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The Norwegian Electricity Market

Is There Enough Generation Capacity Today and Will There Be Sufficient Capacity in Coming Years?

Statistisk sentralbyrå • Statistics Norway
Oslo–Kongsvinger

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Abstract

Tor Arnt Johnsen, Finn Roar Aune and Alexander Vik

The Norwegian Electricity Market
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Reports 2000/26 • Statistics Norway 2000

The Norwegian electricity market was restructured in 1991. Since then, gross domestic electricity demand has increased by 15 percent while generation capacity has increased about 5 percent. Low current and expected future prices have led to lower investment activity. However, imports of cheap power from Sweden and Denmark have kept prices low. Norwegian power generation is based on hydropower for which the inflow varies heavily from year to year. Demand is temperature dependent due to intensive use of electricity for space heating purposes. A tighter power balance and stochastic inflow and temperatures raise two important questions. First, to which extent is the market able to handle peak-load hours. Second, how will one or two subsequent dry years affect the market? Key factors to address these questions are the import possibilities, the availability and growth of domestic generation resources and the price flexibility in the demand side of the market. We sketch the underlying theoretical considerations and discuss the actual market design. We address the question whether the market design sufficiently stimulates profitable import, availability, investments and demand flexibility. We undertake various empirical exercises in order to decide whether today's situation makes reforms or other regulatory actions necessary. We examine some peak-load situations observed during 1998-2000, investigate the price flexibility and analyze the suppliers' operation and investment incentives. Finally, we evaluate policies able to resolve some of the detected problems.

Among such policies are design improvements as introduction of nodal price signals and removal of fixed changes that depend on installed capacity. In addition, we advise regulators not to allow regional mergers that leave regional markets with too few competitors. Finally, regulators should make it clear that public intervention not will be used to prevent high prices in periods with a tight power balance. Thus, traders, brokers and other middlemen face a high price risk if selling short, and have strong incentives to stimulate and maintain demand side flexibility.

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1. Introduction

The Norwegian electricity market was restructured in 1991. Electricity generation and supply were exposed to competition, and local and regional delivery rights disappeared. Transmission, distribution and system operation are regulated utilities. The restructuring of the Norwegian power sector has been successful. Regional and sectoral wholesale price differences are reduced, prices have been low (on average) and costly and non-profitable hydropower projects have been put on hold. Low actual and expected future prices explain the low investment activity. Electricity trade among the Nordic countries has increased and as Sweden and Finland have deregulated and joined a common market, we believe that electricity is provided in the cheapest possible way at a Nordic level. End-users are allowed to change supplier at no or a low cost and various contract types are used; fixed price, spot price based or mixed contracts.

Contrary to the low growth in Norwegian generation capacity, domestic power demand increases steadily and the domestic market becomes tighter as time goes by. In 1990, the yearly generation capacity was 107.5 TWh[1], while gross domestic power consumption was 105.6 TWh. In 1999, capacity had increased to 113.4 TWh and consumption was 120.4. Both 1990 and 1999 were wet years, actual generation was 121.6 TWh in 1990 and 122.4 TWh in 1999. In real terms, prices were about the same in 1990 as in 1999. These figures illustrate that the initial surplus is reduced over the ten-year period. However, imports of cheap power from Sweden and Denmark keep prices low. According to market information, future prices are expected to continue to be low for at least 3-5 years.

Norwegian power generation is based on hydropower for which the inflow varies heavily from year to year. The yearly inflow utilizable for production of electric energy varies from 85 to 138 TWh, while actual production varies from 105 to 130 TWh. Demand is temperature dependent due to intensive use of electricity for space heating purposes. The tighter power balance and stochastic inflow and temperatures raise a number of important questions:

- To which extent is the market able to handle peak-load hours? Is the current flexibility in demand and supply large enough to secure clearing of the day-ahead and regulation markets? If not, how can flexibility be provided in an efficient way?
- How will one or two subsequent dry years affect the Norwegian market? Is the market able to handle such a situation, and what will the realized prices, trade and demand figures look like during such a severely dry period?

Key factors to the answers to these questions are import possibilities, availability and growth of domestic generation resources and the price flexibility at the demand side of the market. Information is another crucial variable to these questions. Efficiency can only be achieved if the private cost of electricity consumption equals the social cost. However, it is costly to transmit price information. In Norway, large end-users are obliged to have hourly metering of their electricity consumption. Therefore, the potential for increased price flexibility may be significant.

Norwegian electricity consumption per capita and per GDP-unit is high, electricity prices are low compared to other countries and electricity is intensively used for space heating purposes. On this background, we expect a large potential for demand side flexibility in Norway. For instance, it may be relatively cheap to reduce demand in periods with high prices and tight supply compared to in other countries.

The rest of the paper is organized as follows. Some background on the deregulation design and the emerged markets are given in the next section. We also discuss the present rules for handling of shortages and examine some peak-load situations observed during 1999-2000. In section 3, we sketch the underlying theoretical considerations and discuss the actual market design and to which extent it stimulates profitable imports, availability, capacity expansions and demand flexibility. In section 4, we discuss some

[1] This refers to the generation capacity in a hydrologically normal year.

observed market imperfections and their consequences. In order to decide whether today's situation makes reforms or other regulatory actions necessary, we undertake various empirical exercises in section 5. We investigate the price flexibility and the incentives for price flexibility for several segments of the demand side of the market. In section 6, we take a look at the supply side of the market and its incentives to invest in new generation capacity. The power market's development path from 2000-2010 is simulated in section 7. To do this, we use the partial equilibrium model Normod-T under different assumptions. Section 8 contains conclusions and an evaluation of policies to resolve some of the detected problems.

2. Background

The Norwegian power generation is purely hydro-electric. Normally a power plant consists of a water reservoir, the power station with one or more turbines and one or more shafts that connect the reservoir and the power station. Water is collected from snow melting mainly in June, July and August and from rainfalls throughout the year, most intensive in September and October. The load is highest in the winter, November to April. Consequently, storage of water and the disposal of the water resources over time become seriously important decision variables for the power producers. The national reservoir capacity is 84 TWh or about 75 percent of the annual consumption.

Within the regulated regime there was a power pool named Samkjøringen. This pool was for generators only, thus excluding all end-users without own-production. In today's market there is a pool open for all market participants, Nord Pool. Nord Pool is the Nordic electricity exchange and is jointly owned by the Norwegian and Swedish main transmission grid owners and system operators (SO), Statnett and Svenska Kraftnät, respectively. Today, Nord Pool covers Norway, Sweden, Finland and the western part of Denmark and is still expanding its operational area.

The day-ahead market at Nord Pool, often quoted as the spot market, covered about 25 percent of the consumption in the area in 1999. The day-ahead prices are the most commonly used signal prices or reference prices of electricity in the region. In addition, they serve to give balance between planned production and planned consumption in all the regional markets. Nord Pool and other firms operate financial power markets where futures, forwards and options are traded. The true spot market is the real time or regulation market operated by the system operator, Statnett. In this market, deviations from planned (day-ahead) consumption and/or generation are traded. In order to improve the system's ability to meet shortage situations, Statnett has recently started to make contracts with large industrial consumers. According to these contracts, the consumer agrees to reduce demand for a certain time period if a shortage problem occurs. Statnett pays the consumer some amount of money in exchange for such an option. In addition a regulation market for market participants who do not meet the volume and flexibility requirements in the traditional regulation market is under consideration, this market is denoted the RK2 market.

2.1. Present Handling of Capacity and Energy Shortages in Norway

If the day-ahead market does not clear given the submitted bids, Nord Pool has the possibility of asking for new revised bids. If market equilibrium is still not achieved, Nord Pool undertakes a pro-rata reduction of all demand bids to clear the market. After this pro-rata reduction there will still be an expected unbalance in the market. This unbalance has to be handled by the system operator.

Statnett has as system operator a number of tools at their disposal. First, Statnett can interrupt all interruptible deliveries. Interruptible consumption pays lower grid charges than ordinary consumption does. Second, if Statnett expects a tight balance with low operating reserves, Statnett simply orders a number of generators to withhold a certain capacity from the day-ahead market and to bid this withheld capacity into the regulation market. Generators asked to withhold capacity are compensated by an amount per kWh equal to 25 percent of the actual day-ahead price.[2] Third, Statnett may order load curtailment[3]. Load is shed according to previously defined curtailment plans. These plans are based on repeated (rotating) shedding of smaller areas for an hour or two and not based on any evaluation of various group's value of lost load.

The winter 1996/97 was dry and national generation low. High day-ahead prices and thereby reduced exports, increased imports and reduced demand solved the problem. The dry year and high prices were high on the news agenda and NVE's director general public-

[2] This system of capacity reservation is now removed. It will be substituted with bilateral contracts on reserve availability.

[3] As of today Statnett does not have the authority to order interruption of other deliveries than interruptible consumption when faced with a short-term power shortage. Such an authority is currently under consideration.

ly advised lower electricity consumption. Tight energy balances may also be a regional phenomenon. During the 1990's, a severe tight power balance has been observed in a small area in the western part of Norway. This region has a weak radial connection to the rest of the system and therefore has to rely on local energy resources. Repeatedly, a very tight power balance has been observed towards the end of the winter (end of the storage season) and both NVE and Statnett have been very concerned about the situation. Various meetings and discussions with the market participants in the area have been undertaken to increase the imports and reduce the use of stored water in this region during the first and mid part of the winter season. Johnsen (2000) gives further details and some hypothetical explanations and proposes remedies.

2.2. Norwegian Experiences

Figure 2.1 shows the development of the yearly peak-load demand (actual and temperature corrected) and domestic generation capacity over the period 1980-2000. The generation capacity varies with the reservoir filling. Availability decreases as reservoirs are drained and is lowest at the end of the winter season.

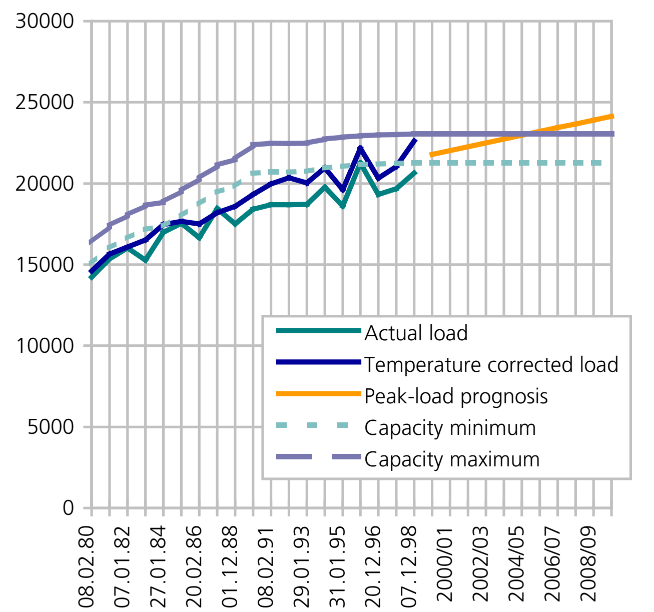
According to figure 2.1, the balance between supply and demand has become tighter towards year 2000. However, it is important to remember the presence of about 3500 MW import capacity.[4] Therefore, the balance is not as tight as the figure shows at first sight.

If peak-load demand growth continues towards 2010 as projected by Statnett (1999), and there are no investments in new generation capacity we may soon need imports during peak-load hours. However, a number of factors may modify this conclusion, see section 7.

Figure 2.1 says nothing about prices and foreign power trade during the peak-load hours. Prices are expected to say something about the degree of tightness, not only in Norway but in our neighboring countries as well. Trade figures may indicate to which extent there is some capacity available through reduced exports or increased imports. Figure 2.2 shows day-ahead prices and trade volumes for the same peak-load hours as in figure 2.1.

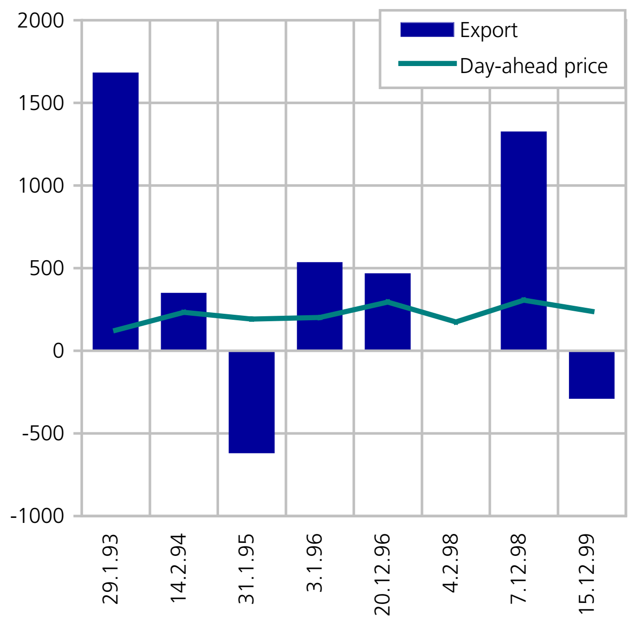
There are a number of interesting details in this figure. First, day-ahead prices have been below 310 NOK/MWh for all 8 annual peak-load hours. Nord Pool's maximum bid price until year 2000 (limited by their printed forms) is 2000 NOK/MWh.[5] Thus, it does not seem to have been a severe tight market balance during the 1990-ies. Second, in 6 out of 8 years Norway was a net exporter during peak-load. Only in 1995 and 2000 Norway imported power in the peak-load hour and the net imports these two years was 618 and 289 MW. With an aggregate import capacity of approximately 3500 MW, it seems to remain a potential for increased imports if day-ahead prices had been higher than they actually became.

Figure 2.1. Capacity and peak demand, 1980-2000. Projections for 2001-2010 based on Statnett (1999). MW



Source: Statnett.

Figure 2.2. Day-ahead price and net electricity exports for the yearly peak demand hours. MWh/h and NOK/MWh

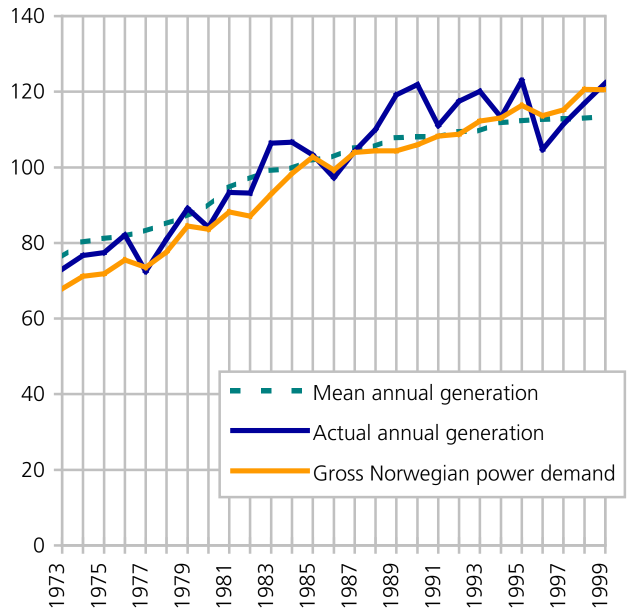


Source: Nord Pool and Statnett.

[4] The practical capacity towards Sweden is about 2500 MW and towards Denmark 1000 MW.

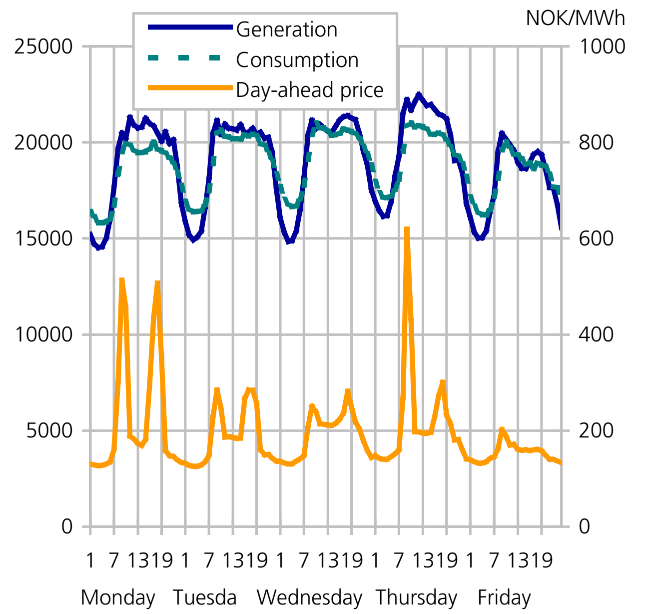
[5] From January 2000, the maximum price is 5000 NOK/MWh. 1 NOK is about 0.11 US$.

Figure 2.3. Gross demand, actual and mean year generation, 1973-1999. TWh



Source: Nord Pool and Statistics Norway.

Figure 2.4. Generation, consumption and day-ahead price in Norway during the weekdays of week 50, December 1999. MWh/h



Source: Nord Pool and Statnett.

Figure 2.3 shows the annual Norwegian mean and actual generation potential, gross domestic demand and average day-ahead power price during the period 1973-99. The figure illustrates reduced investment activity towards 1999 and a steady demand growth.

While gross demand at the beginning of the period was below mean year generation, the picture is different by the end of the period. However, Norwegian power prices are still low. Some explanation is found in the large flexibility of foreign power trade and huge amounts of cheap power available in Scandinavia and neighboring countries.

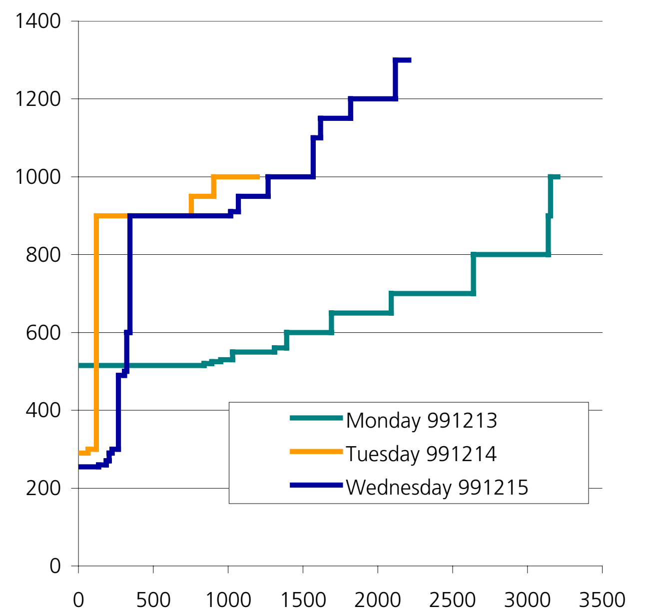
2.2.1. Some Observed Peaks during the Winter Season 1999/2000

December 1999

The third week of December 1999 was cold over the entire Nordic area and prices were above 400 NOK/MWh for six hours during this week, figure 2.4. Norway was split into three bidding areas but the actual number of hours with transmission bottlenecks was low and price differences were modest, see detailed figures for individual zones in appendix A1.

For all six peak-hours, Norway exported power to Sweden and Denmark. Generation reserves, measured as unused bids in the regulation market, varied between 240 and 2300 MW. Nearly all submitted regulation market resources were used in hour 9 at Tuesday when the up-regulation quantity was 806 MW resulting in only 240 MW unused bids this hour. The regulation price was 1000 NOK/MWh. Statnett

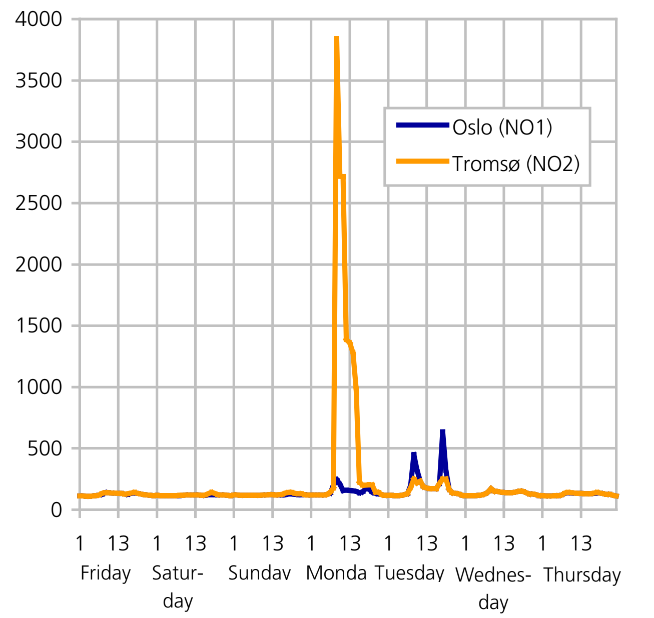
Figure 2.5. Bid curves in the regulation market hour 9 Monday 991213, Tuesday 991214 and Wednesday 991215. NOK/MWh



Source: Statnett.

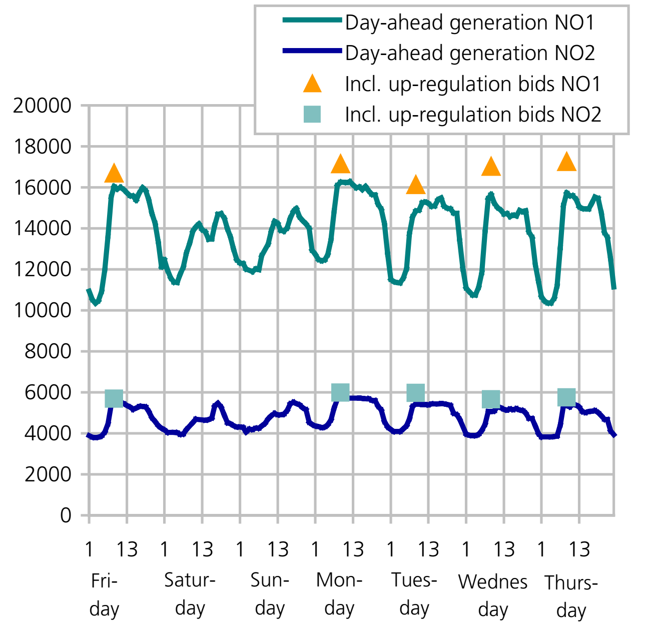
reserved capacity (500-550 MW) for hour 8-10 and 18-19 Monday, Wednesday and Thursday. Consequently, no capacity was reserved for Tuesday. According to figure 2.4, the quantity bid into the regulation market Tuesday was much lower than Monday. Aggregate regulation market bid curves at Monday, Tuesday and Wednesday are shown in figure 2.5.

Figure 2.6. Norwegian prices Friday January 21 - Thursday January 27 2000. NOK/MWh



Source: Nord Pool.

Figure 2.7. Planned, day-ahead generation and up-regulation bids Friday January 21 - Thursday January 27 2000. MW



Source: Nord Pool and Statnett.

January 2000

On Monday January 24th temperatures reached low levels throughout the Nordic area.[6] Statnett reserved 600 MW capacity and day-ahead prices were high. In hour 9, the price was 3840 NOK/MWh in northern Norway (NO2), Sweden, Finland and West-Denmark.[7] In southern Norway (NO1), the price stopped at 245 NOK/MWh and the transmission paths out of southern Norway were congested.

The situation changed remarkably from Monday to Tuesday. Still, Statnett reserved 600 MW capacity. For some hours Tuesday, northern Norway became a separate price area with lower prices than in the rest of the Nord Pool area. Southern Norway now joined the high price area to the benefit of generators in southern Norway.

Some explanation may be found in the planned, day-ahead generation figures reported in figure 2.7.

Planned, day-ahead generation is calculated as actual generation less actual regulation (up-regulation is a positive number, while down-regulation is a negative number). Planned generation decreased 1400 MW in the NO1 area from hour 9 Monday to hour 9 Tuesday despite a near doubling of the price. For hour 18 generation fell 800 MW, while the price rose 266 percent. Generation was also lower Tuesday than Monday in northern Norway. This is consistent with the much lower prices Tuesday. Even if up-regulation bids are included, figure 2.7 shows that around 1000 MW generation capacity disappeared from the markets on Tuesday.

The regulation market bid curve changed radically from Monday to Tuesday and Wednesday. The latter two days, suppliers submitted much higher prices than Monday.

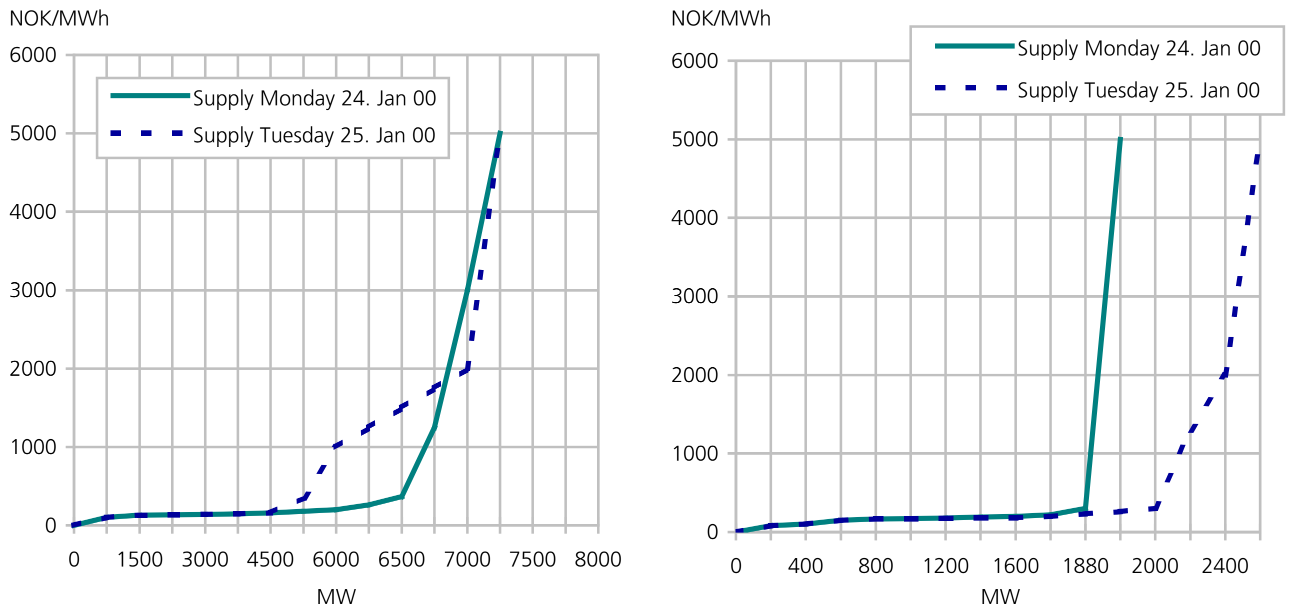
The change in day-ahead market supply curves is very clear. A rapid upward slope starts at a lower volume Tuesday than Monday. Total bid volume increased in the NO2 area, probably due to the very high prices observed Monday. In the NO1 area, total day-ahead bid volume is unchanged between Monday and Tuesday. It should be stressed that figure 2.8 gives supply and demand curves in the day-ahead market. These curves may both include demanders and suppliers since day-ahead market trade for many participants is only a "margin" market. Therefore, these curves should not be mixed with aggregate supply and demand curves.

Except for the volume and start-price differences, the bid curves for southern Norway (NO1) do not have very different shape. Monday has the steepest curve, while the bidders Tuesday provide near 500 MW at the day-ahead price level. The right panel contains bid curves for northern Norway (NO2). Monday is left out because of the very high start-price this day (3850 NOK/MWh). Friday and Wednesday have comparable shape but the volume is much larger Wednesday. Tuesday is different with a big jump at quantity 100 MW, when the bid price doubles.

[6] See Nord Pool (2000) for a description of the weather and operational conditions and an analysis of the incidents.

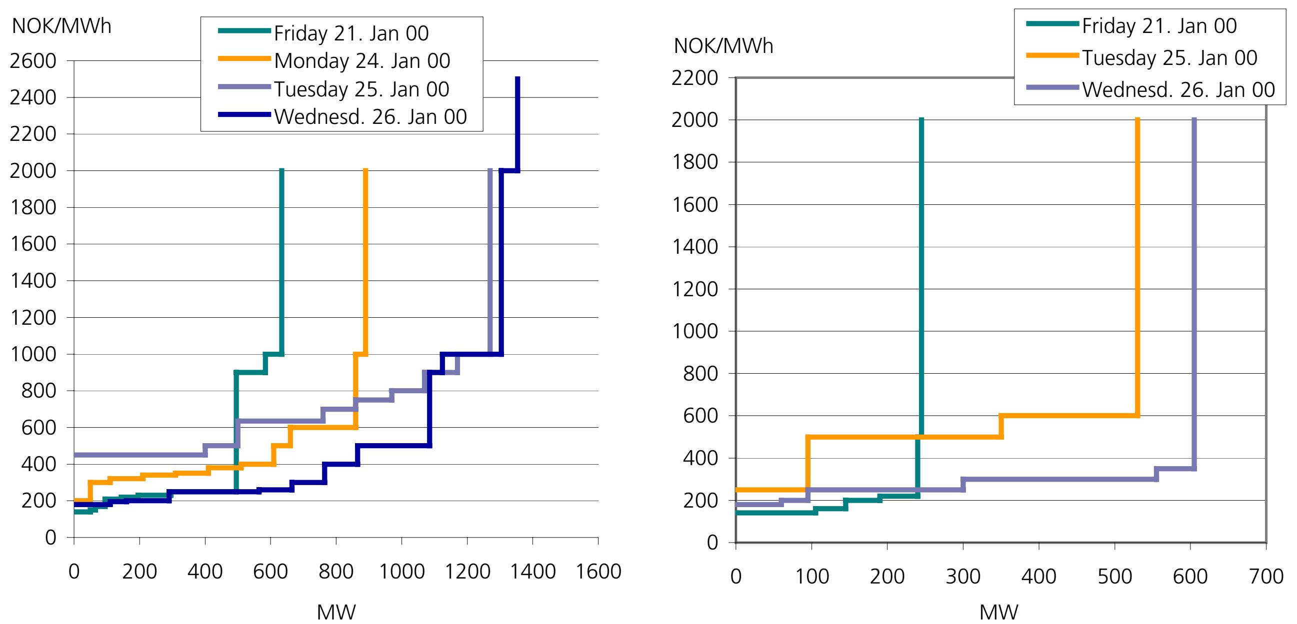
[7] Despite the high Nordic prices and much lower generation costs in Germany, exports from West-Denmark to Germany was not interrupted, see Bjørndalen (2000). This fact indicates that something was very wrong with the utilization of the Danish-German trade at this point in time.

Figure 2.8. Day-ahead market supply curves, Hour 9 Monday 24 and Tuesday 25 January 2000



Source: Nord Pool.

Figure 2.9. Regulation market bids (up-regulation) hour 9 Friday 21, Monday 24-Thursday 27 January 2000



Source: Statnett.

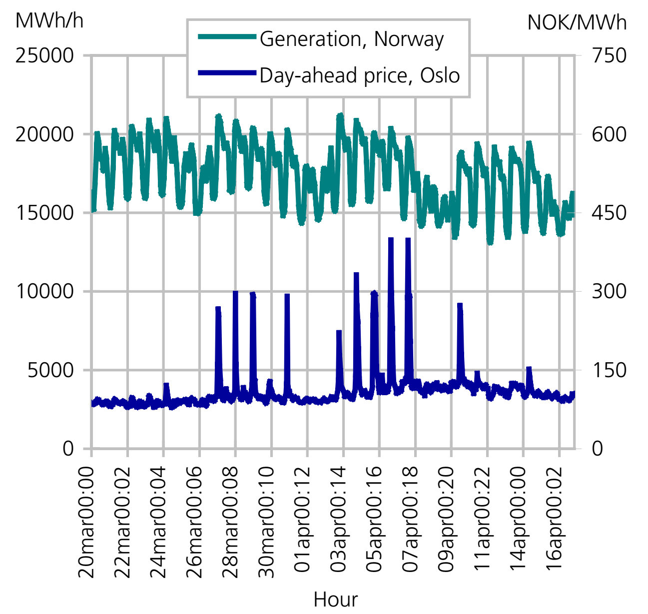
Figure 2.9 gives the bid-curves for the regulation market for hour 9 at the weekdays under considera-tion.

April 2000

Figure 2.10 shows the development of the day-ahead prices and generation in Norway during four weeks at the end of the winter season (March/April) 2000. Load was high for the time of the year and day-ahead price variations of 300 percent over a day were observed. This indicates that peak-load was close to the capacity limit and/or that there was some exertion of market power. Prices were even higher in Sweden and the export capacity to Sweden was often fully utilized. The high prices in Sweden may partly be a result of some thermal power outages in Sweden and Finland and some nuclear power revisions.

Figure 2.10 illustrates that peak-load situations accompanied by very high prices do not necessarily occur during the coldest and darkest time of the year as December and January.

Figure 2.10. Day-ahead price (left axis) and generation level (right axis). March 20 - April 16 2000



Source: Nord Pool.

2.3. International Experiences

Over the last 10-15 years, electricity markets worldwide are deregulated. Below we give a vague taste of the international experiences with regard to the markets' ability to handle peak-load situations. We do not undertake any in-depth analysis and interested readers should study the references in order to read more about each separate case.

2.3.1. England and Wales

England and Wales deregulated and privatized in 1989. Too few players at the supply side have led to strategic bidding in the mandatory English Pool. The market power problems may also have affected the success of the mechanism for capacity payments. In England the value of lost load (VOLL) and the loss of load probability (LOLP) are two central variables to the capacity payments. The regulator sets VOLL and it can not be said to be market based. LOLP is calculated from actual load and the amount of generator resources announced to be available during the actual half-hour. Generators are paid the product of VOLL and LOLP and these payments are financed by an uplift term on the Pool price. Wolak and Patrick (1997) find that generators withhold capacity in certain periods in order to increase LOLP and thereby the generator payments.

The Pool price is uniform for all generators and there is no regional variation in the Pool price. The missing signals about regional valuation of electric power is obvious and has caused most new generation investments to take place in the areas where the natural gas is landed. This may cause serious bottleneck problems in the transmission grid. Transmission prices are administratively determined and can hardly track market-based (efficient) transmission prices. The inefficient transmission pricing may well prevent efficient handling of peak-load situations since generation capacity not is established where it is demanded most but at places where the administrative transmission prices are most favorable.

2.3.2. Mid-West, USA

The Mid-western states of the US, experienced some very hot days during the summer 1998. The very high demand led to extremely high prices for the peak-load hours.

Various interests analyzed the situation, see for instance Enron (1998). They point to various explanations for the observed price spike and conclude that since peak capacity is very expensive, several huge price spikes should be expected within a market based electricity sector. Hirst and Hadley (1999) argue that price spikes will become more common within the deregulated market than within regulated markets. However, generators and consumers will learn to react to price movements and thereby reduce the need for minimum-installed-capacity requirements in the future.

2.3.3. California, USA

California deregulated during spring 1998. The new market was soon tested when the summer electricity consumption reached its all time high level. The core of the Californian system is day-ahead and hour-ahead power exchange ("PX-markets") and 6 different markets for ancillary services as spinning reserves, black start resources and so forth. The independent system operator (ISO) uses these "ISO-markets" to buy various operating reserves. During the summer 1998 prices reached extremely high levels in all the markets. Prices were consistent neither across markets nor compared to reasonable estimates of marginal costs. Market power and institutional flaws are most often mentioned as explanations for the inconsistencies. One institutional flaw was the very inflexible rules for determination of ISO's demand for the various reserve products. Two market-monitoring committees (PX and ISO) have provided excellent surveys and analyses of the happenings during 1998, see Bohn et al. (1999).

2.3.4. New England, USA

Cramton (2000) discusses the markets for reserve capacity in New England's power market. In addition to short-term markets for various reserves there is a monthly market for available capacity. Cramton concludes that the last market is redundant. In addition, he points to the ISO's vertical demand curve for reserves in each reserve market as non-optimal. Such a demand curve invites generators to exploit market power and it is doubtful that a vertical demand curve reflects the true marginal valuation of reserves for all prices.

3. Theoretical Considerations

Any countrywide electrical system is technically very complicated. Electricity can not be stored and immediate balance between supply and demand is essential. Generators and consumers are connected through a network of grid lines in which laws of physics det ermine the flows. In general, decisions by one market participant have implications for a large number of other participants and the system as a whole. Within the limits of this report, we do not intend to describe the complexity of the system. We try only, in very simple ways, to sketch some elements of the theory of price determination and quantity allocation within a competitive electricity market. First, we study optimal prices in a situation with an exogenous security margin and optional rationing of customers with fixed price (and variable quantity) contracts. We then take a look at rationing costs and market based rationing.

3.1. Efficient Pricing

The following discussion is based on section 9.2 in Schweppe et al. (1988). We define

g	Generation of electricity
$C(g)$	Cost function for electricity generation, $C' > 0$
g^{crit}	Critical generation level. Limits actual generation due to system security. Determined by system operator
d^S	Electricity demand, spot price customers
d^P	Electricity demand, predetermined "price-only" rate customers. Price fixed for the time period considered, quantity variable
$B^i(d^i)$	Benefit from electricity consumers in group i, $i = S,P$, $B^{i\prime} > 0$
$\overline{d}^P$	Actual consumption level for predetermined rate consumers after rationing. If no rationing $\overline{d}^P = d^P$
$R(d^P - \overline{d}^P)$	Rationing cost, $R' > 0$, $R(0) = 0$

The total cost is

(1) $$TC = C(g) - B^S(d^S) - B^P(d^P) + R(d^P - \overline{d}^P)$$

and the following constraints apply

$d^S + \overline{d}^P = g$	Market equilibrium, demand = supply	Shadow price λ
$g \le g^{crit}$	Security constrained dispatch	Shadow price γ
$d^P - \overline{d}^P \ge 0$	Positive or no rationing	Shadow price μ

In order to minimize costs given the constraints, we form the Lagrangian

(2) $$L = C(g) - B^S(d^S) - B^P(d^P) + R(d^P - \overline{d}^P) + \lambda(d^S + \overline{d}^P - g) + \gamma(g - g^{crit}) - \mu(d^P - \overline{d}^P)$$

Differentiation of (2) yields

(3) $C' + \gamma = \lambda$	Marginal generation cost + Shadow price of capacity/security = Shadow (market equilibrium) price of electricity (Spot price of electricity)
(4) $B^{S\prime} = \lambda$	Marginal benefit spot price customers = Spot price
(5) $B^{P\prime} = R' - \mu$	Marginal benefit predetemined price customers = Marginal rationing cost - Shadow price of positive rationing
(6) $R' - \mu = \lambda$	Marginal rationing cost - Shadow price of positive rationing = Spot price

If there is no rationing, μ is non-zero and μ is zero if there is rationing. Equation (4) to (6) say that the marginal benefit of electric power should be equal for the two groups of customers and equal to the marginal generation cost. Equation (3) states that marginal benefit in an optimal situation is equal to the production cost including the shadow price of reserve capacity.

Equation (3) to (6) raise at least two important questions. First, how to determine the shadow price of capacity/security. Second, how to estimate the rationing cost.

The English system with an hourly pool price adder equal to the loss of load probability (LOLP) times the value of lost load (VOLL) is one example of det er-mination of the shadow price of capacity/security. The English experience is not impressive, generators seem to withhold capacity in order to increase LOLP and the importance of the magnitude of VOLL may not be fully recognized, see the discussion in Cramton (2000) and Wolak and Patrick (1997).

As stated in Schweppe op cit., within the above model, the marginal rationing cost is a ceiling for the spot price of electricity. This is seen from equation (6), which in case of rationing simply says that the marginal rationing cost should be equal to the spot price of electricity. While spot price customers face the actual spot price and voluntary reduce their consumption when price becomes high, predetermined price-only consumers should be rationed in accordance with their individual marginal rationing cost. However, in practice rationing often takes place as rotating black-outs, quota regulations or according to a priority list in order of increasing rationing cost. In the case of rotating blackouts, the rationing cost should be equal to the average cost of reducing demand or providing more energy. This cost may be estimated from

- Costs of load management equipment and its use
- Allocation of annualized cost of peaking plant

When the spot price reaches the estimated cost, rationing should be started.

It should be stressed that rationing is a last resort for the system operator. In market based systems, prices should increase when there is a shortage and the market should be designed in such a way that short-term prices gives incentives to suppliers of price-only contracts to establish mechanisms for load reductions when spot prices reach certain levels.

While customers with hourly load metering and spot price contracts represent little problems, customers with fixed price contracts or without hourly metering do not have strong enough incentives to reduce load in shortage situations. However, their suppliers will indeed have strong incentives to avoid periods with extreme prices and heavy financial losses. Network owners may be in a comparable situation. Bottlenecks in a local grid may cause very high costs to the network owner and he has a strong incentive to establish systems that allow load reductions in periods with heavy load or other network capacity problems. Given these incentives there is room for interruptible contracts and direct load control. Both allow some load reductions in critical periods. Whether the critical constraint originates from the network or generation system is of little interest. The main point is the incentives created by variable and in periods very high, spot prices. These incentives highly motivate establishment of a variety of contracts between suppliers and customers. We believe such contracts to increase demand flexibility and to realize efficient market solutions. We discuss incentives and technologies available for direct load in section 5.

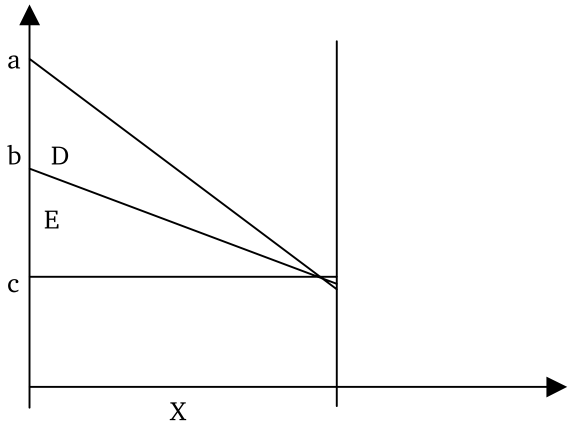
3.2. The Cost of Rationing and Market Based Rationing Methods

In the absence of transaction costs and other market imperfections, electricity spot markets are an efficient way to allocate the produced quantity of electricity between different consumers, i.e. the outcome under perfect competition. Due to the laws of physics, the production and consumption quantity of electricity must be equal at every point of time. Obsessive monitoring and transaction costs for most consumers obstruct a (near) perfect competitive solution. In reality, most consumers face a price of electricity, which does not fluctuate from hour to hour. The market clearing relies on a system operator who has control over some electricity production (and some consumption decreases) reserves to equalize discrepancies between the consumption and production in real time. In extreme situations, with very high consumption levels or other situations with insufficient system resources, market clearing is impossible. Under the existing regime, the system operator has no choice but to stop deliveries of electricity to alternating groups of electricity consumers or reduce delivery to groups of consumers, regardless of their valuation of the loss of electricity. These rationing methods are called rotating blackouts and quotas, respectively. These methods imply a cost that is described below. An alternative is to use some kind of market mechanism to discriminate between consumers such that the use of rotating blackouts or quotas is avoided.

3.2.1. Costs of Rationing

In a situation with rotating blackouts, the cost of imperfect rationing is described graphically in the figure below. Assume we have two consumer groups and that the electricity price in equilibrium is c. Both groups have equal consumption X. Now a situation where rotating blackouts is necessary occur. During two periods each of the consumer groups experience loss of all power deliveries once. The value of the lost consumption are the sum of the areas (D+E) and E. With market rationing, the consumer group with loss valuation E is decoupled from electricity consumption twice, with a total loss of E+E. In other words, the loss with rotating black-outs compared to market rationing is the area D. A similar cost occurs with quotas, since different consumers will have different valuations of their consumption reduction.

Graphical illustration of the loss with rotating black-outs



In theory it is possible to estimate the cost of rationing with rotating blackouts compared to market rationing. Combining information of the value of involuntary loss of load for the different consumer groups and information on how often rotating blackouts occur in relevant sub markets, may give a rough cost estimate. Kvitastein and Singh (1991a, b, c) reports the value of lost load for different consumer groups in Norway, and may be a starting point for further research.

3.2.2. Marked Based Rationing Methods

Market based rationing methods are in theory superior to administrative rationing with rotating blackouts or quotas. A market-based system on the other hand may have large structural costs. In order to conclude which system that has the lowest costs in practice, information about monitoring and transaction costs in a market based rationing regime is needed. Furthermore, several market based rationing methods are described in the literature, none of which is superior under all circumstances. Bernard and Roland (2000) describes a system with self-rationing as an alternative to regular service is offered to the consumer. Self-rationing implies that the consumer chooses a level of maximum power use. Higher consumption, if desired, is not possible. In Wilson (1989) priority services rationing, which implies that (some) consumers are self-selected into classes which are differentiated by service priority and electricity price, is described. Consumers are served according to their chosen class until the capacity limit is eventually reached. A striking feature of this method is that few classes are enough to capture most of the efficiency gain. Spulber (1992) describes a scheme called pro-rated services where consumers choose a baseload consumption level. This serves as a basis to determine payment and allocation under different circumstances.

3.2.3. Rationing in Practice

In practice rationing in Norway will take form of either administratively allocated quotas or rotating blackouts. In both cases rationing will be the result of a political decision and will therefore only be applicable to long- or medium-term shortages such as in a dry year. It is also clear from the discussion above that none of these methods will give an efficient outcome. This is because the consumers' valuation of lost load is not taken fully into consideration, neither when the quotas are decided nor when the blackout areas and frequencies are selected. The advantages of these methods are that they are administratively feasible and that they may be viewed as socially acceptable since all consumers must give an effort to resolve the shortage situation.

4. Market Imperfections

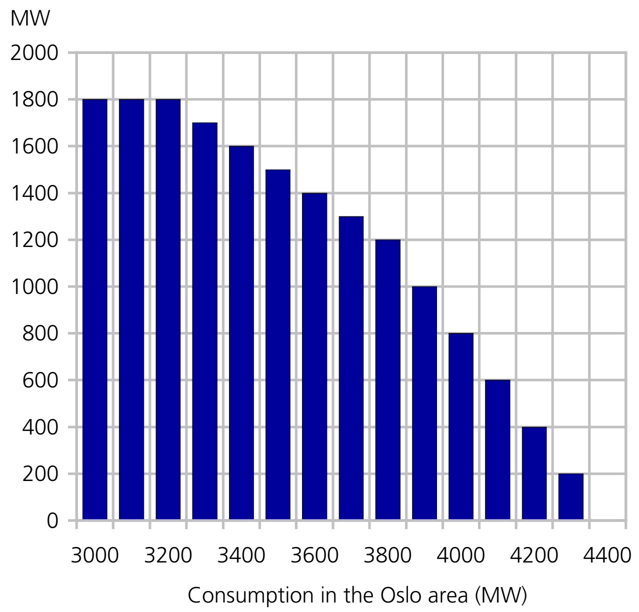
In this section we discuss market imperfections which have consequences for the efficient allocation of power in the Norwegian electricity market.

4.1. Handling of network congestion – the zonal pricing drawback

Statnett designates price areas or zones for which bids into the day-ahead market are to be given. Intra-zonal congestion is normally removed by "special regulation" or out of merit order generation in the regulation market. In addition, Statnett seems to use the transmission capacities between certain zones to avoid congestion problems in other parts of the grid.

One obvious example is the so-called "Hasle stair". Hasle is name of an important network interconnection between Norway and Sweden in southeastern Norway. In normal operation, the thermal capacity of this link is 1800 MW. However, when power consumption in the Oslo area at the Norwegian end of the interconnection exceeds 3200 MW, Statnett reduces the export capacity of the interconnection. According to Statnett, this is done to avoid congestion in the grid between western and southern Norway and the Oslo area. Figure 4.1 illustrates the capacity available in the day-ahead market for power transmission from southern Norway (Oslo area) to Sweden for various levels of the demand in the Oslo area.

Figure 4.1. Net transmission capacity from southern Norway to Sweden (Hasle stair)



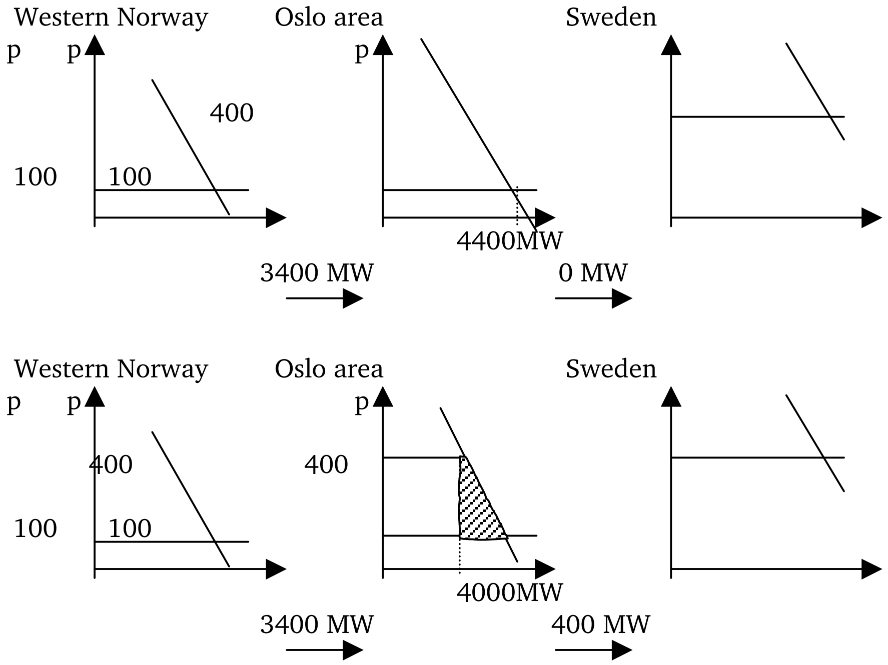
Source: Statnett

Swedish import and demand in Oslo contribute equally to the congestion between western Norway and Oslo. This is not reflected in prices since when the internal Norwegian path is congested Statnett reduces the export capacity to Sweden and the Swedish price becomes higher than the Norwegian (Oslo area) price. Consumers and producers in the Oslo area see too low prices, while Swedish prices may be too high. The social loss depends on elasticities and may be substantial. Figure 4.2 illustrates the social loss and the transfers between producers, consumers and Statnett following this imperfect pricing and transmission regime.

For simplicity, we assume in figure 4.2 that the price in Sweden is fixed at 400 NOK/MWh and independent of the import from Norway. In Oslo, generators produce 1000 MW irrespective of the actual price. In the upper part of the figure, transmission capacity to Sweden is set to 0 in order to avoid congestion between western Norway and Oslo. The transmission from western Norway to Oslo is 3400 MW, equal to the network capacity.

In the lower part of the figure, transmission capacity to Sweden is set to 1800 MW and the Oslo area becomes a part of a Swedish-Norwegian price area with a price equal to 400 NOK/MWh. The transmission from western Norway is unchanged and so is the price in western Norway. The 300 percent price increase in the Oslo area is assumed to release 400 MW in reduced consumption (price elasticity -0.03). The social gain from efficient pricing is 60000 NOK per hour (shaded area). Generators in the Oslo area gain 300000 NOK per hour, while Statnetts merchandizing surplus (bottleneck income) increases from 0 to 1.02 mill. NOK per hour. Consumer surplus in the Oslo area is reduced by 1.26 mill. NOK per hour.

Figure 4.2. Numerical illustration of the "Hasle stair" social loss and income transfers



This simple example shows that the amounts of money involved soon become large and the importance of getting the prices right is obvious. Various authors give important arguments for electricity prices that reflect the underlying physical characteristics of the network (locational marginal prices), see for instance Hogan (1998) and Ruff (1999)

4.2. Imperfect Network Regulations - Pricing and Income Regulation

Network regulations and pricing policies have important effects on demand for power withdrawal. In this section two imperfections in the network regulations and their impacts on efficiency are discussed.

4.2.1. Regional cost variations within a network, nodal congestion

Inside a network, it will always be the case that the degree of free capacity in withdrawal nodes will differ. This will be the case in the central grid as well as in the regional and distributional networks. While some nodes may have plenty of free withdrawal capacity, others are near or at the capacity limit. Since the marginal cost of withdrawal from a node will depend heavily on the degree of congestion in the node, this means that the marginal cost of withdrawal will differ between nodes, with the cost increasing in the degree of congestion. This is not taken into account in today's pricing system since the price for withdrawal always has to be the same in every node within each network. This means that the scarcity of capacity will not be fully reflected in the price of withdrawal in congested nodes. It also means that the incentives for power withdrawal reductions for end-users within a network will be independent of the degree of congestion in the node they withdraw their power from. This is quite unfortunate from an efficiency point of view since end-users who withdraw from congested nodes are the ones that first and foremost should be given incentives to reduce their power withdrawal.

4.2.2. Interaction among network owners

There are two main ways to increase available transmission capacity; through inducing the end-users to reduce their power withdrawal and by upgrading the network components. To ensure efficiency, such an increase in the available transmission capacity should be undertaken in the least expensive way. This will not necessarily be the case in the Norwegian power system. In many cases the bottleneck will be at a different network level than the end-users. This means that an investment in power reducing installations at the end-user level will have its cost at the distributional network level and its gain at for example the regional network level. If it turns out that reducing end-users' power withdrawal is cheaper than upgrading the congested regional network components, efficiency requires that this alternative be realized. If the distributional network invests in equipment for reducing its end-users' power withdrawal it will be given the right to increase its income from its customers since its invested capital will have increased. However it may experience a reduction in its rate of return on capital since it has increased its capital and reduced power withdrawal in its network, thereby reducing its efficiency. Since a network's allowed return on capital depends on efficiency measures, this could reduce allowed rate of return on capital. In theory it will be possible for the owner of the regional network to pay for the investment at the distributional level and to reach an agreement with the distributional network owner to transfer part of the distributional network's income rights to the regional network. However, since such an income transfer never can increase the total income of the two networks, whether this will be profitable for the regional network will depend on the relative efficiency of the two network areas. If the allowed return on capital is lower in the distributional network it may be the case that even though an increase in available capacity is cheaper through investment in power withdrawal reducing equipment, upgrading the regional network will be preferable for the owner. This may happen because the allowed return on capital is greater in the regional network, thereby making the least efficient investment alternative the most profitable one. If one adds that transferring income between networks is a cumbersome affair, this will increase the probability of investments in capacity increases in the regional network at the expense of investment in power withdrawal reducing equipment. All in all this will lead to investments being biased towards investments in network upgrades, leading towards higher power withdrawal than efficient in the system.

5. Price flexibility in the demand side

The degree of short-term price flexibility in demand is essential for the handling of power shortage. There are many different types of end-users in the Norwegian electricity market each with different properties and incentives for price-flexibility. In the following the demand side will be split into three main groups, non hourly-metered, hourly-metered, and interruptible consumption. First we look at these groups' incentives for price flexibility, then we undertake several empirical exercises to investigate the degree of price flexibility among the different groups.

5.1. The Demand Side Agents

5.1.1. Non Hourly-Metered Consumption

- Most end-users with annual electricity consumption of less than 400 000 kWh
- Do not have hourly metering, actual load profile is therefore unknown
- Customers' meters are usually read four times per year if yearly consumption is above 8000 kWh, once a year if electricity consumption is lower than this
- The supplier of such customers is charged with the customer's share of AWP (Adjusted Withdrawal Profile) in the period between each time the meter is read (profiling)
- Each end-user is too small to influence the AWP
- A large share of the group is not charged for power withdrawal in their transmission charge
- Roughly 50% of all electricity consumption in Norway do not have hourly metering[8]

AWP for a distributing network area is found in the following way; all production inside the network area and net withdrawal from adjacent networks are summed and we get total consumption. Then hourly-metered consumption and expected network losses are subtracted and we receive an estimate of non-hourly-metered electricity consumption for every hour of the day. The network operator then calculates each customer's share of AWP based on previous years' electricity consumption. In Statnett's weekly supplier settlement a supplier of a non-hourly-metered end-user is charged with the sum of its customers' share of AWP. Since each user's actual consumption to some degree will differ from its expected consumption, an implicit settlement is performed each time the customer's meter is read. In this settlement the supplier is charged for the difference between the customer's actual consumption and his expected consumption as measured by his share of the network's AWP for the period. The price used in this settlement is the price in the spot market Elspot for the period weighed by the AWP. This implicit settlement is then added to an account for the supplier, and this account is settled annually.

This means that a rational supplier who offers a spot price contract will offer a contract where the price is the price in Elspot weighed by the AWP for each period between meter readings plus some mark-up. The weighed spot price is given by

$$p = \frac{\sum_{t=1}^{T} p_{s,t} b_t}{T} \qquad \text{where} \qquad b_t = \frac{AWP_t}{\sum_{t=1}^{T} AWP_t}$$

p is the weighed-average price in the period between each meter reading, T is the number of hours in the period, $p_{s,t}$ is the price in the spot market in hour t and AWP_t is the AWP in hour t. This means that the price to the end-user is $p+\tau$, where τ is the mark-up over the weighed-average spot price. Since each customer is too small to influence b, the rational behavior for the end-user is to adjust his electricity consumption to expected $p+\tau$ in each period. This means that changes in the spot prices only will influence the behavior of the end-user if the price change reflects changes in the expected period price. Since the period is usually one

[8] According to Statistical yearbook 1999 agriculture and households are responsible for approximately 34% of the electricity consumption in Norway, power-intensive and wood-processing industries 35%, mining and other industries 9%, transport and communications 1,5% and other commercial uses 20,5%. If one assumes that electricity consumption in all power-intensive and wood-processing industries, all mining and other industries, all transport and communications and 25% of other commercial uses are hourly-metered, then roughly 50% of all electricity consumption will be hourly-metered.

quarter of a year, there are approximately 2200 hours in each period, and consequently each hour's contribution to the period price will be almost negligible. A sudden price increase in an hour due to an expected power shortage in the system would therefore not influence the expected average price, unless the price increase is perceived as a sign of higher spot market prices in the future. This means that not even customers with spot price contracts will have strong incentives to adjust their electricity consumption to short run price variations in the spot market prices, and hence no rational short term price flexibility can be expected from this part of the market.

Since the Norwegian electricity production is almost exclusively based on hydropower, the annual production capacity varies greatly with meteorological conditions. In a dry year inflow can be 25% below normal. Such an energy shortage will give higher prices both in the spot market and in the futures and bilateral contracts market. For non-hourly-metered end-users that have spot price contracts this means that the expected period price will rise. In addition the contract price in new fixed price contracts will be higher. This means that all end-users except those with long-term fixed price contracts that do not expire in the duration of the dry year have an incentive to adjust their electricity consumption. In Vik (2000) the elasticity of electricity consumption with regards to the electricity price excluding transmission costs and taxes is estimated to be in the vicinity of -0,1 to -0,2 when the end-users are given one month to adjust to the new prices[9]. This roughly says that a 50% increase in the electricity price, excluding transmission costs and taxes, implies a 5% to 10% reduction in electricity consumption.

5.1.2. Hourly-Metered Consumption

- End-users with yearly electricity consumption above 400 000 kWh and a few smaller customers
- Have hourly metering thus actual load profile is known
- The supplier of such customers is charged with the end-user's actual load profile
- The transmission charge for such customers usually include a power charge
- Roughly 50% of all electricity consumption in Norway is hourly-metered, of this about 70% belongs to either power-intensive or wood-processing industries

End-users in power-intensive and wood-processing industries cover their consumption by own production, bilateral fixed volume contracts, and purchases in the day-ahead- and RK-markets. Since their actual load profile is known and their contracts are of the fixed-volume type, their alternative cost of one more planned unit of electricity used is the day-ahead price. This also applies to hourly-metered end-users with spot price contracts; since their actual load profile is known they will be charged with the day-ahead price plus a mark-up. This means that sufficiently high prices in the day-ahead market should induce both these groups to reduce their electricity consumption.

Other hourly-metered end-users usually have contracts without fixed volume. For those customers with fixed price contracts this means that they have no incentives to adjust their electricity consumption to changes in the day-ahead market prices.

As noted above a dry year will give higher prices both in the spot market and in the futures and bilateral contracts market. For hourly-metered end-users that have spot price contracts and end-users in power intensive or wood-processing industries this means that their electricity price will rise. In addition the contract price in new fixed price contracts will be higher. This means that all end-users except those with long-term fixed price contracts that do not expire in the duration of the dry year have an incentive to adjust their electricity consumption to the new higher prices.

5.1.3. Interruptible Consumption

- Have hourly metering thus actual load profile is known
- The supplier of such customers is charged with the end-user's actual load profile

Interruptible consumption is electricity consumption which on a two or twelve hour notice, depending on the contract between the end-user and the network owner, may be disconnected by the network owner. These end-users always have hourly metering since this is the only way to ensure that they actually disconnect their electricity consumption when ordered to do so. Interruptible consumption is mostly boilers which on short notice can switch from electricity to oil, in addition interruptible contracts are often used in the agricultural sector for lighting purposes in greenhouses. Most end users with interruptible contracts have spot price contracts, where the contract price is the day-ahead price plus some mark-up, and are therefore affected by price fluctuations in the day-ahead market. Still they may not have much incentive to adjust their consumption to the actual day-ahead price from hour to hour. As is shown in appendix A2 there is little incentive with the price variations in today's market to actively adjust to the day-ahead price from hour-to-hour, since this will have a cost in time spent gathering and analyzing information. Instead they may plan their consumption based on expected spot-market prices, such as the futures price for the following week. As table 5.1 shows, interruptible withdrawal is of a considerable size in peak load even when

[9] This could be overestimated since income measures are left out of the estimation due to data problems.

Table 5.1. Interruptible withdrawal and day-ahead prices in peak load 1998-2000

	Total interruptible withdrawal in the peak load hour		Day-ahead price in the peak load hour
Year	Norway[1]	Southern Norway	Southern Norway
1998	864,4 MW	664,6 MW	194,87 NOK/MWh
1999	564,3 MW	407,2 MW	158,29 NOK/MWh
2000	757,8 MW	573,0 MW	619,85 NOK/MWh

[1] This is the sum of interruptible withdrawal in peak load in southern, central and northern Norway. Since the peak load hour in the different areas may be at different times, the interruptible withdrawal in the maximal load hour for the country as a whole may differ from this.

the day-ahead prices are high, as in the peak load hour of 2000. Thus interruptible consumption will most probably be a significant reserve in a constrained situation as it can be disconnected if necessary.

5.1.3. Who Is Exposed to High Prices and Who Is Not?

Non-hourly-metered end-users and hourly-metered end-users with fixed prices are not affected by short-term high prices in the day-ahead market. In the case of hourly-metered end-users with fixed prices their supplier is exposed to the high prices, since the supplier is charged with the end-users actual consumption in each hour. This means that there is some incentive for the supplier to make its customer reduce its consumption in hours with high prices. In the case of non-hourly-metered end-users there may be no such incentive, this may arise for two reasons. The first is when end-users have spot price contracts. Since the supplier is charged with the day-ahead price weighed with the AWP for the period and it charges its customer with the day-ahead price weighed with the AWP for the period plus some mark-up, the supplier is not exposed to the high prices. Since each customer is too small to affect the AWP and that high prices in a few hours does not increase their period prices by much, they are not greatly exposed to high short term prices either. The high price is then spread out over the whole period and all end-users, making it negligible for all. The second case is when there are many suppliers each with small shares of the market. If all customers have fixed-price contracts and no supplier has more than, say 10 percent of the market, then no one will have an incentive to reduce or induce reduction in consumption in response to short term increases in the day-ahead prices. Since their contract price is fixed the customers will have no incentive to reduce their electricity consumption. Since the end-users actual profile is unknown, the suppliers are charged with their customers expected share of the AWP. This means that if a supplier by some means convinces his customers to reduce their consumption in hours with high prices, the gain from this will be split among all the suppliers in the area according to their customer's share of the AWP. As a consequence suppliers with a relatively small market share in an area will have little or no incentive to make an effort to convince their customers to reduce their consumption in hours with high prices.

To sum up: End-users in power intensive or wood-processing industries, interruptible consumption end-users, and hourly-metered end-users with spot price contracts have incentives to adjust to both short term and long term increases in prices in the day-ahead market, although they may adjust their consumption to the expected Elspot prices rather than the actual day-ahead price. The suppliers of hourly-metered end-users with fixed price, free volume contracts have an incentive to induce their customers to reduce their electricity consumption if there are sufficient long- or short-term increases in the day-ahead prices. Non-hourly-metered end-users with spot price contracts will have an incentive to adjust to long-term increases in the day-ahead prices but not to short term increases. End-users with fixed-price free-volume contracts will not have incentives to adjust to price changes unless these influence the contract prices in the market and they enter a new contract during the period. Suppliers of non-hourly-metered end-users with fixed price contracts will only have an incentive to induce its customers to adjust to increases in the day-ahead prices if their market share in the area is large.

5.2. Demand Side Price Flexibility. Empirical Results

5.2.1. Price Elasticities for Electricity. International Experience

As can be seen from table 5.2, the estimates of residential electricity price elasticities found in the literature show large variation. The results vary for several reasons. First, the variation may be due to different types of models. Second, even though the models are similar, the observable and unobservable characteristics of the households may vary across countries.

In the last decade there has been a trend towards using disaggregated data to model household electricity consumption. Improved computer capacity has made this possible. There is a lot of individual variation in household energy consumption, and accordingly estimates of elasticities should be based on micro data. However, there may be an aggregation problem when micro estimates are to be used on the household sector. The considerable variation in estimates of electricity price elasticities makes it difficult to find the best estimate of this elasticity. More analyses are needed to find a good estimate of the impact on electricity consumption when the electricity price changes.

Table 5.2 . Estimates of income and price elasticities for residential electricity consumption in the literature[1]

Reference	Income elasticity	Electricity price elasticity
Micro studies:		
Halvorsen, B. and B. Larsen (2000). Norway. Dynamic model. Data for 1976-93	0.13	-0.43
Nesbakken (2000). Norway. Total energy space heating. Data for 1990	0.06	-0.21
Nesbakken (1999). Norway. Total energy for all purposes. Short run results. Data for 1993-95	0.01	-0.50
Halvorsen, B. and R. Nesbakken (2000). Norway. Short run results. Data for 1993-94	0.04	-0.76
Parti, M. and C. Parti (1980). USA. Short run results	0.15	-0.58
Morss, M.F. and J.L. Small (1989). USA. Short run results. Long run: Income elasticity 0.18, price elasticity app. -0.4	0.08	-0.23
Baker, P., R. Blundell and J. Micklewright (1989). United Kingdom.	0.17	-0.76
Dennerlein, R.K.H. (1987). Germany. Discrete-continuous choice model (electrical appliances)	0.42	-0.38
Dubin, J.A. and D.L. McFadden (1984). USA. Average demand (electricity and gas). Discrete-continuous choice model (heating equipment)	0.02	-0.26
Bernard, J.T., D. Bolduc and D. Bélanger (1996). Canada. Discrete-continuous choice model (heating equipment). Short run results from IV-method	0.14	-0.67
Branch, E.R. (1993). USA. Short run results	0.23	-0.20
Garbacz, C. (1983). USA. Short run results.	0.10	-0.19
Macro models:		
Skjerpen, T. (2000). Norway Long run results. Input in MODAG today	1.03	-0.31
Short run results. Input in MODAG today	0.30	-033
Aasness, J. and B. Holtsmark (1993). Norway. Long run results	0.28	-0.20
Strømsheim Wold (1998). Norway. Long run results. Input in MSG-6 today	0.40	-0.24

[1] These are price elasticities with regards to the price paid by the end-user.

5.2.2. Increased Price Flexibility by Time-of-Use (TOU) Tariffs. International Experiences

By giving the customers sufficient incentives, it is possible to make them shift their load from peak to lower load periods. There are many examples of this internationally, here we will look at three examples. For a survey of Norwegian and international experiences with TOU tariffs, see Grønli (1997).

Finland's third peak

In Finland many household customers have tariffs where the price of electricity is high during the day and then falls substantially after 9 PM. The idea behind this is to stimulate the consumers to shift some of their load from day to evening/night. This has been so successful that the Finnish grid experiences a third peak period, this peak is right after the households tariffs go from the high to the low price period. The reason is that the customers postpone some of their load, such as washers and dryers, until the low price period.

A similar result is known from the Manweb area in the UK. An area known as Aberystwyth experienced a new peak load at 1 AM due to a low price period starting at this time. In this case, the peak was so large that the tariff structure had to be changed to reduce it.

The French Tempo tariff

In France a tariff known as the Tempo tariff is available for all end users. It is a tariff where the year is divided into three types of days, red, white and blue, and each day into a high- and low-load period, giving six different price periods. There are 22 red, 43 white and 300 blue days. The electricity price differs among the periods, and is almost 10 times higher in high load on red days (18 hours) than high load on blue days. Prices are generally 1,5 - 2,5 times higher in the day than in the night. The type of day is decided the day before. A signal is then sent to each user, where a color code on a display on each meter tells the customer what type of day the next day will be. The red days, days where load is expected to be high, are generally cold days since electricity for space heating is quite common in France. The tariff has been quite successful and customers actually use less electricity on red than blue or white days, despite the fact that red days generally are colder. This reduction stems both from customers switching from electricity to oil-fired space heating and from a general substitution in the use of electric appliances from high-price to low-price periods. For a more detailed description of the tariff and the experiences with it, see Augin et al. (1995)

5.2.3. Modeling Aggregate Hourly Electricity Demand in Norway

Previous studies using hourly electricity consumption data explain short-term consumption variations with physical conditions as temperatures, day-length and a number of dummies or spline functions that explain daily and weekly demand movements, see for instance Harvey and Koopman (1993) and Engle et al. (1986). These analyses are carried out for regulated electricity markets in which short-term consumer price movements are not present.

The main purpose of this section is to estimate a short-term price elasticity of hourly electricity demand. While temperature, day-length and other physical conditions may still be important explanatory variables, we have added various variables indicating short-term price movements. As discussed above, customers with hourly metering of consumption and customers with contracts with prices linked to the actual day-ahead price movements may have an incentive to adjust consumption to short-term price movements. Estimated elasticities should be expected to be low just because more than 50 percent of the consumption has no incentive to reduce consumption when prices are high. We have data on 8 regions within Norway and model aggregate demand in each region.

In our estimated models, we measure prices in three different ways:

- For each hour under consideration, we include the actual and the 24 hours lagged day-ahead price. In addition, we allow the price response to depend on whether it is day or night.
- We assume consumers to make daily consumption adjustments. Day-ahead prices are known at least 10 hours before the actual hour occurs. (The day-ahead market clears at 2 PM for the hours 1 AM - 12 PM on the following day.) Thus, we use the daily average of the hourly day-ahead price and one day lagged average price. Still, we allow day/night variation in the price response.
- Instead of the actual mean of the day-ahead price, we use the previous Friday's futures price for the day under consideration. For instance, the consumption during Tuesday is explained with the futures price for Tuesday traded the previous Friday. Here as well, we allow day/night variation in the price response. Lagged price is not included since Friday's price is known at least 3 days before the actual consumption day.

Day-ahead prices are determined as the prices that lead to equilibrium between predicted consumption and planned generation, where both consumption and generation are price dependent. Deviations from planned consumption and generation are settled at the regulation-market price. Bids to this market are submitted two hours ahead. The realized regulation price is, however, not known before consumption and generation actually take place.

One obvious problem connected with estimations of price elasticities is the potential simultaneity problem. High demand leads to high price and low demand to low price. We estimate on consumption data for 8 regions within Norway, while prices in most cases are determined on a national or Nordic basis. For each separate region, it may be reasonable to take the day-ahead price as exogenous. However, in periods with transmission constraints that isolate a smaller part of the market, the simultaneity problem may be important. In addition, electricity consumption in regions in Norway along the Swedish border may be influenced by weather conditions closely correlated with Swedish weather conditions. In such cases, the simultaneity problem may cause severe problems.
In order to cope with the simultaneity problem, we estimate demand and price simultaneously using Full Information Maximum Likelihood method (FIML).[10] In addition to the demand function, we include a price (or supply) function. To identify the true demand function we need variables in the supply equation that shift the supply curve in the short-run. Such variables are hard to find. Water availability and snow volumes vary over time but it is hard to quantify when such information reaches the market participants. We ended up with a price equation in which price depends on aggregate Norwegian-Swedish power generation and the futures price of power for delivery the first week after the end of our estimation period. Finally, we included one term indicating the difference between actual average daily day-ahead price and the previous Friday's futures price for this same day. The last variable was lagged 24 hours.

To sum up, our four estimated models are:

Model 0

$$\begin{aligned}&log(d_t) = const + dummies + \\ &\alpha_0\, log(p_t) + \beta_0 D_t\, log(p_t) + \delta_0\, log(p_{t-24}) + \\ &\mu_0 D_t\, log(p_{t-24}) + \gamma_0 \tau_t + \eta_0 dl_t + \lambda_0 C_t + \varepsilon_t\end{aligned}$$

Model 1

$$\begin{aligned}&log(d_t) = const + dummies + \\ &\alpha_1\, log(\overline{p}_t) + \beta_1 D_t\, log(\overline{p}_t) + \delta_1\, log(\overline{p}_{t-24}) + \\ &\mu_1 D_t\, log(\overline{p}_{t-24}) + \gamma_1 \tau_t + \eta_1 dl_t + \lambda_1 C_t + \varepsilon_t\end{aligned}$$

Model 2

$$\begin{aligned}&log(d_t) = const + dummies + \\ &\alpha_2\, log(f_t) + \beta_2 D_t\, log(f_t) + \gamma_2 \tau_t + \eta_2 dl_t + \lambda_2 C_t + \varepsilon_t\end{aligned}$$

Model 3

$$\begin{aligned}&log(d_t) = const + dummies + \\ &\alpha_3\, log(p_t) + \beta_3 D_t\, log(p_t) + \delta_3\, log(p_{t-24}) + \\ &\mu_3 D_t\, log(p_{t-24}) + \gamma_3 \tau_t + \eta_3 dl_t + \lambda_3 C_t + \varepsilon_t\end{aligned}$$

and

$$\begin{aligned}&log(p_t) = const + \nu_3\, log(x_t) + \kappa_3\, log(\overline{x}_t) + \\ &\pi_3\, log(F_t) + \omega_3\, log(\overline{p}_t / f_t) + \eta_t\end{aligned},$$

where the symbols are

[10] We have used the interactive program Troll, see Hollinger and Spivakovsky (1993).

d_t end-use demand hour t
p_t day-ahead power price
τ_t temperature in degrees Celsius
dl_t day-length, 1 if sun has risen, 0 else
C_t dummy equal to 1 on Christmas days
$\bar{p}_t$ daily average of the day-ahead price
f_t futures price for the actual day determined previous Friday
x_t power generation in the region under consideration
$\bar{x}_t$ aggregate Norwegian-Swedish power generation
F_t Futures price for the week after the end of the estimation period determined at time t
ε, η white-noise residuals

Other Greek letters are parameters to be estimated. The variable "*dummies*" include one dummy for each hour, each day, or (168-1) dummies. Parameters on dummies are restricted to be the same for Tuesday, Wednesday and Thursday. Consequently, the number of dummies is reduced to (120-1).

Data
We apply hourly data for the period, 29Nov99Hour1 - 16Apr00Hour23 for the 8 Norwegian regions. Statnett has kindly provided the generation and consumption data.

One region (region 5) is left out because of measurement errors in the original data, due to a very low consumption in this region compared to this regions generation. Day-ahead prices were determined for not more than 3 regions during any of the hours within our estimation period. Regions 1, 2, 4, 5 and 6 had always the same price, denoted p_1, region 3 had price p_3, while region 7 and 8 had common price, p_8, in all hours.

Table 5.3 shows the correlation matrix for the generation, consumption and price variables.

The correlation matrix shows a number of interesting facts. First, the correlation between demand and generation is low for many of the Norwegian regions underlining the importance of interregional trade. Export and import out of and to the regions makes the simultaneity problems less than expected. Another reason for this low correlation may be heterogeneity across regions with respect to reservoir capacity and the volume of run of river hydroelectric plants. Second, for all regions the correlation between Norwegian regional demand and Swedish aggregate generation (x_S) is larger than the correlation between each region's demand and generation. If the Swedish generation level determines day-ahead prices this correlation may disturb our estimation of the price elasticity in model 0-2. This correlation is highest for region 6, which is located nearest the Swedish market. Third, prices are positively correlated with demand and generation in all Norwegian regions indicating the problems of estimating only a single demand equation without taking the supply curve into account.

We downloaded day-ahead prices and futures prices from Nord Pool's ftp-server.
Temperatures and day-length are collected for 8 locations around Norway. Each location is chosen to represent the consumption midpoint of the region. The Norwegian Meteorological Institute provided temperature observations for 7 AM, 1 PM and 7 PM. Between these points in time we have used a linear interpolation. Data for day-length are constructed using information found at the following web site http://aa.usno.navy.mil/AA/data/docs/RS_OneYear.html.

Table 5.3. Correlation matrix for consumption, generation and price in Norwegian and Swedish generation

	d_2	d_3	d_4	d_6	d_7	d_8	x_1	x_2	x_3	x_4	x_5	x_6	x_7	x_8	p_1	p_3	p_8	x_S
d_1	0.701	0.721	0.752	0.834	0.721	0.764	0.265	0.682	0.670	0.554	0.673	0.693	0.724	0.682	0.442	0.442	0.235	0.839
d_2	1.000	0.735	0.742	0.827	0.745	0.637	0.362	0.760	0.587	0.404	0.563	0.724	0.622	0.629	0.490	0.488	0.244	0.828
d_3		1.000	0.717	0.706	0.737	0.715	0.054	0.550	0.750	0.641	0.766	0.638	0.722	0.708	0.354	0.355	0.191	0.804
d_4			1.000	0.748	0.712	0.759	0.198	0.616	0.669	0.612	0.696	0.684	0.690	0.700	0.360	0.361	0.169	0.824
d_6				1.000	0.732	0.693	0.374	0.755	0.569	0.392	0.547	0.767	0.655	0.678	0.553	0.550	0.248	0.841
d_7					1.000	0.748	0.219	0.688	0.673	0.520	0.672	0.688	0.716	0.694	0.413	0.413	0.187	0.820
d_8						1.000	0.234	0.585	0.621	0.542	0.666	0.673	0.628	0.697	0.339	0.340	0.197	0.776
x_1							1.000	0.506	-0.092	-0.404	-0.109	0.571	-0.111	-0.016	0.218	0.217	0.109	0.352
x_2								1.000	0.462	0.188	0.403	0.735	0.516	0.467	0.439	0.438	0.192	0.727
x_3									1.000	0.738	0.686	0.429	0.749	0.642	0.292	0.293	0.146	0.651
x_4										1.000	0.728	0.193	0.775	0.673	0.114	0.118	0.098	0.477
x_5											1.000	0.539	0.727	0.699	0.192	0.196	0.142	0.717
x_6												1.000	0.426	0.556	0.376	0.377	0.171	0.843
x_7													1.000	0.710	0.380	0.382	0.201	0.687
x_8														1.000	0.306	0.304	0.173	0.732
p_1															1.000	0.999	0.390	0.459
p_3																1.000	0.390	0.460
p_8																	1.000	0.237
x_S																		1.000

Results
Estimation results are mixed. For model 0,1 and 3 we were not able to establish estimates that consistently pointed to negative price elasticities of reasonable magnitude. However, single regions and price variables show significant parameter estimates. Estimated coefficients and standard deviations for all the price terms in all models are given in appendix A3, table A1. Here, we focus on the results from model 2 which included futures prices for each day determined the previous Friday as price variable. For 4 out of 7 regions we end up with very promising results, see table 5.4.

Table 5.4. Estimation results, model 2, region 1, 3, 4 and 8

	Estimated price elasticity		R-squared
Region	Day	Night	
1	-0.03	-0.06	0.44
3	-0.06	-0.05	0.75
4		-0.04	0.66
8	-0.07	-0.04	0.68

The regions included in the table covers about 60 percent of the Norwegian power demand. Night elasticities are stable in the area -0.04 to -0.06, while estimated day elasticities vary more. It is not clear whether the elasticity is largest during night or day. An elasticity of -0.04 indicates that if price increase with 100 percent consumption falls with 4 percent. We use aggregate consumption within the region and on average only 50 percent of the customers have hourly metering of electricity consumption. A number of these customers may have fixed-price contracts and thereby no incentive to reduce consumption when prices increase. Thus, for customers that adjust to prices, elasticities are larger than by first sight. Since we apply futures prices determined Friday as price measure for the coming week, the interpretation of the elasticities is not a price flexibility hour by hour. Instead, it is the consumer response in a given hour to futures prices announced some days earlier. One important question is then to which extent the daily futures prices are able to absorb a shortage situation that may only last for some hours. This question and in general the lack of consistent estimates across regions call for more research in this field.

5.2.4. Short-term price flexibility in interruptible consumption

To investigate the degree of short-term price flexibility in interruptible consumption empirically, data for interruptible withdrawal from 12 different network areas in the county of Buskerud were gathered for the period November 1999 to March 2000. Prices in the day-ahead market, temperature observations and figures for hours of daylight were also collected. To control for the inter-weekly electricity consumption pattern, each hour of the week was given a dummy variable. Letting the first hour of Monday be the numeràire, this gives 167 dummy variables. Since the consumption pattern is likely to be similar for Tuesday, Wednesday and Thursday these days were given common dummies, reducing the number of dummies to 119. In addition a dummy variable taking on the value one in the Christmas holiday and zero else was added to control for the effect of the Christmas holiday.

Preliminary estimations showed, consistent with the findings above and those reported in appendix A2, that interruptible consumption depended on expected Elspot price rather than the actual hourly Elspot price, although large deviations between expected and realized Elspot prices seemed to have some effect[11]. The estimations also indicated that expected Elspot prices below 120 NOK/MWh seemed to have no effect on interruptible consumption. Sluggish adjustment and decreasing effect of temperature lead to the following linear demand function:

$$x_t = a_0 + \sum_{i=1}^{119} a_i D_{it} + b_1 C_t + \sum_{j=1}^{3} d_j P_{jt} + \sum_{k=1}^{4} e_k T_{kt} + f x_{t-1}$$

Where the following symbols are used:

x_t is interruptible electricity consumption at hour t

D_{it} is the value of dummy variable i at hour t

C_t is a dummy variable taking on the value one in the Christmas holiday and zero elsewhere

P_{1t} is zero if the expected Elspot price for the day, expectation as of Friday the week before, is lower than 120 NOK/MWh and min{30, P_t - 120} if not, where P_t is the Eltermin price, Friday the week before, for the day which hour t belongs to.

P_{2t} is zero if $P_t < 150$ and { P_t -150} if $P_t > 150$

P_{3t} is zero if the actual Elspot price for hour t, P_t^S, minus the expected Elspot price for the day, P_t, is less than 50 NOK/MWh and { $P_t^S - P_t$ } if $P_t^S - P_t > 50$ NOK/MWh

T_{1t} is a temperature variable which is min{12, T_t }, where T_t is a temperature variable taking the value 15-T_t^{obs}, where T_t^{obs}, is the observed outside temperature in degrees Celsius for hour t[12], when $T_t^{obs} < 15$ and zero if $T_t^{obs} > 15$

[11] For each day of the week the Futures price for that day set Friday the week before was used as a measure of expected Elspot price.

[12] Since the temperature was only observed at 1 AM, 7 AM, 1 PM and 7 PM each day the temperature observations for the hours between each actual observation were constructed by linear interpolation.

T_{2t} is a temperature variable which is min{6, T_t -12}, when $T_t > 12$ and zero if $T_t < 12$

T_{3t} is a temperature variable which is min{7, T_t -18}, when $T_t > 18$ and zero if $T_t < 18$

T_{4t} is a temperature variable which is T_t -25, when $T_t > 25$ and zero if $T_t < 25$

and where the a's, b's, d's, e's and f are parameters to be estimated.

The main results using OLS are given in table 5.5.

Table 5.5 Main results from estimation using OLS

Observations	2640	
R-squared	0.94	
Durbin-Watson	1.80	
Parameter	Estimate	T-stat
d_1	-0.034	-4.7
d_2	-0.045	-2.3
d_3	-0.004	2.0
e_1	0.090	1.7
e_2	0.098	3.5
e_3	0.066	1.7
e_4	-0.018	-0.1
f	0.904	101.3

As is shown in table 5.5 all estimates except e_4 are significant at a 10% level of significance. The estimate for e_4 is, with a t-value of -0.1, not significantly different from zero at any reasonable level of significance. The results in table 5.5 yield short-term own-price elasticities of about -0.07 to -0.09 varying with price and consumption. It also shows that shocks in the form of large deviations from the expected price gives a significant reduction in consumption. It also shows that effect of temperature is decreasing indicating constraints on the end-users' electric heating capacity. It is also clear that there is a great degree of sluggishness in demand, with the estimate of f being 0.904. This indicates long-term own-price elasticities of about -0.7 to -0.9, taking roughly 36 hours to reach[13].

The estimation shows that interruptible consumption is quite price-flexible but that the relevant price for the agents is the expected Elspot price rather than the actual spot price. Although large differences between actual and expected Elspot price seem to have some effect on interruptible withdrawal, this seems to be with a lag. This can explain situations such as in the peak load hour in 2000 where the area price for Oslo in Elspot rose to 619.85 NOK/MWh without causing large reductions in interruptible withdrawal. All in all this indicates that interruptible withdrawal can be a significant reserve in a constrained situations.

5.2.5. Short-Term Price Flexibility in non Hourly-Metered Electricity Consumption

The short-term demand for non hourly-metered electricity consumption is investigated in Vik (2000). In the following a short summary of the main results will be given.

The AWP from three distributional network areas in the county of Buskerud from the period 1997 to 1999 were used to estimate a log-linear demand function on daily, weekly and monthly data. In the preliminary estimations the demand was estimated using both prices in Elspot, standard contract prices to households in the distributional area, prices of heating oil, measures of outside temperature, hours of daylight and lagged non hourly-metered electricity consumption. Due to data problems measures of income were left out of the estimation giving somewhat biased estimators. It became clear from the preliminary regressions that the Elspot prices did not influence electricity consumption, and Elspot prices were therefore left out of later regressions. In the end the following regression was estimated

$$ln(AWP_t) = a_0 + a_1 ln(B_{Tt}) + a_2(ln(B_{Tt}) - ln(B_{Tt-1})) + a_3 ln(P_{Et}) + a_4 ln(P_{Ot}) + a_5 ln(B_{Dt}) + a_6 D_{Dt} + a_7 ln(AWP_{t-1}) + a_8 D_{Ft} + \varepsilon_t$$

Where subscript t indicates period t, AWP_t is the non hourly-metered electricity consumption in period t, P_{Et} is the price of electricity measured by the standard contract price, included transmission costs and taxes, offered to the households in period t, B_{Tt} is a measure of temperature in period t, P_{ot} is the price of heating oil delivered in period t, B_{Dt} is the average number of hours with daylight per day in period t, D_{Dt} is a dummy variable which takes on the value one in week-ends and public holidays and zero elsewhere, and D_{Ft} is a dummy variable which takes on the value one during summer vacation (three first weeks of July) and zero elsewhere.

The main results from the estimations were:

- Non hourly metered electricity consumption does not seem to be influenced by fluctuations in the prices in Elspot
- Elasticities with regards to the standard contract prices, excluding transmission costs and taxes, were estimated to -0.1 to -0.2 when consumption was given time to adjust to the new prices[14]

[13] Long-term in the sense that the sluggishness in short term demand are taken into account, not in the sense that the agents are given time to make changes in their stock of appliances in response to permanently new price levels. The elasticities are with regards to the Eltermin prices for the day set Friday the week before, not including transmission costs and taxes.

[14] This could be overestimated due to the exclusion of income measures

This indicates that a permanently higher price level in Elspot will give lower electricity consumption through higher contract prices while short term fluctuations in the Elspot prices will leave electricity consumption unchanged among non hourly-metered end-users.

5.3. New technology to increase demand flexibility

There are various products available which make it possible to reduce individual end-user's or entire network area's power withdrawal. These products can in general be divided into two groups; products where the network owner has the possibility to directly reduce load, and products where the customer himself programs a unit to disconnect certain electrical apparatus whenever either the customer's power withdrawal or the electricity price exceeds a certain level.

Some network areas in Norway either have installed or are planning to install systems for direct load control. This is possible by installing remote-controlled switches on circuits controlling sluggish heating installations, such as water heaters, combined with electronic meters and two-way communication. This is the same system that is in use in some network areas to disconnect interruptible consumption. If we assume that each household's water heater on average is active 2/3 of the time in the hours between 7:00 AM and 10:00 AM a disconnection of these circuits in this period will give a power reduction of roughly 2 kW per customer. The potential reduction per customer is likely to be much greater for industrial customers and housing complexes.

Elvippa and El.kontroll are examples of products where the customer on their own can program a unit to disconnect certain electrical installations when either the customer's power withdrawal or the electricity price exceeds a certain level. Since the savings potential is mainly in power withdrawal reduction and substituting electricity consumption between periods with high and low prices, this means that only customers with time-varying tariffs or customers which are charged for their power withdrawal have an incentive to invest in such systems.

6. Generation capacity expansion incentives and costs

Statnett employs *access charges* to create incomes, which is necessary to fulfil the regulated income requirement. Both input and withdrawal of power are due to access charges. There are two different types of access charges

First, there is an *admission fee* per MW. The volume (MW) is given by winter production capacity (generators) or peak load demand (for parties that withdraw power). The fees are the same for all nodes, but the fee for withdrawal is about 10 percent higher than for input.

Second, there is a *power charge* per MW based on *net volumes exchanged* in the specific node. For a node where the input is greater than the withdrawal in peak load, the volume is calculated as:

	Input in the peak period
-	Withdrawal in the peak period
+	Idle generation capacity in the peak period
+	Interruptible consumption, electric boilers

In a node with net withdrawal, the volume is given by

	Withdrawal in the peak period
-	Input in the peak period
-	Idle generation capacity in the peak period
-	Interruptible consumption, electric boilers

The charge is 25 percent higher for a node with net withdrawal than for an input node. Finally, there is from 1999 introduced a charge for reactive withdrawal. Table 6.1 summarizes the access charges applied in 1998.

Table 6.1. Access charges in 1999

	Admission fee	Power charge
	NOK/MW	NOK/MW
Generators	12000	
Consumers	13000	
Input node		46000
Node with net withdrawal		57500
Reactive withdrawal, NOK/MVAr		20000

The access charges do not affect the short-term decisions except for peak-shifting at the consumer side. However, we assume this to be of limited importance.

In the long-term, however, access charges affect the profitability of investments in new generation capacity. Transmission charges levied on the installed capacity (NOK/MW) have implications for the choice between generation technologies, locations and project designs:

- Planned hydropower projects in Norway have an annual operating time of 2500-3500 hours, while for instance a combined cycle gas plant is expected to operate for 7500-8000 hours. The access charge increases the per kWh cost of hydropower with about 6 percent while the gas power cost only increases with 3 percent. Consequently, investments are biased towards gas and other base load thermal technologies. In general, peak technologies become too expensive compared to base load technologies since the access charge for peak load technologies is divided on a small number of operating hours.
- Access charges bias the order of the development of new hydropower sites. Hydropower projects, which require high turbine capacity and which are located in areas with surplus supply (high access charges), will be delayed relative to other hydropower projects. The zonal or nodal power price gives the correct signal, while the cost added by the access charge results in an inefficient capacity expansion pattern.
- For a new hydropower project the access charge disturbs the design-choice between turbine capacity and reservoir/inflow capacity. The access charge adds a cost to turbine capacity expansion and makes turbine capacity relatively more expensive than energy capacity. Investments in additional turbine capacity in existing power plants become too low since the access charge makes such investments less profitable.

Investments in turbine capacity
Several physical constraints may lead to price differences between day and night within a hydropower system. A single producer that treats the prices as

exogenous tries to produce as much as possible in the high price periods (daytime) and as little as possible during periods when prices are low (nights and weekends). One possible limitation on the ability to move production to the high-price periods is the turbine capacity. For a generator who faces a binding turbine capacity constraint, an increase in the turbine capacity allows movement of generation from night to daytime. The marginal benefit equals the price difference or the shadow price of turbine capacity.[15] The cost of increased turbine capacity for a new or rebuilt plant depends on the construction cost of increased turbine capacity and the *transmission charges related to installed capacity*. In order to decide whether to invest or not, the generator has to develop expectations about future prices over the lifetime of the investment.

An example
The investment decision can be illustrated within a simple example. We consider an investment that increases the turbine capacity from K0 to K1. The investment allows an energy quantity of $(K1- K0)H_{Dt}$ to be moved from night to daytime production, where H_{Dt} is the number of daytime hours. The annual benefit associated with an increase in the turbine capacity from K0 to K1 is

$$\Delta = \sum_{t=1}^{T}(PDt - PNt)(K1 - K0)H_{Dt}$$

We assume the turbine capacity constraint to be binding in the winter only (30 weeks). In addition, we assume the number of daytime hours per week to be 80 and the average price difference to be equal to 20 NOK/MWh. The annual benefit raised by a 1 MW increase in the turbine capacity turns in this case out to be

$$\Delta = 20NOK/MWH * 1MW * 30weeks * 80hours/week$$

An official estimate of the annualized cost of turbine capacity is an average of 150000 NOK/MW for capacity additions totaling to 1500 MW. In addition comes the transmission access charges, the admission charge of 12000 NOK/MW and the power charge ranging from 0 to 46000 NOK/MW dependent on the net exchange in the node under consideration. This example illustrates

- Given the assumptions, investments in turbine capacity are not profitable.
- The fixed transmission charges accounts for 7 to 28 percent of the total annualized cost related to an expansion of the turbine capacity.

Table 6.2. Average price differences between day and night that support investment in turbine capacity, NOK/MWh

	Annualized investment cost		
	100000 NOK/MW	150000 NOK/MW	200000 NOK/MW
Transmission charge:			
58000 NOK/MW/year	66	87	108
12000 NOK/MW/year	47	68	88
0 NOK/MW/year	42	63	83

The above example can be turned around to find out how large the day/night price difference has to be to make an investment profitable. Such a calculation is illustrated in table 6.2.

Table 6.2 shows that price differences around 70 NOK/MWh has to be realized over the lifetime of the investment to make additional turbine investments profitable. Here, we have assumed increased turbine capacity to be valuable in 30 weeks per year. Seasonal considerations and a positive value of turbine capacity also in the summer may lead to increased profitability of turbine investments.

Efficiency loss
Fixed cost recovery transmission charges levied on installed capacity will reduce the profitability of new power plant investments, in particular investments in turbine capacity. Both will create losses. Figure 6.1 illustrates the daily efficiency loss induced by too low turbine capacity.

In figure 6.1, we have drawn the day demand curve (DD) from left to right and the night demand curve (DN) from right to the left. The length of the bottom line of the figure equals the sum of night and day generation (XD+XN). With a turbine capacity equal to K0, the realized prices are PDt and PNt. In a competitive market this price difference will equal the cost of increasing the turbine capacity plus the transmission access charge. If we remove the access charge, the generators would have expanded the turbine capacity to K1 reducing the price difference between day and night periods to the expansion cost alone. The black area represents the efficiency loss induced by the access charge.

The price differences between day and night observed in the Norwegian market are currently not large enough to make new turbine investments profitable irrespective of the magnitude of access charges. Therefore, the efficiency loss discussed above is a *potential future loss*. Figure 6.2 shows the hourly movement of the day-ahead price in Oslo for January 1998.

[15] We assume here that no other constraints become binding as the turbine capacity is increased.

Figure 6.1. Illustration of the efficiency loss when the turbine capacity is too low

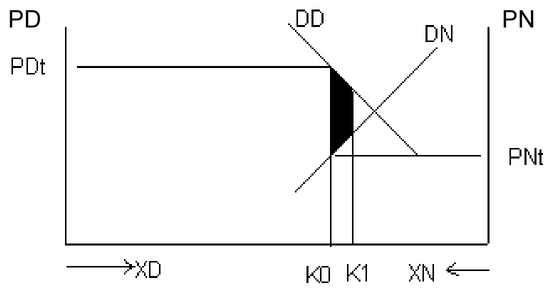
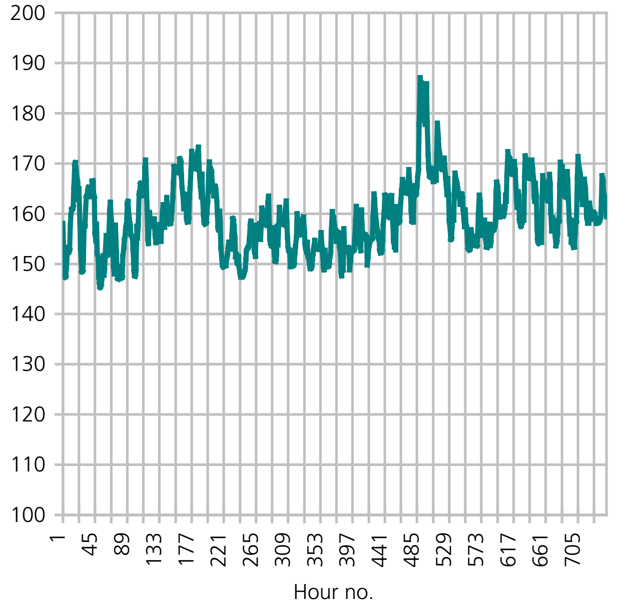


Figure 6.2. The net hourly day-ahead price in Oslo, January 1998, NOK/MWh[1]



[1] In order to construct the relevant net prices, we have reduced the day-ahead prices with 1 percent for night/weekends and 4 percent for weekdays. This is done to represent the marginal loss transmission charge. The levels of the loss percents are not important, it is only the difference between night/weekend and weekday that matters

Source: Nord Pool

The price variation is about 20 NOK/MWh over the day, less in the weekends.

Consumption

Consumers are billed for power and admission charges according to demand in the peak-load period of the region. These periods may be hard to identify, at least for medium and small-sized consumers. Consequently, many consumers will be inelastic to changes in the access charges. For the majority of consumers, electricity expenditures represent a minor budget share and changes in access charges will have modest implications. For some specific industries, electricity is a major input and access charges may be of larger importance. In general, we presume consumers to be less elastic than generators and efficiency losses resulting from access charges for consumers to be small.

Changes in the cost recovery charges

As discussed above, the current access charges have modest implications for the market efficiency. The generation access charges may lead to future losses, while consumption access charges at least for large consumers may induce some losses even today. A system with access charges for existing generators and exemption for new generation investments and consumers prevent losses. If such a system is politically infeasible, one should consider a system with elasticity dependent access charges where elastic participants (generators and large consumers) pay low or no access charges and inelastic consumers pay higher charges. This methodology requires more information about the flexibility attributes of various consumer groups.

7. The Norwegian Power Market through 2010

We apply Statistics Norway's Nordic electricity market model, Normod-T, to simulate a development path for the power market to 2010. Normod-T is an equilibrium model for the electricity market and it is documented in Johnsen (1998). The model gives electricity generation, consumption, trade and prices for 3 seasons and 4 load segments during the year and specify 5 demand groups in each of the four countries; Norway, Sweden, Denmark and Finland. In addition to electricity trade among these four countries, the countries' electricity trade with Russia, Poland and Germany is modeled.

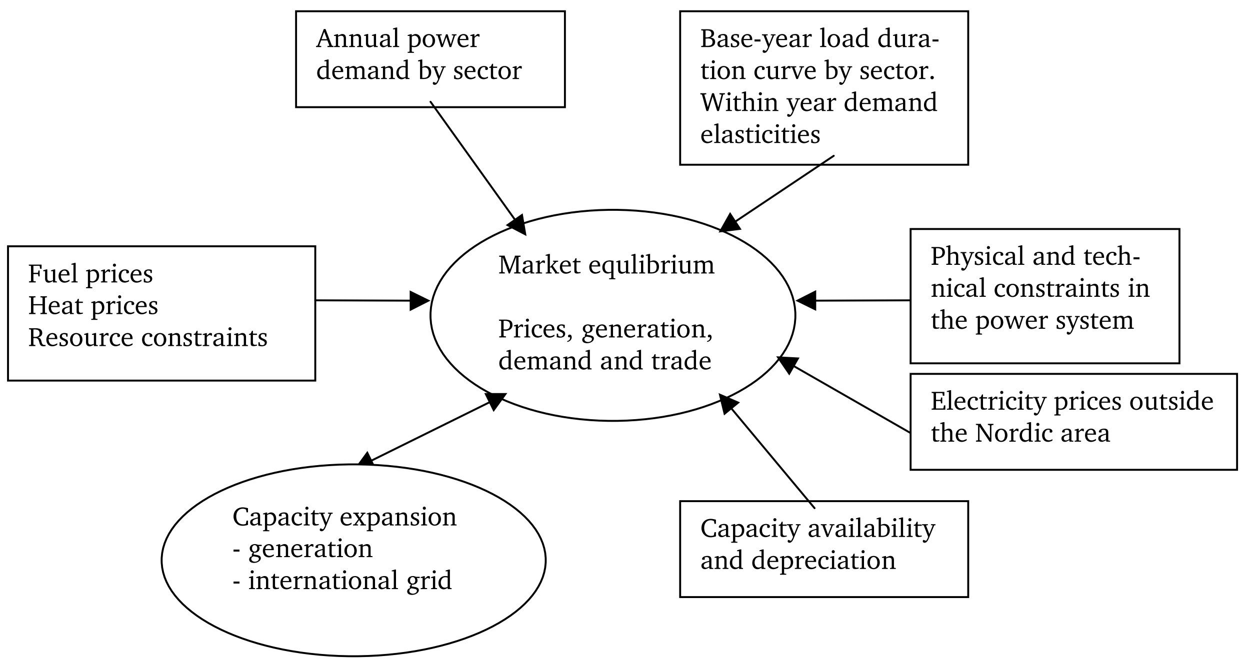
Figure 7.1 shows the main blocks of the model.

The main driving forces in the model are demand growth, depreciation of old generation facilities, fuel and heat prices and the development of international electricity prices. A large macroeconomic applied general equilibrium model for the Norwegian economy, MSG-6, is used to calculate annual electricity demand growth for Norway, while demand growth for Sweden, Denmark and Finland is based on national studies. For each demand group, the yearly electricity demand is distributed on seasons and load periods according to base year coefficients and the development of the periodic power prices. Each generation technology (k) in country l has an operating cost (OC) for season s, load mode h, given by

$$OC_{shkl} = \frac{q_{kl} - ph_{shl}(\bar{\mu}_{kl} - \mu_{kl})}{\mu_{kl}} + \alpha 1_k + \alpha 2_{hk},$$

where q is the fuel input price measured in NOK/kWh, ph is the price of heated water in NOK/kWh, while $\bar{\mu}$ is the total fuel conversion efficiency (electricity and

Figure 7.1 Model overview Normod-T



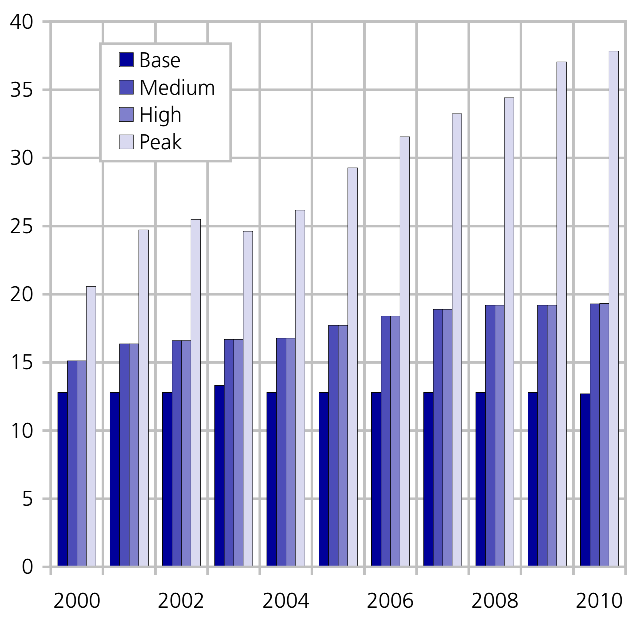
heat) and μ is the fuel conversion efficiency in electricity generation. For technologies producing only electricity, $\bar{\mu}$ is equal to μ. The two α's are variable costs other than fuel costs α_1 and a term indicating start-up costs α_2. This last term is mode specific and equals 0 if h = base-load, >0 if h = medium, high- or peak-load.[16] A technology not used in base-load generation has to be started daily and the estimated start-up cost is divided on the number of hours of operation in order to receive an estimate for α2. About 25 existing and new power-generating technologies are specified in the model. Capacity, costs, efficiency and fuel are specified for each technology.

Our Base case represents a business as usual scenario where the electricity sector proceeds from today's starting point without major changes in the energy policy. A gradual deregulation is undertaken in Germany, and two 600 MW cables between Norway and Germany operate from 2004. In the Climate scenario, a system with tradable CO_2 permits is gradually introduced from 2005. Given generation capacities determined in the base and climate scenarios, we simulate the influence of dry years.

7.1. Base Case

Fuel and other generation costs are fixed in real terms over the estimation period. Swedish nuclear power is reduced according to political decisions and annual capacity is 64 TWh from 2002. Old power generation equipment is gradually depreciated, and new investments are allowed from 2004. In Norway, we limit hydropower developments until 2010 to 8 TWh, while 5.6 TWh gas power may be produced using low price gas (Naturkraft). Additional gas power in Norway is assumed to pay the opportunity gas cost or the "world-market" gas price. Finnish power import from Russia is assumed to stay at today's level of about 6 TWh per year. For other Nordic countries we assume import and export prices to be constant until 2010. We expect the huge European surplus capacity to last for at least ten years. European prices are assumed to be 12 Nøre/kWh in base, 15.6 in medium-periods and 19.2 in high- and peak-periods. Based on information available in January/February 2000, Norwegian hydropower generation is assumed to be 116 TWh in 2000. However, when this is written it is clear that water inflow and snowfalls during winter 2000 has been much richer than initially assumed. The figures reported for 2000 should be viewed in this light.

Figure 7.2. Norwegian power prices in different load blocks during the winter season, Nøre/kWh (100 Nøre = 1 NOK)



Simulation of the model until 2010 result in power prices in Norway as shown in figure 7.2.

Baseload prices are stable until 2010. In baseload, Norway imports power from neighboring thermal power systems. As long as the export incomes cover the variable costs it is better for the thermal producers to export than to close down the power stations during the night. In fact, since start-up costs may be considerable, thermal producers may be willing to produce at a price lower than variable costs during the night in order to avoid stop-costs in the evening and start-up costs in the morning. Since variable costs (mainly fuel costs) are constant or decreasing during the simulation period (higher efficiency in new plants), it is not surprising that base prices are stable. Norwegian medium and high-prices reflect the shadow price of water. High flexibility in the hydropower system allows Norwegian generators to level out price differences over a large fraction of the day. Lower prices in the night are due to water-flow constraints and/or limits on the daily variation in the hydropower generation. Peak-prices grow steadily over the simulation period. While the peak price in 2000 is 30 percent higher than the medium and high prices the variation is around 100 percent in 2010. This illustrates increased value of capacity and the high expansion cost for capacity. Annual averages of the power price are close to the medium and high prices and increases towards the long-term marginal expansion cost for new power capacity.

Figure 7.3 shows Norwegian electricity consumption and generation until 2010. Norwegian hydropower capacity is expanded from 114 TWh in 2002 to 118.8 TWh in 2010. Two combined cycle gas power stations with an aggregate capacity of 5.6 TWh are established in 2004/5.

[16] Peak-load is 150-200 hours in each season, while base-, medium- and high-load is one-third each of the rest of the time within the season.

Figure 7.3. Norwegian power demand and supply, TWh

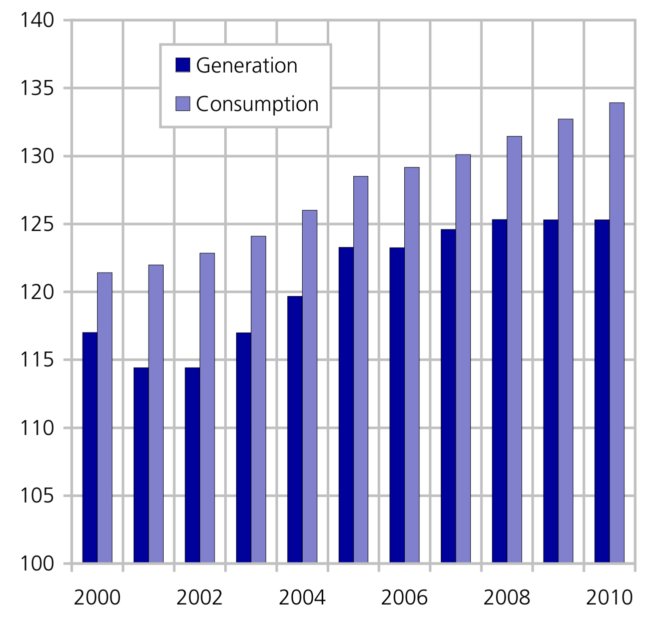
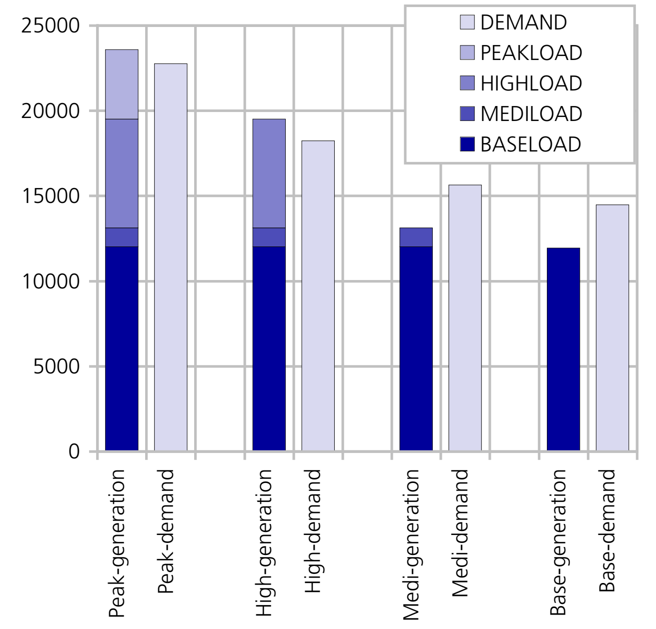


Figure 7.4 . Power generation and demand in various load segments during the winter season, 2010. MW



Norway is net importer of electric power during the whole simulation period. Net import is about 10 TWh per year in 2010.

The Norwegian trade pattern is as expected and observed the last years with export during high- and peak-load and import during medium and base-load.

Peak generation reach 23600 MW in 2010, while demand is 22800 MW. Thus, 800 MW is exported out of Norway during peak periods. Some generation capacity expansion and rapid price growth of peak power and thereby reduced demand makes this export possible. Nordic power trade matrixes for 2000 and 2010 are shown in table 7.1.

In 2000, Norway exports 4.9 TWh, mainly to Sweden and imports 9.3 TWh from Sweden and Denmark. Finland imports 6.1 TWh from Russia, while other Nordic countries export 11.8 TWh to other European countries and import 2.9 from the same. The trade patterns change towards 2010. In aggregate, Nordic countries' import 36.6 TWh from other European countries and export only 1.1 out of the Nordic area. Norway is net exporter to Sweden (2.8 TWh) and net importer from Denmark (3 TWh).

7.2. Climate Scenario

Tradable CO_2-permits are introduced from 2005. We assume the equilibrium price to be 20 NOK/ton CO_2 in 2005 and thereafter to increase with 20 NOK/ton per year until it reaches its final level of 100 NOK/ton CO_2 in 2009. We assume a European quota market from 2005 and this will affect power prices in countries outside the Nordic area and thereby the export and import prices of electricity. Power prices outside the Nordic area are increased with about 1.5 Nøre/kWh for

Table 7.1. Nordic power trade in 2000 and 2010, TWh

2000						
From:\To:	NOR	SWE	DEN	FIN	EURO	Sum
NOR	0	4.87	0.03	0.04	0	4.94
SWE	3.59	0	0	5.38	2.45	11.41
DEN	5.49	5.43	0	0	9.33	20.25
FIN	0	0.11	0	0	0	0.11
EURO	0.26	1.5	1.1	6.13	0	8.99
Sum	9.34	11.9	1.13	11.56	11.77	
2010						
From:\To:	NOR	SWE	DEN	FIN	EURO	Sum
NOR	0	4.73	0.56	0.01	1.12	6.42
SWE	1.87	0	0	3.83	0	5.7
DEN	3.53	2.47	0	0	0	6
FIN	0	0	0	0	0	0
EURO	9.66	9.2	11.63	6.13	0	36.61
Sum	15.06	16.4	12.18	9.97	1.12	

each 20 NOK the CO_2-quota price increases. This is based on coal condensing power with a fuel conversion efficiency of 0.40 as the marginal technology in Germany/Poland.

Increased price of CO_2-quotas makes fossil fuel based thermal power more expensive and Nordic electricity prices increase. Figure 7.5 illustrates the price movements in Norway.

Baseload prices increase more than medium and high-load prices since baseload power according to the model has the highest CO_2-intensity and since the fuel cost totally dominates baseload prices. Since Norway imports power in baseload periods, international baseload prices determine Norwegian prices in these periods. Norwegian medium and high-load prices equal the marginal value of water and represent an average of all periodic and seasonal prices. In addition,

Figure 7.5. Difference in prices from base to climate scenario, Nøre/kWh

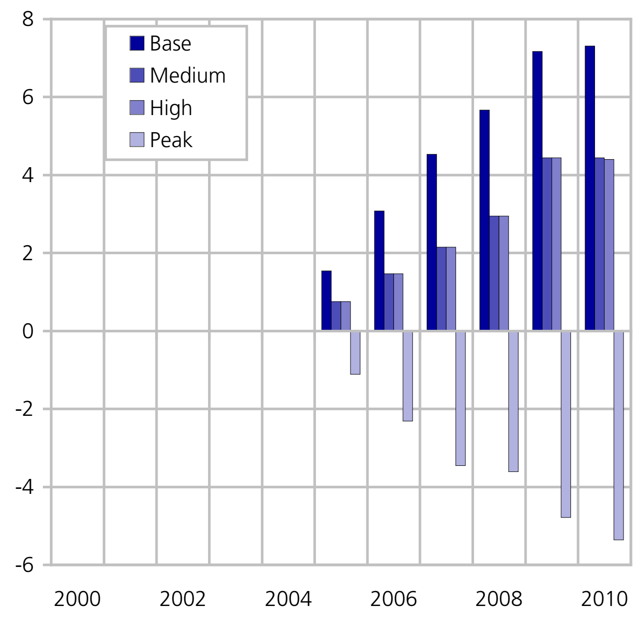


Figure 7.7. Demand and generation by load period in the climate scenario, 2010. MW

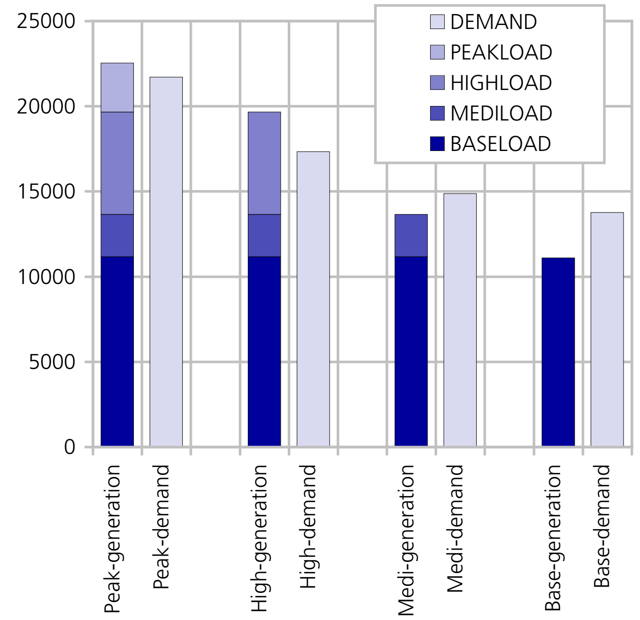


Figure 7.6. Difference in generation and consumption from base to climate scenario, TWh

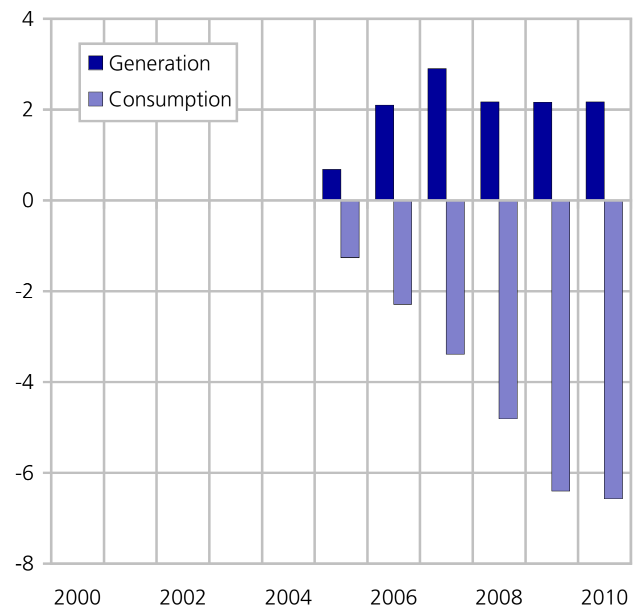


Table 7.2. Annual power trade in the climate scenario, 2010. TWh

Fra:\Til:	NOR	SWE	DEN	FIN	EURO	Sum
NOR	0	4	2.92	0.01	3.45	10.37
SWE	3.31	0	2.42	0.95	3.73	10.42
DEN	0	0.83	0	0	8.51	9.34
FIN	0	1.93	0	0	0	1.93
EURO	6.96	4.1	1.83	6.13	0	19.03
Sum	10.27	10.86	7.17	7.1	15.69	

marginal generation technologies have a lower CO_2-intensity in these periods. Peak prices fall because aggregate demand is reduced. This aggregate (scale) effect is much larger than the positive response on peak demand from reduced peak prices. Here, it is important to remember that in the model the price elasticities for all periods and sectors are -0.01, while the annual price elasticity is of order -0.25. Since peak prices are high at the outset, the percentage change in peak prices is much lower than expressed by the absolute price changes reported in the figure.

Figure 7.6 shows changes in annual generation and consumption. New generation is hydropower, while additional gas power is unprofitable. New hydropower is limited to 8 TWh during the period, while the cost of climate emissions limits more gas power. However, the gas power included in the base case continues to be profitable since we assume 5.6 TWh gas power to be available at a very low gas price (43 Nøre/Sm3) compared to extended gas power generation that is assumed to pay a "world-market" gas price (65 Nøre/ Sm3).

Consumption falls compared to the base case because prices are higher.

Peak load demand is 21700 MW in 2010, while generation is about 22500 MW or an export of 800 MW. The trade pattern is unchanged with export during peak and high periods and import in medium and baseload.

The annual trade pattern is shown in table 7.2.

In the climate scenario, Norway's power trade is balanced in 2010, while in the base case Norway was net importer of 9 TWh in 2010. Norway exports 3-4

TWh each to Sweden, Denmark and Germany and imports 3 and 7 TWh from Sweden and Germany.

7.3. Dry years

Norway and partly Sweden experienced a dry year in 1996, when snowfalls during the first part of 1996 were much lower than normal. This resulted in lower than normal inflow during the summer of 1996 and prices grew rapidly in the first part of the autumn. The last part of the autumn gave more rain than normal and the situation normalized during winter and spring 1997. On average, the day-ahead price reached 25 Nøre/kWh in 1996. This led to high power import and domestic demand reduction, see figure 2.3 in section 2.2 above.

In order to investigate impacts from one or two subsequent dry years in the period 2001-2010, we have taken power generation capacities as determined in the base and climate scenarios and simulated the effects of a 25 percent reduction in the annual inflow in Norway and Sweden. Since there are no multiyear water reservoirs in the model these simulations can be seen as simulation of the second out of two subsequent dry years in which only the yearly inflow is available for power generation. We have simulated all years during the period 2001 to 2010 as a dry year, since the effects depend on generation and transmission capacities actually available.

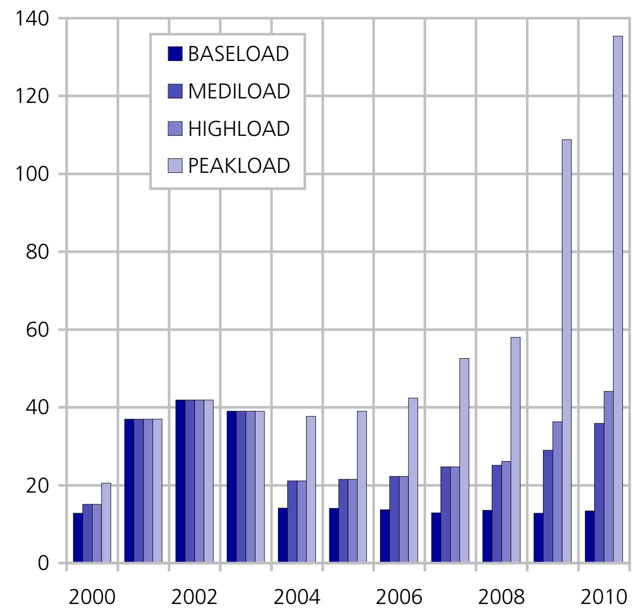
As can be seen from figure 7.8, the impacts from a dry year are very different before and after 2003/2004. Until 2004, we are to a large extent stuck with the capacities available today. From 2004, two gas power stations and two new transmission lines to Germany/ The Netherlands are operating.

The dry years in Norway and Sweden are not assumed to have any impacts on gas prices or German/Polish electricity prices. If such impacts occur, prices would have been somewhat higher. Both the price variation and level change from 2003 to 2004. Increased generation and transmission capacity from 2004 increase domestic non-hydro generation and power import. Thus, the average price falls. In order to understand the change in price variation, it is necessary to understand why prices vary in normal years. At least, there are two potential reasons for this variation. First, there is a limit on minimum hydropower generation of 8000 MW. This constraint may be motivated from minimum water flow regulations and some run of river production. Low demand and cheap import possibilities may make this constraint binding. If that is the case, the price in the base period will fall below the water-value and the shadow price of this constraint will equal the price difference between the base and medium period. This constraint is often active during summer when night demand is low. Second, there is in the model a limit on the difference between base and peak period hydropower generation. In our calculations, we limit peak period hydropower generation to be less than 90 percent greater than the base generation. This constraint may be motivated from regulations on water flow variation over the course of a day. Load variations are larger and peak prices higher in the winter, than during summer. Consequently, it is often beneficial to increase base-load generation a little in order to be able to generate more during high- and peak-load periods when prices are high. This constraint is often active during the winter seasons.

The latter constraint explains the price variation graphed in figure 7.8 except for the years 2001-2003 when this constraint is not binding. Energy is so scarce that it is not beneficial to increase base generation in order to be able to produce more during high and peak periods, simply because prices are equal in all periods.

The impacts from a dry year in the climate scenario are close to the effects described above. Import possibilities and the domestic gas power generation capacity are fully utilized and differences in fossil fuel prices have very limited influence on domestic prices.

Figure 7.8. Norwegian power prices during the winter season, dry year - base case capacities. Nøre/kWh



8. Conclusions and policy implications

We have analyzed the Norwegian power market and its ability to handle short-term situations with very tight balance between generation capacity and load. We study this issue from a theoretical, empirical and numerical viewpoint and find it probable that the market is able to handle such incidents. In addition, we have carried out numerical simulations of the impacts from a severe dry year, which reduces annual Norwegian and Swedish hydropower generation with 25 percent. A dry year will cause high prices, but we find it reasonable to say that the market is able to handle such a very dry year.

Through this project we have detected a number of design flaws that may prevent efficient solutions with regard to the issues we discuss in this report. We summarize these findings below. In addition, we point to the most important factors related to efficient supply, demand and trade decisions and incentives during periods with a tight power balance.

8.1. Design and rules

The regulator, NVE, is responsible for the design of the Norwegian power market. NVE should consider some design changes that would improve the power system's ability to handle situations with tight power balance in an efficient way.

8.1.1. Network regulation

NVE regulate regional grid companies' incomes and tariff structure. One main component is equal transmission price to comparable customers within the same network area. This rule prevents the grid companies to apply bottleneck charges that vary within their area. Thus, efficient pricing is not possible.

In addition, the connection between investment incentives and income regulation should be analyzed further. In section 4.2, we discuss a case where efficient investments in neighboring grids seem to be hard to realize despite socially beneficial.

8.1.2. Nodal price signals

NVE has advised Statnett to determine a maximum of 5 different price zones for the day-ahead market. These zones should have a constant geographical configuration. Statnett is advised to relieve intra-zonal congestion by sales and purchases in the regulation market. If there is intra-zonal congestion, zonal prices give inefficient price signals. Market prices are not equal to the true marginal value and cost of electric power. Thus, consumption and generation decisions will be taken on wrong premises and inefficiencies occur. Regional shortages may not be reflected in prices and efficient demand reductions become unprofitable.

One obvious example is the "Hasle-stair" administered by Statnett as system operator. High load in the Oslo area is met by reduced transmission capacity to Sweden due to bottlenecks in the grid from West into the Oslo area. Consumers in the Oslo area do not see the true cost of their own power use and there may be a large income transfer from generators to consumers in the Oslo area. At the same time Swedish import is reduced, which may cause higher than necessary prices in Sweden.

The obvious solution to this problem is to create a price area for the Oslo area when there are bottlenecks into Oslo. If Sweden apply a comparable strategy for determination of the export capacity to Norway it will reduce Norwegian import during peak periods and thereby reduce the markets ability to handle shortage situations.

8.1.3. Fixed charges in the grid

Residual incomes to grid owners are collected from fixed charges that depend on installed generator capacity (MW). These charges increase the cost of generation capacity investments and lead to lower than optimal capacities. Our numerical examples do not imply that this is a problem today, capacity investments are not profitable, even without these fixed charges. However, this may become a problem in the future and alternative ways of financing the grid should be analyzed.

8.2. Supply

In section 2.2, we investigate some high-price periods during 1999-2000. It seems to us that market power and withheld capacity may be a problem when demand reach a certain level. Bid curves for the regulation and day-ahead markets seem to be heavily influenced by incidents in the market. If the system operator reserves capacity for the regulation market, it seems to affect bids considerably. Market power problems at high load levels is well known from international literature and further analysis is necessary in order to find mitigation strategies.

The present situation in Norway with a number of proposed mergers between large regional generators is worrying. We expect transmission constraints to become more and more frequent as demand, generation and electricity trading increase. Therefore, we will experience increased existence of smaller, local import or export constrained areas. Mergers lead to increased local concentration and regional market power may become an increasingly important issue. Statnett, NVE and the Competitition council should be very aware of this future problem. If already merged it will presumably be a hard task to split or divest local companies.

8.3. Demand

Increased demand flexibility seems to be relatively inexpensive compared to generation capacity investments and therefore an efficient track to follow. Using market data for 1999-2000, we find some flexibility. However, there may be a potential for increased flexibility and we strongly recommend further studies of the current flexibility and the potential and cost of increased flexibility.

8.4. International trade

In our simulations, we assume efficient power trade with Germany and the Netherlands. During January 24th Sweden, Denmark, Finland and the northern part of Norway experienced very high day-ahead prices. Despite the very high prices, the power flow between Denmark and Germany was from Denmark to Germany or from a high price area to an area with lower prices. Obviously, there is still a potential for increased efficiency in the international power trade. Efficient trade may increase import in periods with very high prices and contribute to lower prices. Competitive power markets are still new and in their infancy in many European countries. Successful deregulation of national markets is a key factor for more efficient power trade between countries.

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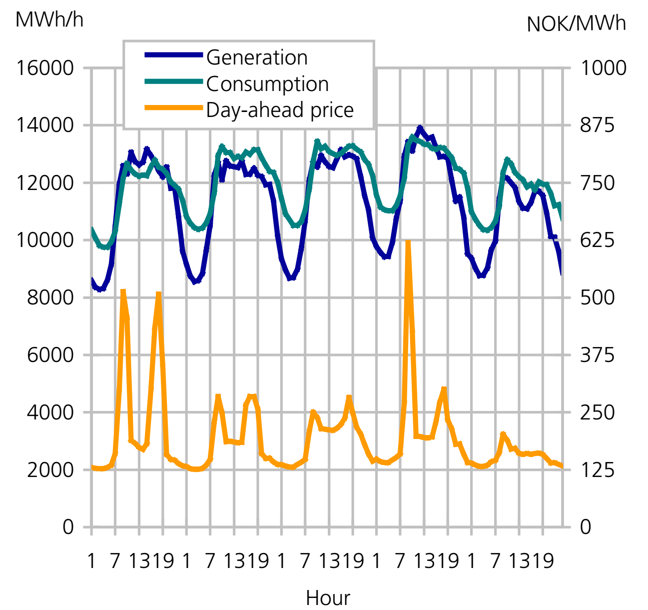
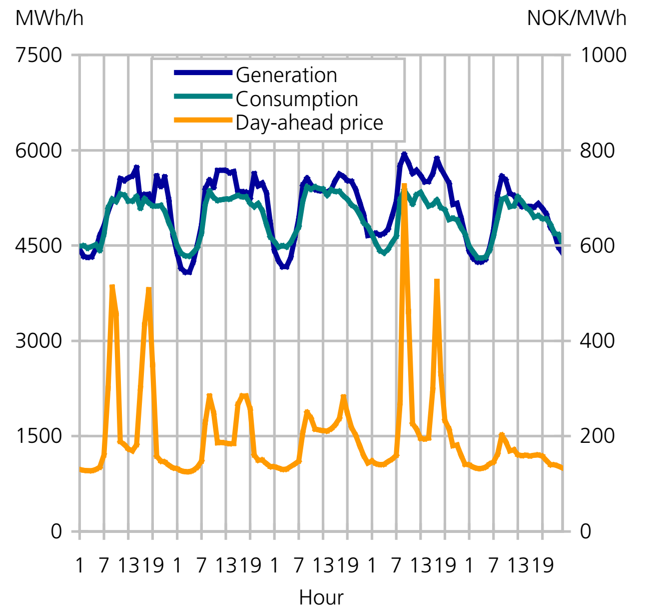
Appendix A

Figure A1. December 1999, Monday 13. until Friday 17. NO1



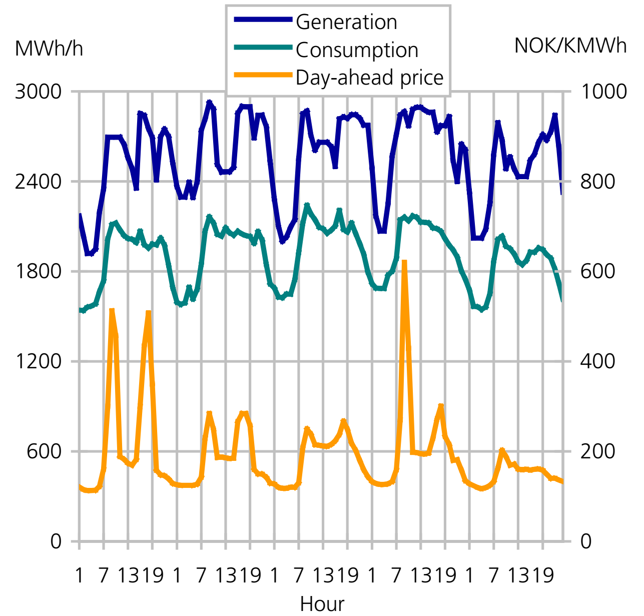
Source: Nord Pool

Figure A2. December 1999, Monday 13. until Friday 17. NO2



Source: Nord Pool

Figure A3. December 1999, Monday 13. until Friday 17. NO3



Source: Nord Pool

Appendix B

Incentives to actively adapt to price changes in Elspot

Assume:

1. The marginal cost of oil-fired heating is equivalent to a spotmarket price of k NOK/MWh
2. The end-user has a fixed power need of 100 kW
3. Gathering information and adjusting heating source to this has a cost in time beyond that of alternative c as follows
   Alt d: 2 min. pr. day
   Alt e: 4 min. pr. day
   Alt f: 6 min. pr. day
4. The end-user considers the following alternatives

a) Use electricity the entire period
b) Use oil the entire period
c) If the expected spotprice for the entire week, expectation as of Friday the week before, is lower than the marginal cost of oil-fired heating use electricity the entire week, if not use oil
d) If the expected price of electricity for the day, expectation as of Friday the week before, is lower than the marginal cost of oil-fired heating use electricity, if not use oil
e) If the average spotprice the next day is lower than the marginal cost of oil-fired heating use electricity, if not use oil
f) If the spot price of electricity for the hour is lower than the cost of oil-fired heating use electricity, if not use oil

	Number of days					
Period: week 48-99 until week 15-00	140					
Energy consumption 336 000 kWh		cost	cost reduction	rel. cost reduction	time used	gross cost reduction
	cost	reduction*	compared to alt. 3	compared to alt. 3	in minutes	per man-hour
k=200 NOK/MWh				**Oslo**		
a)	38,965.85	0.0 %				
b)	67,200.00	-72.5 %				
c)	38,965.85	0.0 %		0.0 %		
d)	38,965.85	0.0 %	-	0.0 %	280	-
e)	38,859.61	0.3 %	106.24	0.3 %	560	11.38
f)	38,319.08	1.7 %	646.77	1.7 %	840	46.20
k=150 NOK/MWh						
a)	38,965.85	0.0 %				
b)	50,400.00	-29.3 %				
c)	38,872.57	0.2 %		0.0 %		
d)	38,774.75	0.5 %	97.81	0.3 %	280	20.96
e)	38,246.19	1.8 %	626.37	1.6 %	560	67.11
f)	37,755.21	3.1 %	1,117.36	2.9 %	840	79.81
k=120 NOK/MWh						
a)	38,965.85	0.0 %				
b)	40,320.00	-3.5 %				
c)	37,063.03	4.9 %		0.0 %		
d)	36,979.86	5.1 %	83.17	0.2 %	280	17.82
e)	36,500.48	6.3 %	562.55	1.5 %	560	60.27
f)	36,120.81	7.3 %	942.22	2.5 %	840	67.30
k=100 NOK/MWh						
a)	38,965.85	-16.0 %				
b)	33,600.00	0.0 %				
c)	32,992.22	1.8 %		0.0 %		
d)	32,927.00	2.0 %	65.22	0.2 %	280	13.98
e)	32,691.59	2.7 %	300.63	0.9 %	560	32.21
f)	32,552.78	3.1 %	439.44	1.3 %	840	31.39

*) cost reduction compared to the cheapest alternative of alternative a and b

	Number of days					
Period: Week 50-99 and 14-00						
Energy consumption 33600 kWh	14					
		cost	cost reduction	rel. cost reduction	time used	gross cost reduction
	cost	reduction*	compared to alt. 3	compared to alt. 3	in minutes	per man-hour
k=200 NOK/MWh				**Oslo**		
a)	5,217.60	0.0 %				
b)	6,720.00	-28.8 %				
c)	5,217.60	0.0 %		0.0 %		
d)	5,217.60	0.0 %	-	0.0 %	28	-
e)	4,889.81	6.3 %	327.79	6.3 %	56	351.21
f)	4,818.13	7.7 %	399.48	7.7 %	84	285.34
k=150 NOK/MWh						
a)	5,217.60	-3.5 %				
b)	5,040.00	0.0 %				
c)	4,769.90	5.4 %		0.0 %		
d)	4,874.80	3.3 %	-104.90	-2.2 %	28	-224.79
e)	4,649.81	7.7 %	120.09	2.5 %	56	128.66
f)	4,367.99	13.3 %	401.91	8.4 %	84	287.08
k=120 NOK/MWh						
a)	5,217.60	-23.5 %				
b)	4,032.00	0.0 %				
c)	4,032.00	0.0 %		0.0 %		
d)	4,010.80	0.4 %	21.20	0.5 %	28	45.43
e)	3,998.01	0.7 %	33.99	0.8 %	56	36.42
f)	3,916.65	2.3 %	115.35	2.9 %	84	82.39
k=100 NOK/MWh						
a)	5,217.60	-36.9 %				
b)	3,360.00	0.0 %				
c)	3,360.00	0.0 %		0.0 %		
d)	3,434.80	-1.5 %	-74.80	-2.2 %	28	-160.28
e)	3,360.00	0.0 %	-	0.0 %	56	-
f)	3,355.25	0.1 %	4.76	0.1 %	84	3.40

*) cost reduction compared to the cheapest alternative of alternative a and b

Appendix C

Table C1. Detailed estimation results

Region 1 Explanatory variable:	Model 0	Model 1	Model 2	Model 3 (demand equation)
$\log(p_t)$	-0.06 (0.05)			-0.06 (0.01)
$D_t*\log(p_t)$	0.05 (0.05)			0.04 (0.02)
$\log(p_{t-24})$	0.03 (0.05)			0.03 (0.01)
$D_t*\log(p_{t-24})$	-0.02 (0.05)			-0.02 (0.02)
$\log(\overline{p}_t)$		-0.05 (0.04)		
$D_t * \log(\overline{p}_t)$		0		
$\log(\overline{p}_{t-24})$		0.04 (0.04)		
$D_t * \log(\overline{p}_{t-24})$		-0.01 (0.05)		
$\log(f_t)$			-0.06 (0.02)	
$D_t*\log(f_t)$			0.03 (0.02)	
R^2-adj	0.44	0.44	0.44	0.44

Region 2 Explanatory variable	Model 0	Model 1	Model 2	Model 3 (demand equation)
$\log(p_t)$	0.04 (0.02)			0.12 (0.002)
$D_t*\log(p_t)$	-0.04 (0.03)			0.11 (0.004)
$\log(p_{t-24})$	0.06 (0.02)			0.04 (0.002)
$D_t*\log(p_{t-24})$	0			-0.04 (0.01)
$\log(\overline{p}_t)$		0.01 (0.02)		
$D_t * \log(\overline{p}_t)$		-0.03 (0.03)		
$\log(\overline{p}_{t-24})$		0.07 (0.02)		
$D_t * \log(\overline{p}_{t-24})$		0.03 (0.03)		
$\log(f_t)$			0.06 (0.01)	
$D_t*\log(f_t)$			0.01 (0.01)	
R^2-adj	0.65	0.65	0.65	0.55

Region 3 Explanatory variable	Model 0	Model 1	Model 2	Model 3 (demand equation)
$\log(p_t)$	-0.04 (0.02)			-0.05 (0.002)
$D_t*\log(p_t)$	-0.01 (0.02)			-0.02 (0.01)
$\log(p_{t-24})$	-0.03 (0.02)			-0.03 (0.003)
$D_t*\log(p_{t-24})$	0.06 (0.02)			0.07 (0.01)
$\log(\overline{p}_t)$		-0.04 (0.02)		
$D_t * \log(\overline{p}_t)$		-0.09 (0.03)		
$\log(\overline{p}_{t-24})$		-0.01 (0.02)		
$D_t * \log(\overline{p}_{t-24})$		0.09 (0.03)		
$\log(f_t)$			-0.05 (0.01)	
$D_t*\log(f_t)$			-0.01 (0.01)	
R^2-adj	0.75	0.75	0.75	0.74

Region 4 Explanatory variable	Model 0	Model 1	Model 2	Model 3 (demand equation)
$\log(p_t)$	-0.05 (0.02)			0
$D_t*\log(p_t)$	0.07 (0.02)			0.16 (0.01)
$\log(p_{t-24})$	0.03 (0.02)			0.01 (0.004)
$D_t*\log(p_{t-24})$	-0.02 (0.02)			-0.05 (0.008)
$\log(\overline{p}_t)$		-0.04 (0.02)		
$D_t * \log(\overline{p}_t)$		0.05 (0.02)		
$\log(\overline{p}_{t-24})$		0.02 (0.02)		
$D_t * \log(\overline{p}_{t-24})$		-0.001 (0.02)		
$\log(f_t)$			-0.04 (0.006)	
$D_t*\log(f_t)$			0.04 (0.009)	
R^2-adj	0.66	0.66	0.66	0.60

Region 6 Explanatory variable	Model 0	Model 1	Model 2	Model 3 (demand equation)
$\log(p_t)$	0.16 (0.03)			0.22 (0.001)
$D_t*\log(p_t)$	-0.17 (0.03)			-0.04 (0.008)
$\log(p_{t-24})$	0.13 (0.03)			0.11 (0.001)
$D_t*\log(p_{t-24})$	-0.03 (0.03)			-0.06 (0.006)
$\log(\overline{p}_t)$		0.09 (0.02)		
$D_t * \log(\overline{p}_t)$		-0.15 (0.03)		
$\log(\overline{p}_{t-24})$		0.15 (0.02)		
$D_t * \log(\overline{p}_{t-24})$		0.01 (0.03)		
$\log(f_t)$			0.23 (0.01)	
$D_t*\log(f_t)$			-0.14 (0.01)	
R^2-adj	0.84	0.83	0.84	0.82

Region 7 Explanatory variable	Model 0	Model 1	Model 2	Model 3 (demand equation)
$\log(p_t)$	0			0
$D_t*\log(p_t)$	0.01 (0.02)			0.01 (0.01)
$\log(p_{t-24})$	0.05 (0.01)			0.05 (0.003)
$D_t*\log(p_{t-24})$	-0.3 (0.02)			-0.03 (0.005)
$\log(\overline{p}_t)$		0.01 (0.01)		
$D_t * \log(\overline{p}_t)$		-0.002 (0.01)		
$\log(\overline{p}_{t-24})$		0.03 (0.01)		
$D_t * \log(\overline{p}_{t-24})$		-0.01 (0.01)		
$\log(f_t)$			0.02 (0.01)	
$D_t*\log(f_t)$			0.01 (0.01)	
R^2-adj	0.74	0.74	0.74	0.74

Region 8 Explanatory variable	Model 0	Model 1	Model 2	Model 3 (demand equation)
$\log(p_t)$	0.04 (0.02)			0.07 (0.002)
D_t*$\log(p_t)$	-0.02 (0.03)			0.02 (0.005)
$\log(p_{t-24})$	-0.04 (0.02)			-0.05 (0.002)
D_t*$\log(p_{t-24})$	0.05 (0.02)			0.04 (0.004)
$\log(\overline{p}_t)$		0.02 (0.01)		
$D_t * \log(\overline{p}_t)$		-0.01 (0.01)		
$\log(\overline{p}_{t-24})$		-0.01 (0.01)		
$D_t * \log(\overline{p}_{t-24})$		0.01 (0.01)		
$\log(f_t)$			-0.04 (0.01)	
$\log(f_t)$			-0.03 (0.01)	
R^2-adj	0.67	0.67	0.68	0.66

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