

As Figure 13 shows, capacity utilization 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.[16] The question is whether this as a sign of market power.

Figure 13: Capacity utilization in Swedish vs. Finnish nuclear power plants



Sweden relies more on hydro power than Finland as hydro capacity is larger in Sweden, and transmission capacity to the hydro-dominated Norway is larger. In a wet year there is less need for nuclear production than in a dry year. Thus, nuclear production should be expected to fluctuate more in Sweden than in Finland in a competitive market. Figure 13 displays also late summer (week 30) Norwegian reservoir capacity. Indeed, there is negative relationship between reservoir levels and Swedish nuclear production (the correlation coefficient -0.4), but the statistical significance is weak (the p-value is 0.099). 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 the bulk of electricity being 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 often are 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

[16] Plant utilization numbers are from EME Analys (2007). Reservoir level data are from Norges Vassdrags- og Energidirektorats (NVE) website http://www.nve.no/ and from Statistics Norway (2000). Capacity utilization in Sweden was above the global average, 87,1% respective 82,3% from 2003-05 (Liski 2007).

for estimated welfare effects of market power. A rigorous welfare analysis of electricity markets should appropriately account for pollution costs.

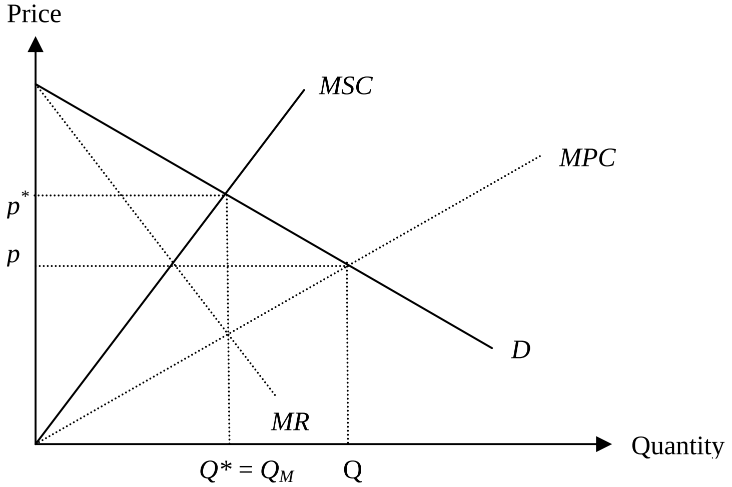


Figure 14: Market power and environmental policies are substitutes

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 and is good for the environment benefits if it reduces over-consumption. This effect is illustrated in Figure 14. Demand is given by *D*. Socially optimal consumption is where the market clearing price p^* equals the marginal social cost, *MSC*. In competitive equilibrium, the market clears at marginal production cost, *MPC*. Electricity is priced too low, at *p*, and 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., $Q_M = Q^*$.

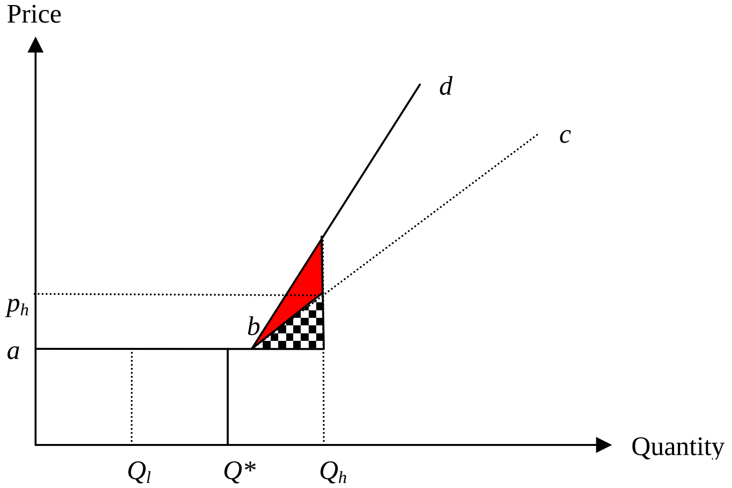


Figure 15: The environmental cost of market power in a hydro-thermal system

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 15. 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 is increasing 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 we have reviewed in this report produce no evidence of blatant and systematic abuse of wholesale market power in the Nordic electricity market. On average, the system price deviates only marginally from the competitive benchmark, and it is far from obvious that the source of recorded differences is the exercise of market power. Consequently, there is no obvious rationale for intervention, either by means of price regulations or alterations in the market design, such as a regime shift from uniform to pay-as-bid auctions.

There is some evidence to support the notion that the generation companies from time to time are able to take advantage of capacity constraints in transmission to wield regional market power. To the extent that transmission constraints become more restrictive in the future, the problem of local market power could be expected to increase. Ideally, cost benefit analyses of transmission investments should take the pro-competitive effects of investments on regional competition into account. Moreover, there is reason to examine the effects on competition of the law which states that all international transmission lines must be at least 50 per cent state-owned, and which effectively blocks private investments in transmission.

Based on the available results, it is tempting to conclude that the Nordic power market is close to competitive. The above results indicate that we must look elsewhere for market power than to short run deviations from competitive pricing. We have argued that market power can materialize in a number of ways besides short run manipulation of marginal production. Examples include underinvestment in new capacity, exploitation of buyer power and withholding of base-load (nuclear) capacity. Empirical assessments of the significance of these alternative ways of exercising market power would in our view be highly valuable.

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