The Nordic electricity market—continued success or emerging problems?

Lars Bergman*

Summary

■ Between 1996 and 2000, the national electricity markets in Denmark, Finland, Norway and Sweden were integrated and a new regulatory framework, opening up for competition in generation and retailing, was implemented. In addition, a common power exchange was established, and border tariffs between the countries were abolished. Thus, the electricity market reforms in the Nordic countries preceded and were more far-reaching than the EU electricity market directive.

The experiences of the integrated Nordic electricity market accumulated so far suggest that supply reliability has been maintained, and that "active" electricity customers have benefited from lower prices. Moreover, the integration of the national markets lead to a dilution of the market power previously held by the major generators on their respective national market, and in spite of significant entry barriers, market power has so far not appeared to be a major problem.

As demand and capacity utilisation grow, however, the possibilities to exercise market power will increase, particularly if additional mergers between generators will take place. The Lack of markets for hedging price and quantity risks seems to create economies of integration between generation and supply, and in effect establish entry barriers to the retailing segment of the market. Thus, merger control both on the wholesale and the retail market may have an important role to play. Moreover, the transmission system operators can contribute to a competitive electricity market by maintaining a certain slack in the interconnectors between the Nordic countries.■

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Like in most European countries, the national electricity markets in the Nordic countries (Denmark, Finland, Norway and Sweden) used to be protected from foreign competition, tightly regulated and dominated by vertically integrated publicly-owned[1] power companies. In the 1990s, however, far-reaching reforms were implemented and by the turn of the century, the four national markets had been transformed into a (close to) fully integrated electricity market with competition in generation and supply[2] and a common power exchange (Nord Pool).

Although the Nordic countries are small in terms of population, the level of per capita electricity consumption is quite high, particularly in Norway and Sweden. Thus, in 2001 the total consumption of electricity in the Nordic countries was 393 TWh. This is less than the corresponding figures for Germany (550 TWh) and France (450 TWh), roughly equal to the electricity consumption in the UK (360 TWh) and considerably more than in Italy (300 TWh) and Spain (200 TWh)[3]. In other words, the Nordic electricity market is one of the major electricity markets in Europe.

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[1] In Denmark, however, the power companies have been and still are owned primarily by municipalities and consumer cooperatives.

[2] The electricity supply industry is a network industry in which generation is the "upstream" activity. The network infrastructure consists of transmission grids and local distribution networks, while "supply" (or retailing), i.e. metering and billing of final consumers, is the "downstream" activity.

[3] The numbers refer to the situation in 1999.

The electricity market reform in the Nordic countries[4] preceded the EU electricity market directive[5] and has been more far-reaching than what is prescribed by that directive. In particular, the reform process in the Nordic countries has included both the elimination of border tariffs and a set of other measures aimed at establishing a multinational integrated market for electricity. In addition to the creation of the common power exchange, Nord Pool, the establishment of a close cooperation between the transmission system operators (often referred to as the TSOs) in the four countries has been the key element in that part of the process. The EU directive, in contrast, only concerned the regulatory framework of national electricity markets within the union.

The design and implementation of the electricity market reform in the Nordic countries can be seen as a major experiment in market-based allocation of an essential service. The hypothesis to be tested, or the underlying belief, is that competition can produce better results in terms of efficiency and low prices than traditional regulation. Needless to say, the importance of this "experiment" extends far outside the power industry and the electricity market. However, the electricity market is an excellent "laboratory" for this kind of experiments. Electricity is an extremely standardised product, and the reform implied a fast and complete change from regulation to competition. Thus, it is very likely that new trends in the development of power industry costs and electricity prices in the Nordic countries will primarily reflect changes in market institutions and regulations rather than changes in technology, and the lessons from the electricity market reform may have implications for regulation and competition policy in many other sectors of the economy.

The initial experiences of the electricity market reform in the Nordic countries are quite positive. First and foremost "the lights did not go out"[6]. This shows that decentralised production and consumption decisions within the framework of the new market institutions, together with traditional fine-tuning by the system operators, have man-

[4] Denmark, however, has been lagging behind and the Danish electricity market was not fully integrated in the Nord Pool system until the end of 2000.

[5] For a discussion of the EU electricity market directive, see Bergman et al. (1999). For a discussion of the earlier history of the Nordic electricity market, see Hjalmarsson (1996).

[6] In contrast, electricity consumers in California have experienced numerous "blackouts".

aged to maintain the necessary minute-by-minute balance between generation and demand. It should be noted that, due to changes in climatic conditions between individual years, the annual supply of hydropower in Norway and Sweden has varied quite significantly in the late 1990s. Thus, the electricity market has continuously cleared in spite of quite significant "supply shocks".

In addition to this basic achievement of the new market institutions, the electricity prices in the Nordic countries have fallen and, according to the scanty evidence that is available, productivity has increased in the electricity supply industry. These observations not only suggest that competition can in fact produce increased efficiency and lower prices, but also that the new market institutions and regulations are well-designed and able to foster continued efficiency increases to the benefit of electricity consumers in the Nordic countries[7].

However, while continued success may seem likely, it is also clear that the early experiences of the "new" Nordic electricity market reflect certain favourable but temporary conditions. One is that the legacy of the "old" electricity market was overcapacity in generation and transmission. As demand has been growing quite slowly during the 1990s, this means that there has been no need for investments in new generation capacity, and that bottlenecks in the transmission system have only temporarily divided the Nordic market into regional submarkets. Another favourable condition was that the integration of the national electricity markets implied a dilution of the market power of the major generators, in particular the market power of Vattenfall on the Swedish electricity market. Thus, there was no need to implement competition policy measures in order to create a reasonably competitive market.

Needless to say, these favourable conditions will not last forever. Electricity demand is growing and eventually new generation capacity will be needed, both for base load and peak load purposes. It remains to be seen how well the new market institutions and regulations will transform the increasing scarcity of capacity into investment incentives for generators and transmission system operators. Moreover, unless the entry of new generators or a further geographic extension

[7] It could be added that the availability of significant amounts of hydropower capacity in Norway and Sweden makes it relatively easy, and cheap, to continuously adjust generation to variations in demand. Thus, the Nordic "model" may not function as well in an environment where hydropower capacity is not available.

of the market can maintain competition, mergers and increasing cross-ownership relations between generators may re-establish part or all of the market power that was diluted when the national markets were integrated.

The purpose of this paper is to discuss some of the features of the market institutions and regulations that in various ways may threaten the continued success of the Nordic electricity market. The focus is on the development of electricity prices in Sweden and the implications for sector-specific regulations and competition policy measures in Sweden. Section 2 gives a relatively detailed description of the Nordic electricity market, in terms of consumption patterns, production and firms, market structure and regulation. In Section 3, competition and prices on the wholesale market are discussed. The key issue is whether market power is being exercised to the extent that additional competition policy measures are needed. Section 4 deals with the retail market in Sweden. Again, the focus is on the need for additional competition policy measures. In Section 5, finally, concluding remarks are made.

1. The structure and regulatory framework of the Nordic electricity market

For a long time, the growth in electricity consumption in the Nordic countries was high, particularly during the first decades after World War II. Later on, however, this growth slowed down significantly and in the 1990s, the growth rate was only 1.2 per cent per annum. Thus, the electricity supply industries in the Nordic countries have been faced with both increased competition and a slowdown of growth in demand. In this section, the current structure and regulatory framework of the Nordic electricity market will be briefly described.

1.1. The consumption of electricity

As mentioned in the introductory section, the per capita consumption of electricity is high in the Nordic countries. Thus, while the average per capita consumption of electricity in EU is around 6 800 kWh, the corresponding numbers are 27 100 kWh for Norway, 16 700 kWh for Sweden and 15 600 kWh for Finland. In Denmark, the per capita electricity consumption was around 6 900 kWh, i.e. close to the EU average[8]. There are two major factors behind the significant differences between Denmark and the other Nordic countries. The first is that electricity-intensive industries play a major role in the economies in Finland, Norway and Sweden, the second is the widespread use of electric heating in these countries. Table 1 summarises the level and pattern of electricity consumption in the Nordic countries in 2001.

In terms of the economic impact of electricity price changes, two key groups of customers can be identified. The first is a relatively small number of export-oriented industrial customers, primarily in the paper and pulp, steel, aluminium and chemical industries in Finland, Norway and Sweden. For these industries, the cost of electricity is between 4 and 10 per cent of the total production cost. The second is a relatively large number of households in Finland, Norway and Sweden with electrically heated homes. A representative household with electric heating consumes 20-25 MWh of electricity per annum, and the cost of electricity may be in the range of 6-10 per cent of total household expenditures. For other groups of customers, electricity is a small cost item.

Table 1. Electricity consumption in the Nordic countries 2001 (TWh)

	Total	Denmark	Finland	Norway	Sweden
Industry	162	10	45	52	55
Residential, commercial and transportation[a]	204	23	34	64	83
Losses	27	2	3	10	12
Total	393	35	82	125	151

Note: [a] Includes refineries and district heating, which in the case of Sweden was 5.2 TWh.
Source: National Swedish Energy Administration (2002).

1.2. The production of electricity

From a technological point of view, the Nordic power generation system is rather mixed, although the share of hydropower is much higher

[8] It should be noted that in terms of population, Denmark, Finland and Norway are roughly equal, while the population in Sweden is around twice as big as in each one of the other three countries. Moreover, the per capita income levels do not differ much between the four Nordic countries.

than in the rest of EU. As can be seen in Table 2, however, the national systems exhibit significant differences with respect to the relative shares of various generation technologies with most of the hydropower capacity located in Norway and Sweden[9]. This means that, depending on climatic conditions, the gross flows of electricity across the national borders can be quite significant and may change direction from one year to another. Thus, Norway is a net exporter in "wet" years and a net importer in "dry" years.

Table 2. Electricity production (TWh) and installed capacity (GW) in 2001

	Total	Denmark	Finland	Norway	Sweden
Hydro power	213	-	13	121	79
Wind power	4	4	-	-	0
Nuclear power	91	-	22		69
CHP[a]	38	2	25	1	10
Condensing power and gas turbines	41	30	11	-	0
Total annual production (TWh)	388	36	72	122	158
Total installed capacity (GW)	88.9	12.5	16.8	27.9	31.7

Notes: [a] CHP=Combined heat and power.
Source: National Swedish Energy Administration (2002).

The installed capacity, which is shown in the last row of Table 2, is a measure of the maximum hourly demands that can be satisfied. As there are transmission constraints between and within the countries, the peak load problems usually have to be managed within each country, and not all installed capacity within the country may be available to balance peak loads in certain areas.

In the context of peak load capacity, it should be noted that a significant amount of capacity (6.5 GW) has been closed down after 1996. More than half of these capacity reductions (3.8 GW) have

[9] The difference between the aggregate consumption figure in Table 1 and the aggregate production figure in Table 2 is equal to the net import from Germany, Poland and Russia. It should be noted that the Finnish import of electricity from Russia was around 10 TWh.

taken place in Sweden. As a result, the margin between the expected maximum load, which is around 29 GW, and available installed capacity is currently quite small. This issue will be discussed in some detail in section 5.

Table 3. Production by major power companies 2001 (TWh)

Company	Production (TWh)	Share of production (%)
Plants located in Sweden		
Vattenfall	76.6	20
Fortum	29.6	8
Sydkraft	32.7	8
Total in Sweden	157.8	41
Plants located in Norway		
Statkraft	33.3	9
Norsk Hydro	9.8	3
Total in Norway	121.9	31
Plants located in Finland		
Fortum	40.4	10
Pohjolan Voima Oy	15.9	4
Total in Finland	71.6	18
Plants located in Denmark		
Elsam	16.1	4
Energi E2	11.8	3
Total in Denmark	36.0	9
Total in the Nordic countries	387.3	100

Source: SOU (2002).

Table 3 depicts the production of electricity by major producing companies in 2001. The table shows that Vattenfall and Fortum have a dominating position on the national markets in Sweden and Finland, respectively. If the Nordic electricity market is considered as an integrated market, however, the situation is quite different. Thus, in terms of C4, the degree of concentration is 0.53, while the value of HHI is around 850. Accordingly, the degree of concentration is rather low, and on the basis of these measures, market power does not seem to be an obvious problem.

Needless to say, market power is a key issue in relation to electricity market reforms aimed at establishing efficient competition. The issue will be discussed in some detail in the ensuing section, but it should immediately be stressed that in order to make a proper analysis of market power problems on electricity markets, more than simple concentration measures are needed. One of the additional concerns is that cross-ownership between major generators[10] tends to increase market power. In view of that, it should be noted that Statkraft, with 10 per cent of the generation market, is a minority owner in Sydkraft with 7 per cent of that market. Thus, the power companies should not necessarily be regarded as entirely independent players on the market.

1.3. Inter-connector capacity

If the inter-connector capacities were insufficient, the Nordic electricity market would frequently disintegrate into a set of separate national markets, and the dominating position of Vattenfall and Fortum on the Swedish and Finnish electricity markets, respectively, would be a problem from the competition point of view. In Table 4, some data on current inter-connector capacities between the Nordic and other neighbouring countries are presented. The corresponding capacities between the non-Nordic countries are not included in the table.

As can be seen in the table, the inter-connector capacity between Norway and Sweden is quite high in comparison to the corresponding capacities between the other countries. In relation to the peak demand in Sweden and Norway, the inter-connector capacity is around 15 and 20 per cent, respectively. The limited export capacity from Norway to Finland means that a considerable part of the Norwegian export to Finland is imported to and re-exported from Sweden.

[10] See Amundsen and Bergman (2002).

Table 4. Inter-connector capacities 2001 (MW)

From/ To	Den-mark	Fin-land	Nor-way	Swe-den	Ger-many	Po-land	Rus-sia	Export capa-city
Denmark		-	1000	2340	1800	-	-	5140
Finland	-		100	1650	-	-	60	1810
Norway	1000	100		4250	-	-	50	5400
Sweden	2020	2050	4250		600	600	-	9520
Germany	1800	-	-	600		*	*	
Poland	-	-	-	600	*		*	
Russia	-	1000	50	-	*	*		
Import capacity	4820	3150	5350	9440				

Source: Nordel and National Swedish Energy Administration (2001).

1.4. The regulatory framework

Transmission and distribution are natural monopolies, while generation and supply are the potentially competitive segments of the electricity supply industry. This means that two types of regulations are needed in order to foster efficiency. The first is traditional regulation of natural monopoly prices, service quality and investments. The second is regulation aimed at securing competition in generation and supply, for instance by preventing cross-subsidisation or removing entry barriers.

The common features of electricity market reforms in all countries are that third-party access (TPA) to the network infrastructure is granted, and that some kind of unbundling of generation, transmission and distribution is implemented. However, both the conditions for TPA and the degree of unbundling enforced may differ significantly between countries. In addition, there may be transition periods during which only customers with an annual electricity consumption above a certain threshold level have access to the open market.

The EU electricity market directive, which became effective in February 1999, prescribed some minimum requirements with respect to TPA, unbundling and market opening. At the same time, the member states were allowed to choose between alternative ways of complying with these minimum requirements. Moreover, the directive included provisions aimed at stimulating the use of renewable forms of energy as well as provisions designed to satisfy so-called public-service obligations (PSO). As mentioned above, the electricity market reforms implemented in the Nordic countries in general are more far-reaching than those prescribed by the EU directive.

Table 5 summarises the key requirements of the EU directive and the choices made by the Nordic countries. In order to make the table understandable, the specific terminology should be briefly explained. Thus, regulated third-party access (rTPA) means that transmission and distribution tariffs are public and subject to regulation. In contrast, negotiated third-party access (nTPA) implies that these tariffs are negotiated between the owner and the users of the transmission and distribution networks, and that the details of the negotiated tariffs are not made public. "Unbundling" refers to the requirements for vertical separation between generation, transmission and distribution. "Market opening", finally, refers to the minimum share of electricity supply consumed by customers with full access to the open market.

Table 5. Elements of the EU directive and regulations in the Nordic countries

	EU Directive	Denmark	Finland	Norway	Sweden
TPA regime	rTPA or nTPA	rTPA	rTPA	rTPA	rTPA
Unbundling	Management and accounting separation	Management and accounting separation	Legal separation	Management and accounting separation	Legal separation
Market opening	30 % (as of February 2003)	100 % (as of January 2003)	100 %	100 %	100 %

The EU directive requires that the management of transmission and/or distribution is separated from the management of generation and/or supply within the same power company, and similar rules apply for economic accounting. Finland and Sweden, however, have taken one step further and require a legal separation of natural monopoly and competitive activities. Thus, power companies with both generation and transmission assets had to be divided into a generation company and a transmission company. However, generation and transmission companies are still allowed to have the same owner. In view of this, it is far from obvious that the legal separation would do any better than management and accounting separation in terms of creating "Chinese walls" between the natural monopoly and the competitive segments of the electricity supply industry.

In the EU directive, "distribution" is regarded as one single activity, i.e. there is no distinction between the physical distribution of electricity and the services associated with supply (i.e. metering, billing and insurance against price fluctuations). In Sweden, however, legal separation is required between distribution and supply. Thus, when the new electricity market legislation became effective in 1996, all distribution companies were divided into a network company and a supply company.

The legal separation of distribution and supply companies has opened up for a rapid structural change of the Swedish electricity supply industry. In 1995, there were around 250 integrated electricity distribution companies. Local municipalities owned the majority of these, but some were owned by generating companies or local associations. In 2001, the number of network companies was around 200, while mergers and acquisitions had reduced the number of supply companies to around 140. Moreover, the reduction in the number of supply companies also implied an increased integration between generation and supply. The potential impact on the degree of competition in electricity supply will be discussed in section 3 below.

1.5. Market institutions and price-risk management options

Nord Pool is an independent company jointly owned by the transmission system operators (i.e. the TSOs) in Norway (Statnett) and Sweden (Svenska Kraftnät). Nord Pool operates two "physical" and several financial markets. The key physical market is Elspot, which is a day-ahead market for standardised hourly contracts for physical delivery. Around 200 generators, suppliers and major consumers participate directly at Elspot, and approximately 30 per cent of the electricity consumed in the Nordic countries are traded at Elspot. The rest is delivered on the basis of bilateral contracts between generators and major customers. The other physical market operated by Nord Pool is called Elbas. The role of Elbas is briefly discussed in the ensuing subsection.

The financial markets operated by Nord Pool include Eltermin and Eloption. At Eltermin, standardised futures and forward contracts are traded. Using these instruments, the buyers and sellers of electricity can hedge against Elspot price risks up to four years into the future. Eloption is a relatively new market for options. In addition to the organised trade with financial contracts, Nord Pool also offers a clearing service to the parties in bilateral contracts. In addition to the financial trade at Nord Pool, there is OTC-trade with financial contracts organised by brokers.

In Table 6, the development of trade at Nord Pool between 1996 and 2000 is summarised. As can be seen in the table, the volume of physical trade has increased by more than 20 per cent per annum since 1996. At the same time, the volume of financial trade has grown from being approximately equal to becoming almost four times bigger than the volume of physical trade.

It should be noted that, due to transmission capacity limitations, the Nord Pool area is from time to time divided into a number of "price areas". Sweden is one single price area, and the same applies to Finland. In Denmark, however, there are two price areas[11], and Norway is divided into five price areas[12]. As long as the transmission system capacity is sufficient, the Elspot "system price", which is determined under the assumption that there are no transmission constraints, and the "area prices" are obviously equal. However, whenever there is congestion in the transmission system between the countries or within Norway, area prices differ from the system price. As the financial contracts traded at Eltermin and Eloption are based on the system price, these cannot be used to hedge against area price risks. In order to remedy this situation, Nord Pool has recently opened a market for so-called CFDs (Contracts For Differences) and thus offers an insurance against deviations between the system prices and area prices. However, so far the trade is quite small and the liquidity of the CFDs is consequently rather low.

Table 6. Trade at Nord Pool 1996-2001

Volume, TWh	1996	1997	1998	1999	2000	2001
Physical contracts	40.6	43.6	56.7	75.9	96.9	111.9
Financial contracts	42.6	53.0	89.1	215.9	358.9	909.9
Clearing of bilateral contracts	*	147.3	373.4	683.6	1179.5	1747.5

Note: * This service was not offered until 1997.
Source: Nord Pool.

[11] The Danish power system is, in fact, divided into two separate systems. However, each system is connected to the rest of the Nordic electricity market via Sweden and/or Norway.

[12] The differences between Norway and Sweden with respect to the number of price areas will be discussed in the sub-section on transmission management and pricing.

1.6. System operation

In spite of some minor differences, the system operation, i.e. the balancing of generation and demand in real time, is organised in essentially the same way in the four Nordic countries. To avoid repetition, the discussion is therefore confined to the situation in Sweden, but some differences between the Nordic countries will be pointed out.

The government agency Svenska Kraftnät (SVK) is the sole owner and operator of the transmission system and responsible for the system operation. The key instrument used for this purpose is a specific market, "The Balance Service", at which SVK can buy and sell power in real time. Generators can place bids for up- or down-regulation at the Balance Service, i.e. declare how much they are prepared to increase or decrease their generation at short notice, at various prices of balancing power. If there is a need for up- or down-regulation, SVK activates a sufficient number of bids, and all generators that are asked to increase or decrease their generation are paid in accordance with the marginal accepted bid.

The amount of power traded at the Balance Service to a large extent depends on how well the Elspot and Elbas markets work. It also depends on the incentives of generators, suppliers and major consumers to be "in balance" in each individual hour, i.e. to generate and/or buy as much power that is sold or consumed by the agent in question. In this context, the generators, suppliers and major consumers who have assumed the role of "balance responsible parties" (BRPs) play a crucial role. A BRP is financially responsible to be in balance in each individual hour. Every generator, supplier and consumer either has to be a "balance responsible party" (BRP) or have a contract with a BRP. Thus, any deviation between the amount of power generated and/or bought and the amount of power sold and/or consumed by the BRP itself and the parties it represents is regarded as a sale or purchase of balancing power, i.e. use of the Balance Service.

As the price of balancing power is generally higher than the spot market price when up-regulation is needed, and lower than the spot market price when down-regulation is needed, BRPs in general have quite strong incentives to be in balance and thus contribute an aggregate balance in the system. In Sweden, BRPs are charged for balancing power in accordance with a two-price system that makes the financial incentives to avoid adding to the aggregate imbalance of the system particularly strong. As a result, the volumes of balancing power actually bought or sold tend to be quite small.

Around 70 per cent of the electricity consumed are delivered to the final consumers on the basis of bilateral contracts. These contracts are typically signed well in advance of the actual hour of delivery. For an individual BRP, active planning and forecasting helps reduce the risk of being in serious imbalance during a specific hour. However, as there is considerable uncertainty about future hourly supply and demand conditions, the BRPs typically need to buy or sell power as the uncertainty unfolds. Table 7 below illustrates how a BRP can trade on Elspot and Elbas in order to minimise its use of the Balance Service. However, Elbas is only open to BRPs in Finland and Sweden.

Table 7. Markets and time frames

Market or type of contract	Time frame
Bilateral contracts	Days, weeks, months or years ahead
Elspot	One day ahead
Elbas	Up to two hours ahead
Balance Service	Real time

From time to time, there is congestion in the transmission system within Sweden, particularly in the north-south direction. In order to relieve transmission congestion, SVK uses bids to the Balance Service within the frame of a so-called counter-trade system[13]. The increases in generation cost resulting from these interventions are included in the fixed part of the transmission tariff.

1.7. The structure of transmission and distribution tariffs

In the context of transmission pricing, there is an important distinction between "transaction based" and "non-transaction based" tariffs. The first type of tariff assumes that a "contract path" between the seller and the buyer can be identified. The charge for transmitting the power in question is made up of charges for the transmission facilities along the "contract path". In other words, a "transaction based" tariff attempts to allocate the fixed costs of the transmission facilities be-

[13] Thus, if capacity constraints prevent some scheduled transmission of power from the north to the south from being completed, SVK activates down-regulation bids in the north and up-regulation bids in the south. As a result, supply equals demand at both sides of the transmission bottleneck.

tween the users of the network. A consequence of the adoption of a "transaction based" tariff is that transmission prices will depend on the distance between sellers and buyers, i.e. generators located close to major consumptions areas will be in a better competitive position than producers located further away.

However, in meshed networks, "contract paths" cannot easily be identified. Moreover, as is shown by Haubrich et al. (1999), transmission losses caused by an individual transaction do not depend on the geographical distance between the generator injecting power into the system at one node, and the consumer tapping power from the system at another node. Instead, the marginal transmission cost of the transaction, in terms of increased congestion and transmission losses, depends on the configuration of the system as a whole. Thus, a transaction between two parties located far away from each other may reduce congestion and transmission losses in the system as a whole and thus entail a negative marginal transmission cost, while a transaction between two parties located close to each other may have the opposite effect.

"Non-transaction based" transmission tariffs reflect these findings so that the charges only depend on the point of connection to the system and whether power is injected or tapped at that node. In other words, a "non-transaction based" tariff attempts to charge the user of the system with the relevant marginal cost of transmission. A consequence of the adoption of a "non-transaction based" tariff is that the geographical distance between buyers and sellers of power does not affect the transmission charges. However, as the charges differ between various points of connection to the system, the transmission tariff may induce a generator to choose a certain location, and thus in effect help reduce congestion and transmission losses. Compared to a "transaction based tariff", a "non-transaction based" tariff tends to widen the geographical extension of the market and is thus preferable from a competition policy point of view.

In the Nordic countries, transmission tariffs are of the "non-transaction based" type, but the details of the tariffs differ between countries. The major difference refers to the treatment of congestion. Thus, the Norwegian transmission tariff includes a congestion charge, which in effect divides Norway into two or more (up to five) regional electricity markets whenever the capacity of part of the transmission system is insufficient. The congestion charge between two adjacent regions is equal to the difference between the area prices in the regions in question[14]. In the other Nordic countries, however, the transmission tariffs only reflect the cost of transmission losses, and congestion in the transmission system is managed by means of counter-trade.

1.8. The regulation of transmission and distribution tariffs

In all the Nordic countries, the regulation of transmission and distribution tariffs is rather "light-handed". In Sweden, the net regulator is an independent unit within the National Swedish Energy Administration. The basic regulation is that tariffs have to comply with some general principles such as being cost-reflective, "fair" and relatively stable, but they do not have to be approved in advance. Customers who consider the tariffs to be in violation of the general principles can complain to the net regulator. If the net regulator considers the complaints to be justified, he negotiates with the network company in question. Usually the regulator is successful in bringing about sufficient changes in the tariff, but in case he does not, the issue will be brought to court. So far, only a few cases have been settled in court, which means that the precise meaning of the general principles referred to above to a considerable extent remains unclear.

There is no specific regulation of the structure of transmission and distribution tariffs. As a result, the tariffs differ significantly between network companies with respect to both the level and the structure in terms of fixed and variable elements. Moreover, as is illustrated by Table 8, these differences seem to be as big in 2001 as they were in 1996. The figures in the table refer to the electricity distribution prices paid by three types of representative household customers. The first type of customer lives in an apartment without electric heating and consumes 2 MWh per year. The second lives in a single-family house without electric heating and consumes 5 MWh per year, while the third is a customer who lives in a single-family house with electric heating and consumes 20 MWh per year. It should be noted that the local municipalities still own and operate most of the distribution companies.

[14] The inter-connector tariffs are designed in the same way.

Table 8. Distribution prices (EUR/MWh) for different customers 1997 and 2001

	1997			2001		
	Lower quartile	Median	Upper quartile	Lower quartile	Median	Upper quartile
2 MWh/yr	36.0	44.9	51.3	37.8	46.1	52.4
5 MWh/yr	32.3	39.1	45.6	33.8	40.4	47.2
20 MWh/yr	20.2	23.2	26.7	19.8	22.5	25.4

Note: EUR 1 = SEK 9.2 (May 2002).
Source: The National Swedish Energy Administration (2001).

There are significant economies of density in electricity distribution. Thus, the cost of distributing electricity in a sparsely populated country like Sweden should in general be rather high. It should also differ significantly between the major population centres and the countryside, particularly in the northern part of the country where the population density is very low. This means that cost-reflective distribution prices should be expected to exhibit a considerable spread. However, the spread revealed by Table 9 does not primarily reflect differences in density related costs. To a large extent, they reflect different accounting principles in the past, and different views among municipalities on the use of electricity distributions tariffs as a means to support low-income families. As shown by Hjalmarsson and Kumbhakar (1998), there are also differences in efficiency between the distribution companies.

These observations suggest that the regulation of distribution tariffs could be somewhat more stringent, and steps in that direction have recently been taken. Thus, the network regulator is currently implementing a kind of price-cap regulation of transmission and distribution services. The aim is to bring distribution prices closer to real costs, and create incentives for efficiency increases. The key instrument in this work is a simulation model, the "net utility model", which is used to calculate the cost of electricity distribution in given areas as a function of population density, the geographical extension of the area, and other factors. Using the model results as a benchmark, the actual tariffs are evaluated. If the actual distribution prices in a given area exceed the calculated benchmark prices, the net regulator may initiate negotiations about the tariff.

2. Competition and prices on the wholesale market

The wholesale market is the market where generators sell power to other generators, suppliers and major consumers. Hourly prices are determined at Nord Pool's day-ahead market (Elspot) and the prices of financial futures and forwards traded at Nord Pool, reflect the expectations about average weekly, monthly, seasonal and yearly prices held by the market participants. While only about 30 per cent of the electricity actually delivered to the final consumers are traded at Nord Pool, the prices determined at Nord Pool are reflected in the prices agreed upon in similar bilateral contracts. Thus, the prices quoted at Nord Pool can be seen as the market clearing prices for different types of contracts traded on the Nordic electricity market. The key issue is whether these prices reflect the relevant marginal costs, or if the exercise of market power has created significant wedges between prices and marginal costs.

When discussing this issue, a distinction should be made between, on the one hand, the average price level on a yearly or seasonal basis and, on the other hand, the hourly prices in certain short periods or in certain geographical areas. The average price level reflects the overall relation between supply and demand on the Nordic market as whole. A major generator may be able to exercise market power, i.e. raise the average price level on the entire market, by systematically holding back supply[15]. In general, capacity constraints in the transmission system and "price-spikes" during a small number of peak load hours play a minor role for the average price level.

The hourly prices, on the other hand, depend on demand, available generation and transmission capacity and the supply behaviour of generators during the hours in question. Thus, the possibility to exercise market power during a specific hour not only depends on the generation capacity that is available for a generator, but also on the location of that capacity and the prevailing demand conditions. Among other things, this means that also small generators may have market power during certain periods or at certain locations.

In the following, competition and prices on the Nordic electricity market will be discussed both with respect to the average price level and prices during shorter periods or in certain areas. The focus is on

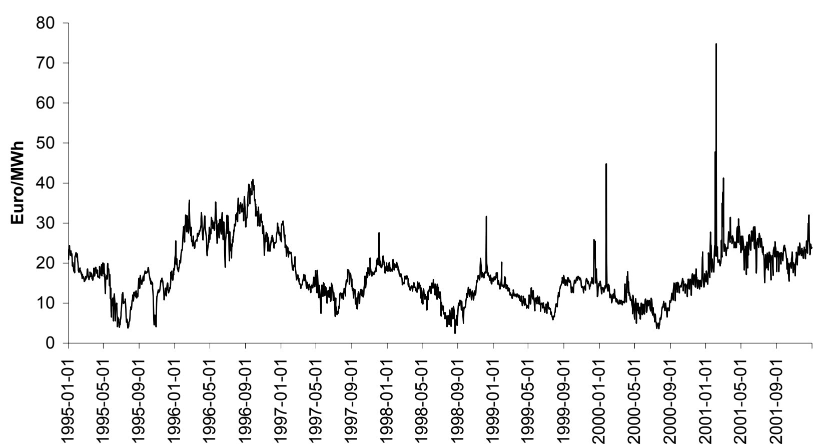
[15] As it is costly to keep a thermal generation unit available for production, there are output decisions to be made also in the short run (a few months or a year) even if the generation capacity is given.

the existence and exercise of market power, and the need for competition policy measures in order to maintain a sufficiently competitive market.

2.1. The development of spot market prices

As a point of departure, Figure 1 shows the development of spot market (system) prices quoted at Nord Pool 1995-2001. As can be seen in the Figure, the prices increased immediately after the implementation of the new electricity market legislation and the opening of the integrated Norwegian-Swedish electricity market in 1996. However, in 1997, prices fell dramatically and continued to fall until the middle of 2000. In the autumn of 2000, prices started to increase, and in the winter of 2001, there were some very significant price-spikes. In addition to the yearly variations, the spot market price exhibits both significant short-term volatility and a systematic seasonal pattern, with low levels in the summer and high levels in the winter.

Figure 1. Nord Pool system prices 1996-2001 (EUR/MWh)



Source: Nord Pool.

From the point of view of competition and market power, the development of spot market prices should be seen against the background of the marginal costs and available production capacities in the Nordic electricity supply industry. Without looking at details, the situation can be summarised in the following way:

The variable operating cost of the hydro power plants is in the range 3-7 EUR/MWh[16] and the total production capacity during hydrologically "normal" years is around 200 TWh. In the case of wind power, the variable operation cost is around 5 EUR/MWh and the annual production capacity around 5 TWh. For nuclear power plants, the corresponding numbers are 8-9 EUR/MWh and 100 TWh. The production capacity of the CHPs is around 50 TWh per year. The variable operating costs in these plants depend both on the type of fuel used and the revenues from the steam or hot water for district heating jointly produced with the power. Thus, the cost varies between 5 and 22 EUR/MWh. In the case of coal condensing power, the annual production capacity is around 50 TWh and the variable operation cost around 23 EUR/MWh.

However, due to climatic conditions, the supply of hydropower varies considerably between different years. Thus in "wet" years, up to 240 TWh can be produced in existing hydro power plants, while the maximum production in these plants can be as low as 160 TWh in "dry" years. This means that the supply of low-cost electricity from existing wind, hydro and nuclear power plants varies between 265 and 330 TWh per annum. As the annual demand is currently 380-395 TWh, this means that even if the CHPs are fully utilised, some coal condensing power will be needed. Thus, provided that the market is sufficiently competitive, one should expect the spot prices to vary between 3 EUR/MWh in the summer and 23 EUR/MWh in the winter. Figure 1 supports this hypothesis, although the "price-spikes" clearly show that the details of the development of spot prices cannot be explained unless additional factors are brought into the picture.

As the amount of coal condensing production needed varies considerably between "wet" and "dry" years, one should expect the annual averages of the spot prices to exhibit considerable variation. Table 9 below shows that the time weighted average system prices in general vary between 11 and 23 EUR/MWh, and that the variations between individual years are strongly correlated with the variations in hydrological conditions. However, so far there is no obvious trend in the development of yearly electricity prices.

[16] The cost estimates are taken from Elmarknaden 2001 (The Electricity Market 2001), Swedish Energy Administration. The conversion to Euros is based on the exchange rate in May 2002, i.e. 1 Euro=9.2 SEK.

Table 9. Average system prices and hydrological conditions 1996-2002 (EUR/MWh)

Year	Average system price	Hydrological conditions
1996	28.6	Very dry
1997	15.7	Normal
1998	13.3	Wet
1999	12.9	Wet
2000	11.7	Very wet
2001	23.2	Normal
2002	19.3	n.a.

Source: Nord Pool. The values for 2002 refer to the period January-April.

An issue that has been the subject of considerable discussion is the doubling of the average price level between 2000 and 2001. While 2000 was an extremely "wet" year, 2001 was a "normal" year. Thus, a price increase between 2000 and 2001 should be expected. However, the price increase that actually took place exceeded what was generally expected, and there was a rather common view that the major generators were somehow able to raise prices above the competitive level. As a result of these sentiments, a government committee was appointed to investigate the matter. In its report,[17] the committee later on rejected the hypothesis that the exercise of market power had influenced the development of electricity prices between 1996 and 2001 to any significant degree.

On the particular issue of the 2001 price increase, the committee came to the conclusion that the underlying factors were a combination of fuel price increases, reduced hydropower supply, increased demand and the phasing out of the Barsebäck 1 nuclear reactor. In other words, the committee did not consider the price increase to be a result of the exercise of market power. Its conclusion was based on a study carried out by a consultant company, Tentum AB. The study in question was based on simulations with a numerical model[18] of the Nordic electricity market. According to Tentum's analysis, half of the price increase between 1999 and 2001 could be ascribed to coal- and oil price increases. Around 25 per cent were due to the reduced supply of hydropower, around 10 per cent the result of increased demand and 5 per cent due to the phasing out of the 600 MW nuclear reactor Barsebäck 1.

[17] SOU (2002).
[18] See SOU (2002), pp. 91-92.

These observations suggest that the Nord Pool system prices, except for "spikes" and "dips" during certain hours, are reasonably close to the relevant marginal costs. In particular, prices seem to be close to the marginal costs both in the summer when demand is low, and in the winter when demand is high. This, in turn, suggests that the market is reasonably competitive both in peak and off-peak periods.

However, it is hardly surprising that the market is quite competitive during off-peak periods. The total installed capacity in hydro power plants in Norway, Sweden and Finland is around 47 GW, while the aggregate hourly demand on the Nordic market is less, and sometimes much less, than that most of the time between April and October. Moreover, Fortum, Statkraft, Sydkraft, Vattenfall and Graninge, as well as a number of small generating companies, all own hydro power plants, and the opportunity cost of water is usually quite low during the summer. Thus, there are a relatively large number of generators with equally low marginal costs, and a combined production capacity that exceeds demand during the period in question. Consequently, Bertrand-like competition and prices close to the marginal cost should be expected, and market power should not be a problem during the off-peak period.

During the winter period when demand is much higher, the situation is different. In this period, aggregate demand frequently exceeds the aggregate installed capacity of the small and medium sized generators. Thus, demand cannot be satisfied unless the major producers have a positive production. In certain periods, a single generator has a monopoly position in relation to the residual demand that the other generators are unable to satisfy. Accordingly, market power exists and may be exercised, and the Bertrand model of competition does not seem to be a realistic approximation of reality during the peak and near-peak periods, i.e. the late autumn, winter and early spring. Yet, the Nord Pool system prices during these periods of the year do not seem to significantly deviate from the relevant marginal costs.

However, in order to analyse the possible impact of market power, one has to focus on the Nord Pool area prices rather than the system price. The system price is, after all, an abstraction that neglects the fact that from time to time, transmission constraints affect the prices faced by generators and consumers. In the ensuing sub-section, the development of the Swedish area price and the possible impact of market power are discussed.

2.2. Transmission constraints and market power

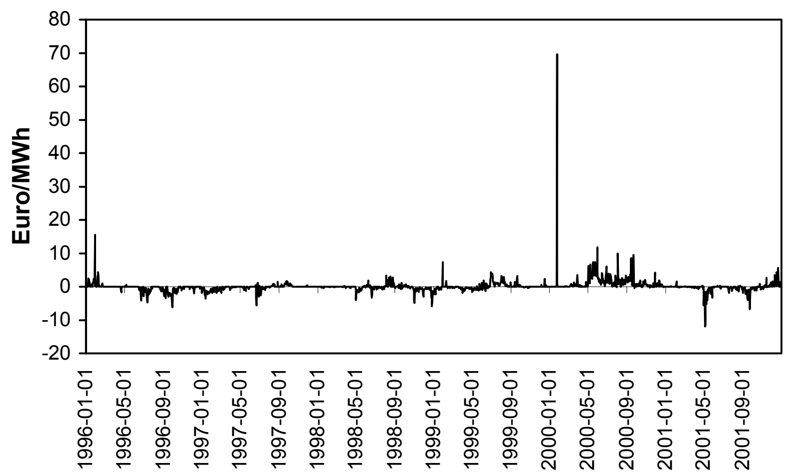
Using a numerical model, Amundsen et al. (1999) analysed the potential impact of market power on the Norwegian-Swedish electricity market. In the model, Cournot competition between the major generators was assumed, while the small generators in the "fringe" were assumed to behave competitively. One of the key conclusions was that the major generators on the Swedish market, in particular Vattenfall, were able to significantly raise the price level in Sweden under autarky conditions. Thus, during the peak period (late autumn, winter and early spring), the computed Cournot equilibrium price in Sweden exceeded the competitive price (which was used as a benchmark) by more than 50 per cent. The corresponding figure for Norway was only 2 per cent, reflecting the much lower degree of concentration on the Norwegian electricity market.

When trade across the national border was allowed, however, the difference between Cournot and competitive prices in the peak period was reduced to just below 20 per cent. Needless to say, these results illustrate that there is a close relation between the geographical extension of the Nordic electricity market and the possibilities for the major generators to exercise market power. Moreover, due to transmission constraints, the computed area price in Sweden (under Cournot competition) turned out to exceed the area price in Norway by around 15 per cent. Although the system price was not calculated in the model, these results imply that the area price in Sweden exceeded the system price, while the area price in Norway was lower than the system price. The model results also indicated that the price increase was brought about by reductions in the nuclear power production of the major generators in Sweden. Thus, it seems that the market power issue should be discussed against the background of the development of area prices and nuclear power production in Sweden. The development of the Swedish area price is displayed in Figure 2.

As shown by Figure 2, the area price in Sweden in general has not deviated much from the system price, and the deviations are not systematically positive or negative. In 2000, however, the area price in Sweden constantly exceeded the system price and in some periods, the difference between the area and system prices was quite significant. In contrast, area prices in Norway were systematically below the system price during this particular period. This means that the interconnectors were congested in the Norwegian-Swedish direction most of the time in 2000.

Under given demand conditions, congestion in the inter-connector between two areas can be caused by increases in production in one area and/or decreases in production in the other area. It has already been mentioned that 2000 was a "wet" year. Thus, production in Norway increased from close to 123 TWh in 1999 to 143 TWh in 2000. This clearly contributed to the congestion in the Norwegian-Swedish inter-connectors. However, as shown by Table 10, there were also significant reductions in the Swedish nuclear power production in 2000.

Figure 2. Difference between the area price for Sweden and the Nord Pool system price 1996-2001 (EUR/MWh)



Source: Nord Pool.

In the summer of 1999, the 600 MW nuclear reactor Barsebäck 1 was closed down and consequently, the potential nuclear power production in Sweden was reduced by around 4 TWh per year. However, the reduction of nuclear power production between 1999 and 2000 exceeded the reduction of potential production by far. It thus seems that the Swedish power producers responded to the market conditions, i.e. the very low price level, by reducing capacity utilisation in the nuclear power plants. However, in order to evaluate this behaviour of the big power companies in Sweden, the level of area prices in Sweden and Finland should also be considered. Table 11 shows the monthly averages of the system price and area prices in Sweden and Finland in 2000.

Table 10. Annual nuclear power production in Sweden 1995-2001 (TWh)

Year	1990	1995	1996	1997	1998	1999	2000	2001
Production	65.2	66.7	71.3	67.0	70.4	70.1	54.8	68.0

Source: The National Swedish Energy Administration (2001).

Table 11. Monthly system prices and area prices in Sweden and Finland 2000 (EUR/MWh)

Month	System price	Area price in Sweden	Area price in Finland
January	15.1	17.4	17.4
February	11.9	11.9	11.9
March	10.7	11.2	11.4
April	11.5	11.7	11.7
May	8.5	12.8	12.8
June	9.4	11.4	11.5
July	5.8	7.2	8.9
August	8.9	10.7	13.3
September	13.0	15.1	17.1
October	14.3	15.0	15.5
November	15.7	16.1	16.1
December	16.0	16.4	16.4
Annual average	11.7	13.1	13.7

Source: Nord Pool.

As mentioned above, the variable operating cost, i.e. the short-run marginal cost, of the nuclear power plants is 8-9 EUR/MWh. This means that in the period May-August, the system price was close to or below the short-run marginal cost of nuclear power. The area price in Sweden, on the other hand, was below the short-run marginal of nuclear power only in July. Moreover, capacity utilisation in the nuclear power plants was unusually low from late April to late August, and reached a very low level (less than 2 000 MW) in the middle of July. It should also be noted that the area price in Finland was higher than the area price in Sweden from June to October, which means that the Swedish-Finnish inter-connectors were congested during this period. Thus, producers in Finland had no incentives to sell power in Sweden, and Swedish producers could not get access to the Finnish market. In other words, the transmission capacity constraints in effect divided the Nordic electricity market into three national markets[19].

These observations suggest that the major power producers in Sweden, for a short period being protected from foreign competition, were able to raise the area price above the short-run marginal cost of the nuclear power plants. This clearly indicates that the biggest producers do have market power on the national electricity market. However, prices below the short-run marginal cost should induce producers to reduce production also on a perfectly competitive market. Thus, the development of the Swedish area price during the summer 2000 can hardly be regarded as the result of an abuse of the dominating position of the biggest power companies in Sweden.

2.3. Price-spikes and peak load capacity

As shown in Figures 1 and 2, the spot market prices exhibit both significant short-run volatility and a considerable spread between minimum and maximum prices. The extremely low prices usually reflect extreme hydrological conditions in the late spring or summer period. The price spikes, on the other hand, generally reflect peaks in electricity demand for heating purposes stemming from unusually low winter temperatures. Although electric heating accounts for a rather modest share of total electricity consumption, it is the single most important factor behind the winter peaks in electricity demand. However, there are also institutional, or "market design", factors behind the price spikes.

One is that the prices paid by household customers are usually fixed for a longer period, in many cases for 1-3 years. Thus, few households have economic incentives to reduce their consumption when hourly spot-market prices are very high. Consequently, the peak demand for electricity is extremely inelastic with respect to hourly price changes. Another factor is that there are no capacity payments in Sweden, i.e. payments to generators who keep reserve capacity available for use in hours when demand is unexpectedly high. As a

[19] In 2000, Denmark was not fully integrated in the Nordic electricity market.

result, peak capacity has been closed down, and there is currently a very small margin between available capacity and the peaks in demand that may occur on extremely cold winter days.

These problems have been the subject of considerable debate. Upon request by the government, a committee lead by the Director General of SVK is currently designing a new system aimed at strengthening the incentives to keep reserve capacity available, and increase the short-run price elasticity of demand[20].

It cannot be ruled out that a detailed analysis of spot price volatility would reveal instances when market power has been exercised. However, the problem with price spikes and the increasing risk of power shortage during cold winter days primarily seems to be a market design rather than a competition policy problem.

2.4. Entry conditions and competition in the long run

The discussion in the preceding sections suggests that, in spite of temporary transmission constraints, the creation of an integrated Nordic market for electricity has effectively diluted the market power that would otherwise have prevailed on the national markets. However, the combination of excess capacity when the new legislation was implemented and slow growth of electricity demand created a favourable environment for the new market institutions and regulations. The question is whether sufficient competition will be maintained as electricity consumption grows, and the utilisation of existing generation and transmission facilities reaches the capacity limits. The most important mechanism in this context is that an increasing price-cost margin induces investments not only by the incumbents but also by new competitors entering the market.

According to both electricity market analysts and power companies, investments in new generation capacity will not be profitable until the average price level is at least 27 EUR/MWh. As shown in Table 9, this is well above the average prices since 1996. Moreover, there are widespread concerns about increasing difficulties in getting approval for new power plants and transmission facilities. Consequently, average prices well above 27 EUR/MWh may be needed to attract new competitors to enter the market. Thus, although a limited

[20] In Norway, a new system has recently been introduced. In the new system, the transmission system operator, Statnett, buys options to use generating capacity and/or curtail demand during peak hours. See Nilsson and Walther (2001).

amount of subsidised investments in wind power and power production based on renewable energy can be expected, the incumbents do not have to fear the entry of new competitors in the near future.

From the competition point of view, further geographic extension of the market is an alternative to the entry of new competitors. In practise, this means that the capacity of the inter-connectors between the Nordic and the German electricity markets would have to be increased. It should be noted, however, that while the inter-connectors between the Nordic countries are owned and operated by the transmission system operators in the Nordic countries, the existing Swedish-German inter-connector is owned by power companies (Sydkraft, E.ON Scandinavia and E.ON Energie). The main obstacle to a significant geographical extension of the Nordic electricity market is that the current inter-connector capacities are quite small. In theory, several new inter-connector investments can be carried out simultaneously but in practise, the capacity expansion is more likely to be gradual.

2.5. The wholesale market and competition policy

The discussion about entry conditions and inter-connector investments in the preceding sub-section suggests that the Nordic electricity market will remain the same for a number of years, both in terms of the geographical extension of the market and the power companies operating on the market. However, in recent years, there have been a number of mergers between power companies, which has lead to a higher degree of concentration, for instance the significantly increased market share of Fortum. In addition, the cross-ownership between power companies has increased. One example is Statskraft's acquisition of a minority share of Sydkraft. As shown in Amundsen and Bergman (2002), the possibilities of the big power companies to profitably reduce supply, and thus raise the market price, are enhanced also by the acquisition of minority shares in other power companies.

From the competition policy point of view, the control of mergers and acquisitions is a key instrument for maintaining a competitive Nordic electricity market. In addition to traditional competition policy, and the measures taken by the competition authority, the TSOs have an important role in this context, because investments in additional inter-connector capacity within the Nordic area have two distinct effects. One is the obvious effect that less congestion in the transmission system makes it possible to use existing generation facilities more efficiently and thus reduce the aggregate cost of generation. The other is the less obvious effect of preventing the market from being divided into national markets where market power can easily be exercised. While the former effect is the traditional prime concern of the TSO's, the second may be increasingly important. Thus, the TSO's need to design investment criteria that explicitly include the competition enhancing effect of transmission system investments.

3. Competition and prices on the Swedish retail market

The Swedish retail market is unique in the sense that the supply, or retailing, companies have to be legally separated from the network companies. Moreover, it is the local network company that is responsible for metering, while the retailer is responsible for billing. The customers can choose between different types of contracts, but all existing types of contracts imply that the price to be paid by the customer is fixed for at least a month. Thus, the "product" delivered by the retailer is basically an option to consume electricity at a specific price.

This means that the retailer carries both a price risk and a quantity risk (the nature and causes of these price and quantity risks will be discussed later in this section). Consequently, the margin between the retailer' selling prices and Nord Pool area prices has to cover both the administrative costs associated with billing and the costs associated with the price and quantity risks that the retailer carries.

In this section, the development of retail prices will be discussed against the background of switching costs and market structure, in particular the increasing vertical integration between generation and retailing observed in recent years.

3.1. Retail prices and switching costs

When the Swedish electricity market reform was implemented in 1996, all customers immediately got access to the "new" market. In other countries, for instance in England and Wales, the market was gradually opened over a number of years, beginning with the big industrial consumers. However, in Sweden, there was a requirement that customers who were about to enter the "new" market[21] had to install a device that metered and reported the consumption of elec-

[21] The alternative was to retain the contract with the supplier that was previously part of the local distribution company.

tricity in real time. The cost of such a device was negligible for industrial and other big customers but rather significant for households and other customers with a small annual consumption of electricity[22]. However, in November 1999, this particular regulation was abolished, and customers without real-time meters were to be charged in accordance with standardised load profiles. In practise, this meant that the system in use in Norway was adopted.

In effect, this change of the regulatory framework meant that the switching costs faced by households were dramatically reduced. Thus, the only remaining cost for switching from one retailer to another, or to switch from an "old" to a "new" contract with the "old" retailer, was the time and effort needed for contacting the retailer and signing the contract. As can be seen in Table 12, this reduction had a significant impact on the retailers' selling and buying prices. However, before discussing the numbers in the table, a few words should be said about the definition of selling and buying prices.

In the table, the selling prices refer to the prices paid by households with electric heating, i.e. household customers with a relatively high annual consumption of electricity. The "old" selling prices displayed in the table refer to the old type of standard contract in which the price to be paid by the customer was fixed until a change in the retailer's cost motivated a change in the price. The "new" selling prices refer to contracts that the retailers started to offer when the real-time metering requirement was abolished. In these contracts, the price is fixed for a month (a so-called "variable price" contract) or for one, two or three years. The values in the table refer to prices in one-year contracts, but the prices in two- or three year contracts signed at the same point in time were approximately the same. All values for selling prices are average values of the prices charged by all retailers in Sweden.

Needless to say, the buying prices of the retailers are not made public. In the table, two types of buying prices, reflecting two alternative assumptions about the behaviour of the retailers, are displayed. The first, "Average spot prices", is the annual averages[23] of Elspot area prices for Sweden. These prices would be relevant if the retailer

[22] For a household, the cost was around EUR 1000. Later on, the network companies were obliged to install the required type of meter at a maximum cost of EUR 270.

[23] The numbers in the table are time-weighted averages. It would have been desirable to use energy-weighted averages, but no such data is available.

refrained from hedging the price risks and thus constantly bought the power needed at the spot market. The second, "Futures/Forward prices", are the futures (up to 1999) and forward (after 2000) prices for a given year specified in contracts traded at Nord Pool on September 1 the year before. The idea is that a retailer who is contracted to sell electricity at a given price also wants to buy electricity at a fixed price during that period. Moreover, the prices specified in futures/forward contracts bought on September 1 are known to the retailer well before new contracts with buyers for the coming year are signed.

Table 12. The retailers' selling and buying prices 1996-2002 (EUR/MWh)

	1996	1997	1998	1999	2000	2001	2002
Selling							
Old	26.8	32.5	27.3	26.5	23.7	24.5	32.1
New	n.a.	n.a.	n.a.	n.a.	19.3	19.7	27.8
Buying							
Average spot prices	28.3	15.6	13.1	13.0	13.1	22.9	19.3
Futures/Forward prices	n.a.	30.0*	16.5*	15.6	14.6	14.4	18.8

Notes: The value for the selling price in 1996 refers to the situation on July 1 that year, while all other values refer to the situation on January 1 in the respective year. Average spot prices for 2002 refer to the period January-April. * Average value of quarterly futures prices.
Sources: Nord Pool and Central Bureau of Statistics (SCB EN 17).

First of all, it should be noted that households that did not switch to a new retailer, or a new contract with the old retailer, have not benefited very much from the electricity market reform. In fact, as household electricity taxes increased by approximately 10 EUR/MWh between 1996 and 2002, the price of electricity paid by these households has increased. However, for households that have switched to a new retailer, or a new contract with the old retailer, the situation is different. While prices in "old" contracts went down by around 10 per cent, "active" households could get an additional 17 per cent (of the 1999 price) reduction of the price by switching to a "new" contract. In fact, some retailers offered contracts at around 15 EUR/MWh, making ever greater gains possible. Moreover, the spread between "old" and "new" prices established in 2000 has roughly been constant.

In other words, it seems that lower switching costs lead to increased competition and lower prices for "active" consumers on the retail market. Yet the number of households that has been "active" is relatively small. Thus, it has been estimated that by August 2001, 17 per cent of the households had switched to a new retailer, while 13 per cent had renegotiated their contract with the old retailer. Accordingly, 30 per cent of the households had responded to the possibility of getting a significantly lower electricity price. This may seem a surprisingly small number. However, households with a high electricity bill have been more active than others and accordingly, the share of electricity delivered to households on the basis of "new" contracts is higher than 30 per cent. No published statistics are available but a usual estimate by representatives of the electricity supply industry is 65-75 per cent. If this estimate is approximately correct, most of the households that can make a non-negligible cost saving by switching suppliers or contracts have in fact done so.

The fact that prices in old contracts remain considerably higher than prices in new contracts suggests that there is an element of third-degree price discrimination of households that have not (yet) switched. However, while such an outcome was not intended when the legislators gave households the possibility to continue with the old type of contracts, it is hardly surprising. The fact that a household has so far chosen not to switch is a signal to the retailer that it is less sensitive to electricity price changes than many other households. Retailers seem to use this information and refrain from closing the gap between "old" and "new" prices.

If price discrimination could be proved, it is still not obvious that it is a violation of the competition law. Most of the retailers who charge the "old" prices do not have a dominating position on the market, and the households paying the "old" prices are all free to switch to other retailers or contracts. However, in view of the low annual electricity bill of most of these households, it is likely that the information and transaction costs associated with a switch are too high to make a profitable switch feasible. Thus, what seems to be going on is that retailers are extracting the rent that is created by the information and transaction costs of households with a low annual consumption of electricity.

3.2. Retail prices and market structure

As can be seen in Table 12, the selling prices increased significantly between 2001 and 2002. One obvious reason for this was the increase in wholesale prices in 2001. However, this is not the only reason; the increase in the selling price clearly exceeded the increase in the wholesale price. Another reason could be the fact that a large number of electricity retailers were suffering unsustainable losses. In some cases, the losses were due to unsuccessful speculation in further reductions of the wholesale price. Thus, some retailers had gained customers by offering low fixed prices, while expecting that the electricity needed to honour the contracts could later on be bought at the spot market at even lower prices. When the wholesale prices then turned out to increase rather than decrease, the prevailing selling prices were too low to cover the costs of power purchases and administrative costs. In other cases, the costs of the price and quantity risks assumed by the retailers were underestimated. On this point, a few words of explanation are needed.

The price risk in retailing stems from the fact that the relevant buying price is the area price while only the price risks associated with the system price can be hedged at a low cost at the financial markets operated by Nord Pool[24]. Moreover, as the Nord Pool prices are quoted in NOK (Norwegian kroner), there is also a currency risk for retailers in Sweden. The quantity risk stems from the fact that only the prices of fixed quantities can be hedged at Nord Pool, while customers are free to consume whatever quantity (within a certain limit) he/she likes to consume at the agreed prices. Not surprisingly, deviations between the expected and the actual consumption of the customers, i.e. "imbalances", served by a given retailer are common. As the retailers are financially responsible for the aggregate imbalances of their customers, the retailer has to buy or sell power at El-spot in order to balance these deviations. Currently, there is no market at which retailers can hedge these quantity risks.

Recently, the combined cost of the price and quantity risks discussed above have been estimated to be in the interval 0.9-6.8 EUR/MWh[25]. As the margin between selling and buying prices of

[24] As mentioned above, Nord Pool has recently opened a market for CFDs (contracts for differences) but so far, the liquidity in these instruments is rather low.
[25] The estimate is done by Svensk Energi (Swedish Energy) and reported in SOU (2002), p.119.

many retailers used to be around 2 EUR/MWh, part of the price increase should be ascribed to a more realistic view of the relevant costs of retailing. However, the price increase between 2001 and 2002 may also be related to structural changes on the retail market.

Traditionally, the major generating companies in Sweden have had rather small shares of the retail market. Thus, although Vattenfall has been the single biggest retailing company for a very long time, its share of the retail market was only around 15 per cent in the middle of the 1990s. However, in the last few years, the major generating companies, i.e. Vattenfall, Sydkraft and Fortum (formerly Birka) have bought majority or minority shares in a number of small and medium sized retailing companies. In general, the sellers have been towns and municipalities. Moreover, some of the independent retailing companies that entered the market in 1999, such as the Norwegian oil and gas company Statoil, have left the market.

As a result of these developments, the number of retailing companies has been reduced, and the "big three" have become dominating players of the retail market. For instance, if retailing companies where the "big three" own minority shares are included, Vattenfall is currently serving around 30 per cent of all customers, while the corresponding number for the "big three" is around 70 per cent. Similar numbers are likely to apply to the shares of electricity delivered to final consumers.

There are reasons to believe that considerable gains are to be made from mergers between retailing companies. Although the issue has not been studied in detail, a common view among industry representatives is that the efficient number of equally sized retailing companies is somewhere between 10 and 50. Thus, there is no reason to be concerned about the fact that retailing companies merge. What may be of some concern, however, is the fact that the mergers imply that the biggest companies grow, and that the increased concentration on the retail market is combined with an increased vertical integration between generation and retailing. In other words, why do independent retailers leave the market while integrated generation-retailing companies grow?

Although it is far to early to draw definite conclusions, it seems that the costs of hedging price and quantity risks are higher for independent suppliers than for vertically integrated generators-suppliers. Thus, while the independent suppliers are faced with high costs for price and quantity risks, the integrated generating-retailing companies can manage these risks on company-specific internal markets. In other words, while a period with very low temperatures may lead to unexpected costs for the retailing activity of an integrated power company, it also means unexpected profits for the generation activity. An independent retailer, on the other hand, only experiences the additional costs. These observations suggest that in the absence of organised markets at which independent retailers can hedge area price risks and quantity risks, there are economies of vertical integration between generation and retailing[26].

These economies of vertical integration are not a competition policy problem *per se*, but imply that the retailing market may be less competitive than anticipated. Thus, while entry on the retail market does not require significant investments, entrants without generating capacity seem to have a cost disadvantage in relation to the integrated generator-retailer incumbents. As entry to the generation segment of the market is very costly, it is likely that few potential entrants to the retail market can also enter the generation segment and become a new integrated generator-retailer. In view of these barriers to entry to the retail market, the increasing market share of the "big three" may in fact be a problem from a competition point of view, and active merger control seems to be a worthwhile activity.

4. Concluding remarks

The gains from increased competition on the electricity market are likely to be greater in the medium and long run than in the short run. But these gains will not be realised unless competition is maintained. In view of the barriers to entry both in generation and retailing, and the ongoing horizontal and vertical integration processes, the prospects for continuing efficient competition are not entirely positive. In other words, competition policy, in particular merger control, has a role to play. However, as the electricity supply industry is complex, there is also a role for sector-specific regulation aimed at directly or indirectly increasing efficiency via increased competition. Thus, by maintaining a certain slack in the inter-connectors between the Nordic countries, the TSOs can make significant contributions to a maintained competitive electricity market. Other sector-specific regulatory

[26] As is well known, the competitive effects of vertical integration are in general inconclusive. In this particular case, however, vertical integration does seem to have a clear impact on competition.

measures that may be worth considering include the redesign of "default contracts" and a more stringent regulation of retail distribution tariffs.

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