Discussion Papers No. 472, September 2006
Statistics Norway, Research Department

Torstein Bye, Annegrete Bruvoll and Finn Roar Aune

The importance of volatility in inflow in a deregulated hydro-dominated power market

Abstract:
In 2002/2003, the Nordic hydro-dominated power market faced a short-term supply shock. In autumn, precipitation and inflow were unusually low. As a result, there were record high prices in the following winter. Questions were raised whether the deregulated market creates sufficient incentives to invest in new production and transmission capacity to secure supply when overall inflow fails. One fear is that the market could break down when precipitation and inflow fails during the whole year, which is more probable than a short-term extreme inflow failure. We apply a market model to simulate the market effects with two events: i) an overall inflow shortage 25 per cent lower than normal, and ii) a seasonally biased inflow shortage, as happened in 2002/03. The 25 per cent low inflow scenario shows that significantly higher price effects are likely to occur in the Nordic power market in the future than in the past. However, the price effects are less than one would expect when compared to 2002/03, but prices remain higher for a longer period of time. The simulations do not indicate any problems in the functioning of the market within these scenarios.

Keywords: Volatile power markets, deregulated power markets, security of supply

JEL classification: C61, D41, Q41

Acknowledgement: We are grateful to Erling Holmøy for valuable comments on an earlier draft. The study is partly funded by the Norwegian Research Council.

Address: Torstein Bye, Statistics Norway, Research Department. E-mail: tab@ssb.no

Annegrete Bruvoll, Statistics Norway, Research Department. E-mail: agb@ssb.no

Finn Roar Aune, Statistics Norway, Research Department. E-mail: fau@ssb.no

Discussion Papers comprise research papers intended for international journals or books. A preprint of a Discussion Paper may be longer and more elaborate than a standard journal article, as it may include intermediate calculations and background material etc.

Abstracts with downloadable Discussion Papers
in PDF are available on the Internet:
http://www.ssb.no
http://ideas.repec.org/s/ssb/dispap.html

For printed Discussion Papers contact:

Statistics Norway
Sales- and subscription service
NO-2225 Kongsvinger

Telephone: +47 62 88 55 00
Telefax: +47 62 88 55 95
E-mail: Salg-abonnement@ssb.no

1. Introduction

Hydropower constitutes an important share of electricity supply in many countries in Europe, South America, Canada and New Zealand, along with several US states. After disregarding transport energy, hydropower supplies more than 50 per cent of total energy use in several of these countries (BP, 2006).[1] One important aspect of hydropower-dominated markets is volatility in inflow and total supply, thereby stressing both the market and market functionality (see, for instance, Martinek et al., 2002; Bye, 2004). The impact of this volatility ultimately depends heavily on hydropower's share of the market and the balance between capacity and demand under normal inflow situations.

Before 1990, power markets around the world were vertically integrated, heavily regulated and, in most countries, a major portion of production capacity was publicly owned (Newbery, 2005). Country-specific strategies often comprised local self-sufficiency and limited inter-country transmission capacities. Market regulation and public ownership typically implied excess capacity investments, i.e., prices were lower than the total unit cost in new power plants. In the Nordic power market, this implied direct investment subsidies or a low rate of return on publicly owned power-producing plants (see, for instance, Bye and Hope, 2005, 2006). With high inflow and low prices, large overflows were frequently found and excess capacity secured delivery when inflow was low.

Starting around 1990, many countries commenced the deregulation process based on fundamental economic principles (Joskow and Schmalense, 1983). For examples of such deregulation in different countries, see Bye and Hope, 2005; Newbery, 2005; and Borenstein et al., 1996. Generally, the posited efficiency gains appear to have prevailed (Dubash and Singh, 2005) in Europe (Newbery, 2005; Bye and Hope, 2005), Chile (Pollitt, 2004), and some developing countries (Jamasb et al., 2004). In a number of instances, discussion of the performance of a deregulated market has been high on the agenda (CBO, 2001; Joskow, 2001; Borenstein et al., 2002, and Bye et al., 2003).

Following deregulation, most markets have experienced diminishing investment in new production capacity, as prevailing market prices do not justify the marginal costs of expansion (Bye and Hope, 2005, 2006). The typical annual increase in demand following economic growth, increases prices, due

[1] Hydropower constituted more than 25 per cent of total energy consumption in 2005 in the following locations; in Europe: Norway, Iceland, Sweden, Austria and Switzerland; in South America: Argentina, Brazil, Colombia, Peru and Venezuela; in Oceania: New Zealand; and in Canada. In the US, the largest hydro generation capacity is found in Alabama, California, Florida, Illinois, Texas, Pennsylvania and Ohio.

to increasing marginal costs, also in the long run. In deregulated and relatively closed and hydro-dominated markets, volatile equilibrium electricity prices must mirror variation on the hydro supply side, although supplementary technologies, transmission facilities and trade smooth price variations. Since changes in production must fully absorb the inflow fluctuations, prices become more volatile.

So far, historic experience in a deregulated market offers limited insights on the reaction to such stresses. The Nordic regulated market with surplus capacities has experienced low inflow several times before, but as yet not under the deregulated regime where capacities are more in line with demand. Hence, a study of the possible outcomes of inflow failures in deregulated energy markets is important in order to prepare to meet possible inflow shortages in the future.

The low inflow to the Californian hydro reservoirs in 2000/01 illustrated how important it is to consider interacting factors. This shortage led to an unexpected meltdown of the market, as several factors enhanced the effects. Planners failed to foresee the interplay with increasing natural gas and NO_x permit prices, sharply increasing demand and possible market design failures (Joskow, 2001; Martinek et al., 2002; Wollack, 2003). The most recent low inflow situation in the Nordic market was during the winter of 2002/03 and in 2006. In 2002/03, the Nordic countries experienced an abrupt low inflow to the hydropower system in the autumn of 2002, and market prices escalated for a short period of time. Bye et al. (2003) evaluated this event and concluded that the market handled the shortage well. The 60 per cent drop in inflow into the Nordic system during the autumn rain period was characterized as a 0.5 probability event (ECON, 2003). In comparison, the annual drop in inflow in 2002 compared to normal inflow was only some 6 per cent. Inflow simulations for the existing hydropower system showed that it is 10 times more probable that the Nordic power market will be exposed to a drop in annual inflow of 25 per cent or more. Actually, the market experienced an annual inflow 20 per cent lower than normal as late as 1996, but the market at the time was not yet fully deregulated and adequate capacity to handle the event without extreme price effects still prevailed.

Concerns regarding the robustness of the Nordic deregulated power market relate to increasing energy costs for industries and households, and distributional effects among households. Questions arise as to the political acceptability of large price increases, and whether the mechanisms in the recently deregulated electricity marked can ensure sufficient future power supply. In this respect, it is an open question as to what is more severe: an abrupt shortage (as in 2002), or as is more likely, a lower inflow over several seasons. Storage capacities and the interrelationship between hydro and thermal markets and transmission capacities are key balancing factors to consider when investigating the outcome of severe inflow shortages.

In this article, we study how a deregulated market with no excess capacity handles an inflow 25 per cent lower than normal, evenly distributed across seasons. According to historic inflow data, this event is a relatively likely scenario. Within the framework of a Nordic electricity equilibrium market model, we compare this scenario to a simulation of the 2002/03 events and a normal inflow scenario. To show the model's relevance, the 2002/03 simulation is compared to the actual event. One may suspect that an overall inflow shortage involves a smoother adjustment than an extreme short time lack of precipitation. On the other hand, due to reservoir capacity and transmission constraints in the system, a larger overall inflow shortage might involve greater challenges over time. We also discuss these scenarios in light of the event in 1996/97, when the inflow shortage was 20 per cent, relatively evenly distributed over seasons. However, the production capacity under normal inflow conditions was high compared to normal demand. Our simulations indicate no problems in market clearance under these inflow shortage scenarios. However, producers appear to mark up prices when inflow fails.

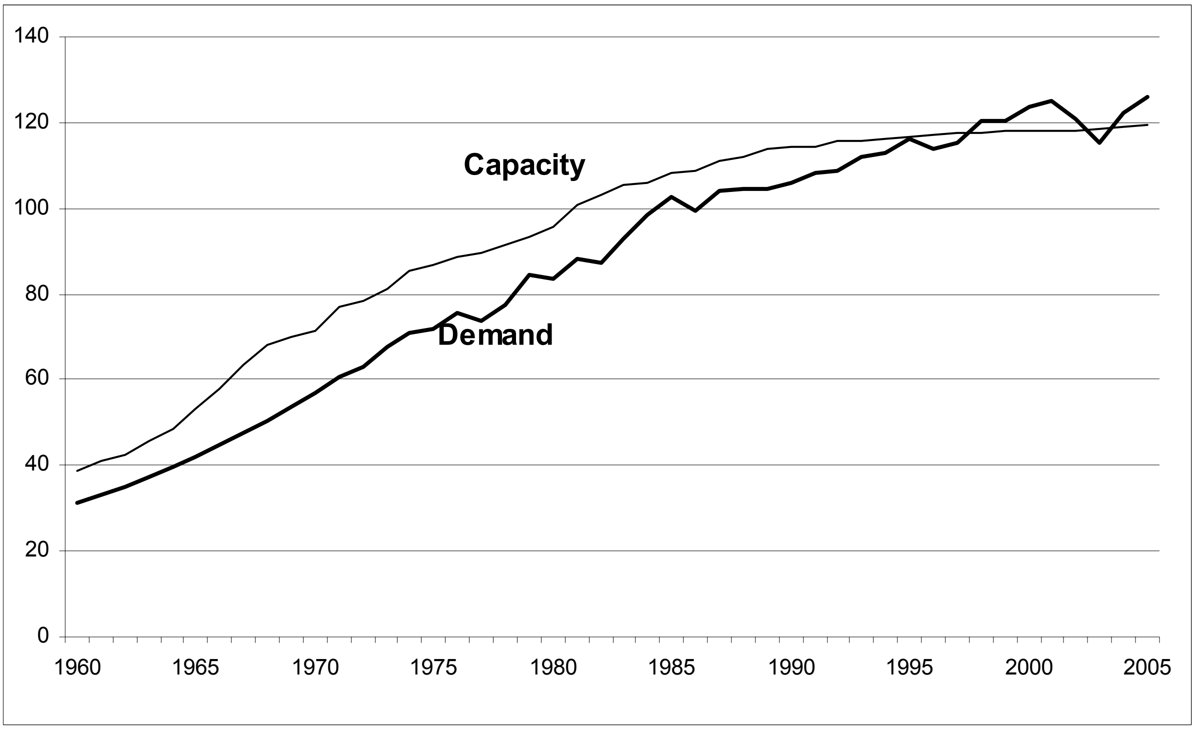
2. Background

During the period of regulation, Norway and most other European countries pursued a strategy of self-sufficiency with respect to power supply, often on a regional basis. This strategy implied investment in sufficient production and/or transmission capacities to cover both peak load demand and total demand, even with low inflow events, to hinder large increases in prices. Capacity[2] then overrode normal demand for long periods of time, as shown in Figure 1.

---

[2] We define capacity as the potential to produce electricity in a normal inflow year. The annual production may override this potential as the generation capacity is dimensioned to produce in peak periods. The load varies between 9000 and 23000 MW in the Norwegian system.

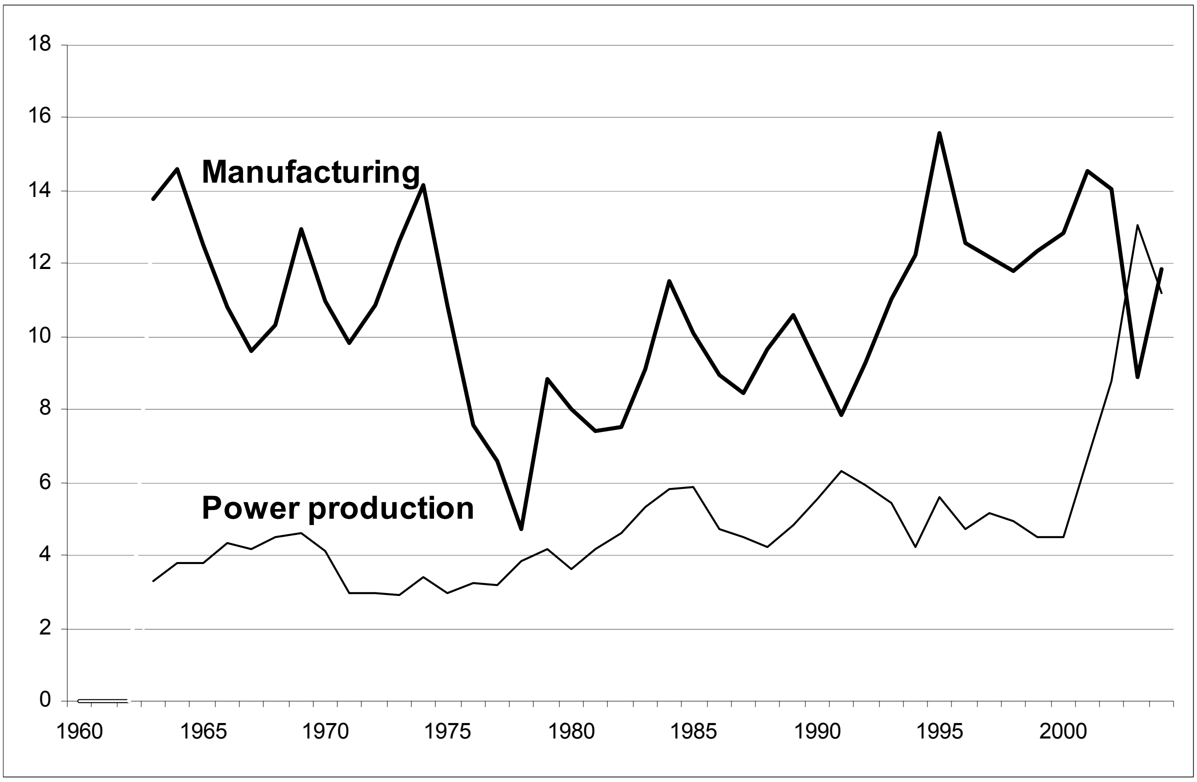
Figure 1. Production capacity and demand. TWh



Source: Bye and Hope (2006)

One consequence was low average prices. When inflow was high and demand low compared to production and transmission capacities, there was overflow and loss of water value. Prices were reasonably stable when inflow was low and sufficient transmission capacity existed. The rate of return on investment turned out to be low compared to the alternatives in potentially competing activities, as shown in Figure 2 (the narrow gap in the late 1970s and early 1980s is associated with manufacturing business cycles). The low rate of return compared to manufacturing is actually underevaluated by the figure as the hydro power system with increasing marginal cost normally would earn a groundrent additional to a normal rent.

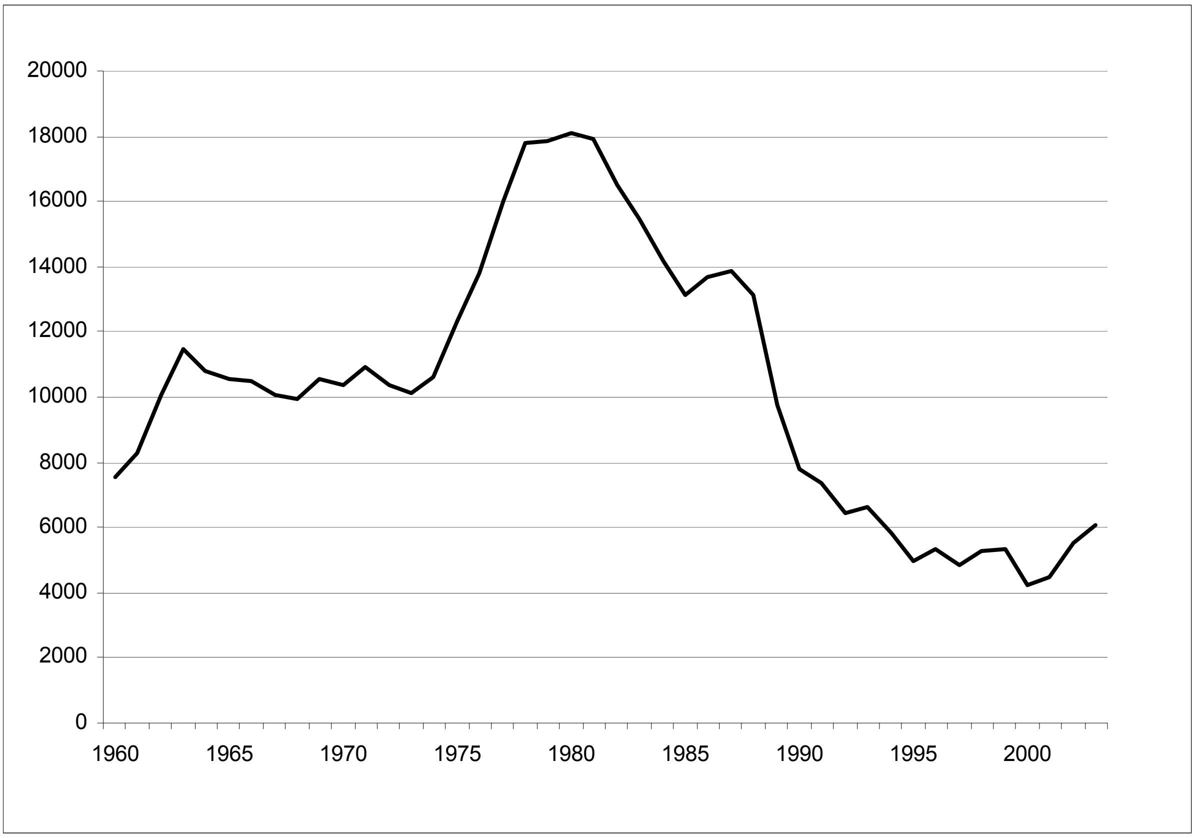
Figure 2. Rate of return in manufacturing and power production. Per cent



Source: Bye and Hope (2006)

As the total cost of this strategy (the low rate of return times volume) increased, and environmental concerns were more focused, investment in new capacity dropped after about 1980: see Figure 3 and Bye and Hope (2006) for a more detailed discussion. After the deregulation of the Nordic market from 1991, demand increased and is now above the normal Norwegian production capacity level (Figure 1). The overall price level and the rate of return have increased significantly after 2000. So far, these deregulation effects are in accordance with theory. When capacity is scarce compared to demand, the possible upside on prices is higher than when capacity is high compared to demand. The downside on prices is also higher, as all variation in inflow is market oriented and the spilling of water is not allowed due to market power concerns. What remains to be tested is the effect of significant reductions in supply, due to inflow failure, in a time of steadily increasing demand.

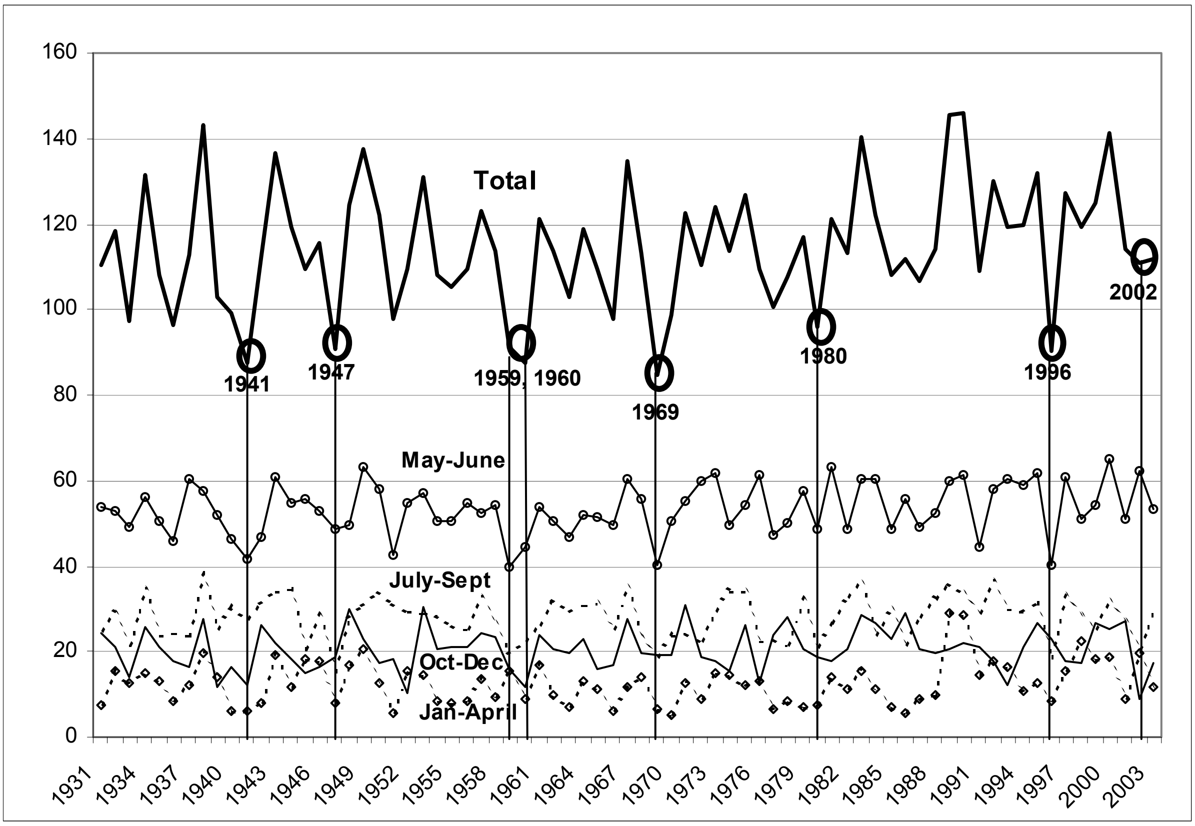
Figure 3. Investments in power supply. Mill NOK. 2005 prices



Source: Bye and Hope (2006)

Historical variations in inflow sheds light on the risk of facing electricity shortages in hydro-dominated power systems. Figure 4 presents the inflow into the Norwegian hydropower system since 1931, mirroring the extensive variation in precipitation over both seasons and years. The 90 per cent confidence interval for the yearly inflow to the reservoirs, is 90–150 TWh, i.e., $\pm$ 25 per cent variation around the expected value of 119 TWh. The market effects depend not only on the overall inflow variation, but also on the seasonal spread. Figure 5 illustrates the spread in seasonal variation in dry (less than average inflow) and wet (more than average inflow) periods in the latest 74 years.

Figure 4. Simulated[3] seasonal inflow to the reservoirs, at given 2003 capacity, TWh



Source: NVE

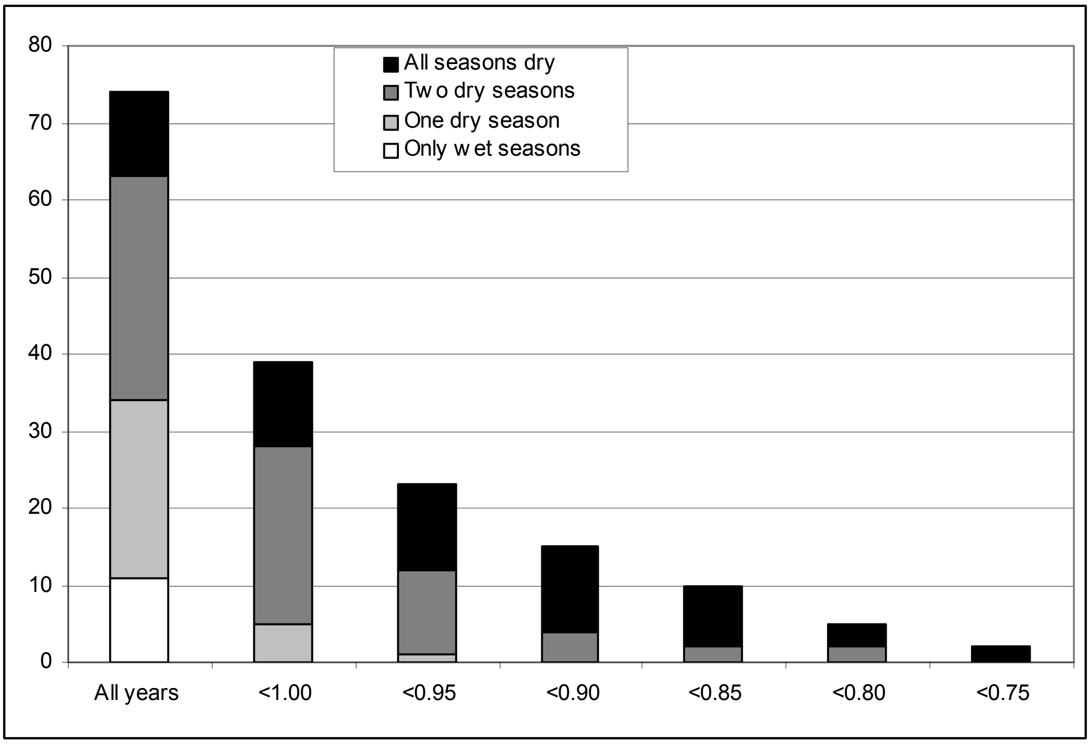
As seen from the first bar in Figure 5, only 11 years consist of three wet seasons[4]. Sixty-three years have at least one dry season, of which 11 years are dry in all three seasons, 29 are dry in two seasons and 23 years have only one dry season, as in 2002.[5] The bars to the right show the seasonal distribution when inflow is lower than a certain level compared to normal. For 39 years, the inflow was lower than normal (<1). The less the inflow, the more frequent are the observations of at least two or more dry seasons, e.g., 15 years (20 per cent) had an inflow lower than 90 per cent of normal, in which 11 were with all dry seasons. For two years, the inflow was less than 75 per cent of normal, and all seasons were dry. Hence, when studying the effect of severe inflow shortages, evenly distributed drought over all seasons is the most plausible assumption.

[3] The series are simulated inflows to the existing reservoir system for the years shown. Source: NVE

[4] We define three seasons, a snow accumulation season from January to May, a melting period from May to September, and a rainy period from September to December.

[5] Observations with less than 80 per cent inflow compared to normal are 5 from 74 years (1941, 1959, 1960, 1969, 1996), i.e., 8 per cent of all years. Fifteen years had less than 90 per cent of normal inflow (1933, 1936, 1940,1941,1947, 1951, 1959, 1960, 1963,1966,1969, 1970, 1977, 1980, 1996), i.e., 20 per cent of all years are drier than 2002.

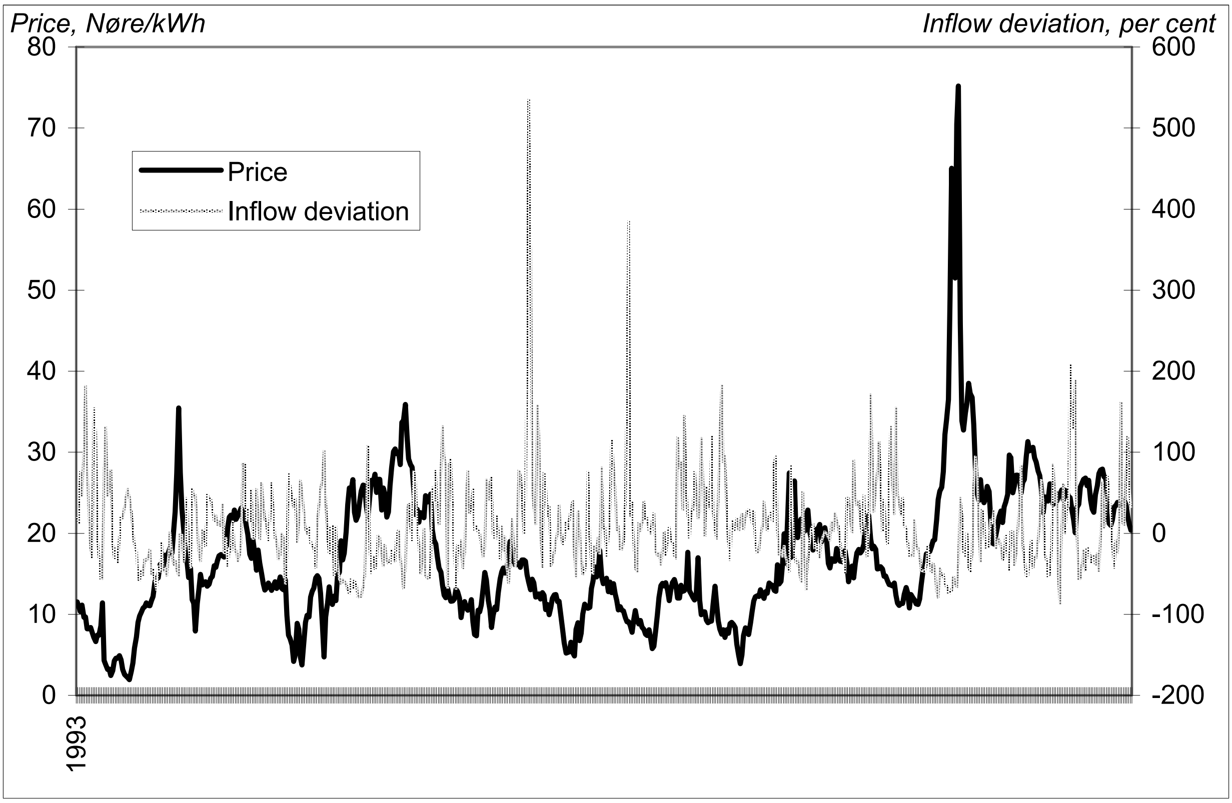
Figure 5. Summary statistics for the number of dry years and seasons in intervals for the percentage shortage compared to normal annual inflow, 1931–2004, number of years



Source: SSB/NVE

Inflow variation may severely impact power prices, since hydro capacity constitutes some 60 per cent of the total supply side in the Nordic market. The market is fully integrated, and the NordPool exchange handles day-by-day trade, equalizing prices between regions when transmission capacities are sufficient. When bottlenecks occur, area prices (Norway) or repurchases (Sweden) clear regionalized markets. Due to differences in regional shortages, transmission capacities may be more constrained. Figure 6 shows a high correlation between the deviation in inflow (compared to the average over the last 70 years) and the NordPool system prices from 1996 to 2005. In addition, other variables may help to explain some of the price variation, for instance transmission constraints, fuel prices and demand variation due to business cycles and outdoor temperature.

Figure 6. Difference in reservoir level in per cent and electricity prices in Nøre /KWh, 1993–2004



Source: Statistics Norway

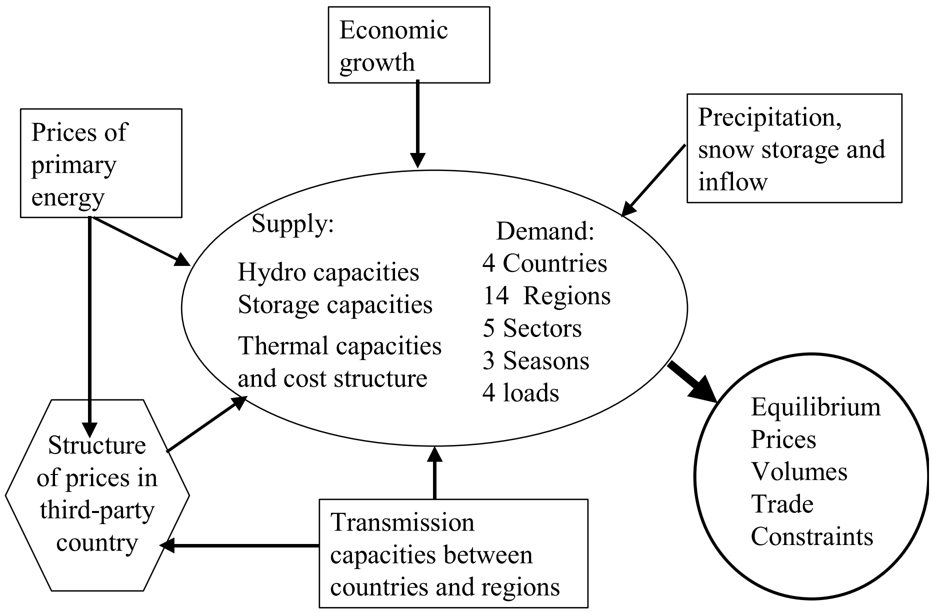
As shown in Figure 6, prices are low when inflow is higher than normal, and when inflow is lower than normal, prices are high. In 1996, inflow was about 20 per cent lower than normal, with a higher than average loss in the snow-melting period. Still, the variation in relative low inflow over seasons was not large, and the adjustments to production and prices were soft and even. Average prices in 1996 were about twice those of the other years from 1993 to 1999 (except 1994). Capacity was about 3 per cent above demand (Figure 1). In 2002, inflow was approximately 6 per cent lower than normal while the early winter inflow and the snow-melting period were above normal. What characterized the 2002 event was the total loss of autumn rain, which was a sudden event that escalated prices. The average price in 2003 was about twice the price level in 2000, and the peak price in January 2003 was more than 80 per cent higher than the last record from 1996. Despite average prices increasing after 2003, they still appear to be below the cost of expanding capacity as the cost of gas power plants is about 25 per cent higher than the future price on NordPool.

This illustrates that a deregulated market faces both higher prices before capacity expands and a higher risk for running low on supply when precipitation fails. The actual responses to inflow shortages depend on the responsiveness of the demand side. In a simultaneous demand and supply model with hourly equilibrium prices and volumes, Bye and Hansen (2006) estimated the NordPool market elasticities of demand. They found that demand is inflexible in the short run[6]. Hence, a severe inflow shortage may potentially escalate prices.

3. The model

As the basis for the analysis, we apply a detailed model for the Nordic power market, Normod-T (Aune et al., 2000a; Aune et al, 2000b; Aune, 2003). The model specifies all existing power-generating capacities in the Nordic countries (Norway, Sweden, Finland and Denmark) by capacity and cost, all transmission line capacities, and electricity demand in five sectors by country. Figure 7 gives a basic overview of the model structure. Based on estimations by Bye and Hansen (2006), producers mark up cost when hydro inflow is lower than normal. This mark-up may reflect both capacity constraints and the abuse of market power. The four countries are divided into a total of eight regions with both intra- and inter-country trade capacities.

Figure 7. The power market model structure



[6] The short-term demand elasticity for the Norwegian market was estimated to be close to 0.05 on average while the short-term Swedish demand elasticity was 0.02 on average. Conf. that the estimated elasticities are on wholesale prices. Since transmission and distribution costs and taxes constitute almost two-thirds of purchaser prices, the elasticity of the purchaser price is three times higher, though still relatively low, especially in the Swedish market. The Swedish market constitutes approximately 50 per cent of the Nordic electricity market. The Norwegian and Swedish markets together constitute some 75 per cent of the Nordic market.

In addition to power transmission among the regions within the Nordic countries, the model includes transmission capacities to countries outside the Nordic region (Russia, Poland, Germany and The Netherlands). These markets are mainly thermal-based. Due to restricted transmission capacities in both the short and long run, increased imports from these countries can only partly meet variation in inflow in the Nordic countries.

3.1. Power supply

We specify 25 power-generating technologies by capacity, variable and fixed costs (inclusive of fuel type and price) and fuel conversion efficiency. Moreover, each generation technology is represented by a number of physical and technical constraints, which restrict the system operation possibilities in each period. Binding constraints trigger positive capacity prices. The model is divided into 12 different segments during the year (*s* times *l*): two winter periods and one summer period (seasons, *s*), each capturing peak, high, normal and low demands/supply (loads, *l*).

The electricity price P_{rsl} in each region *(r)*, season *(s)* and load *(l)* reflects marginal cost and a mark-up

(1) $$P_{rsl} = f\left(X_{rsl}, \overline{X*}_{rsl}, PF_{rsl}, D_{rsl}, R_s, \overline{CAPT}_{rsl}\right)$$

which is a function of the vectors of production by technology X_{rsl}, production capacities by technology, $\overline{X*}_{rsl}$, primary energy fuel prices, PF_{rsl}, other operating cost, D_{rsl}, and transmission capacities, $\overline{CAPT}_{rsl}$, all per region, season and load, and the water level in the reservoirs, R_s, per season. The reservoir element, R_s, in the marginal cost follows Bye and Hansen (2006), and works as a mark-up on the thermal prices when the reservoir level is low, i.e., when water inflow is scarce and thermal capacity in the Nordic market is concentrated, producers may exploit market power.

The production costs define the alternative value of water when capacities are sufficient. The capacity limits for both production and transmission define a shadow value for capacity in price formation. The value of water also depends on reservoir capacities, i.e., the possibility of storing water between periods, and the possibility for thermal producers to exploit market power (Førsund et al., 2003; Crampes and Moreau, 2002; Bushnell, 2003; Borenstein et al. 1999, 2000, 2002; Bye and Hansen, 2006).

The model specifies four load modes that capture utilization times and the variation in flexibility among technologies. Thermal power generators consider start-and-stop and cycling (lower than full capacity utilization in running plants) costs. Operating costs in hydropower plants are low, but a number of physical and institutional constraints given through the operating concession act to limit the operational flexibility of the hydropower generation equipment. Due to storage limitations and regulations governing the minimum flow of water, base load hydropower generation has to be equal to or greater than a lower limit each season. Although hydropower production can be regulated at low costs, there may be environmental or operational constraints that vary over the day, or between base and peak generation. We apply an upper limit to the increase in hydropower generation from the base to the peak load mode. Finally, there is an upper limit on reservoir capacity, or on the aggregate generation of energy from hydropower resources in the two winter periods. Generation and transmission capacities are assumed to be fixed in the short run.

3.2. Power demand

The demand side is divided into five consumers in each load and region, with differences in the composition of volume over loads and in elasticities. This implies different macro market elasticities over loads and seasons, which is an important feature of the model when analysing shortages in inflow.

Electricity demand from sector j in region r, season s, and load l, Z_{jrsl} depends on the relevant load purchaser price, PC_{jrsl}, and the relevant activity level, w_{jr}:

(2) $$Z_{jrsl} = \beta_{0jrsl} + \beta_{1jrsl} PC_{jrsl} + \beta_{2jr} w_{jr} \, .$$

The activity level impact is general for all loads and seasons, i.e., the β_{0jrsl} coefficient captures the base differences in demand by season and load. The purchaser price:

(3) $$PC_{jrsl} = \left\{P_{rsl} + m_{jrsl} + t_{jr}\right\}\left(1 + \omega_{jr}\right)$$

is the sum of a common load and a season-specific wholesale price (P_{rsl}) for all consumers, a transmission and distribution margin (m_{jrsl}) that varies among consumers and a consumer- and region-dependent electricity commodity tax (t_{jr}). The inflow impact on different end users then vary due to both differences in end user price changes and differences in elasticities among consumers. This further influences the regional market equilibrium, since the industry composition varies among regions (and countries). Most consumers are also charged a multiplicative value-added tax, $\omega_{jr.}$, which may vary by consumers[7] over regions.

When there is no regional constraint in the transmission network, the wholesale price is common among regions, $P_{rsl} = P_{sl}$. When there are no network constraints, no hydro storage capacity and generation capacity constraints, the market clears on one unit price across all regions, seasons and loads, such that $P_{rsl} = P$.

3.3. Solution of the model

Trade between countries and regions happens to be limited by transmission capacity. Within one load block, trade is restricted to only one direction. Transmission networks further link all the Nordic countries to non-Nordic 'third-party countries'. We assume that the load and season prices in the third-party country follow the observed distribution, while the price level follows the primary energy cost in thermal plants. The transmission capacity between the Nordic countries and the third-party countries is limited and often binding when inflow drops.

There is one unique equilibrium condition for each load block, where the power generation plus import must be greater or equal to the sum of domestic demand and export. Producers of hydropower maximize the value of water over periods, taking into account storage capacities, production capacities, regulation constraints and transmission constraints (Førsund, 2005). Producers of thermal plants aim to maximize marginal revenue net of taxes where the mark-up is endogenous, depending upon the difference between the normal and actual hydro reservoir level.

4. Scenarios

Inflow data shows that the 90 per cent confidence interval for inflow captures normal inflow ± 25 per cent (Figure 1). The very low inflow scenario is our focus. This *General inflow shortage scenario* has a 25 per cent inflow shortage compared to normal, evenly distributed over an inflow year. We compare this scenario to our *2002/03 scenario*, which is based on the actual inflow in 2002 and 2003, i.e., an inflow 48 per cent above normal during the spring of 2002, and 60 per cent less than normal in the autumn of 2002 and an inflow 7 per cent below normal during 2003. Our *Reference scenario* is the normal inflow scenario.

---

[7] In Norway, manufacturing industry is exempted.

We model three seasons, *Winter 1* (winter/spring), *Summer*, *Winter 2* (autumn/early winter). We simulate the model for the two years *Year 1* and *Year 2*. The inflow shortages occur in *Year 1*, while the intertemporal water disposal influences the market adjustments both years. Inflow in *Year 1* also depends upon precipitation in the year before, *Year 0*. The most important periods with respect to inflow are summer melting and rainfall during the autumn. Summer melting in *Year 1* depends upon snowfall in the two previous seasons, *Winter 2* in *Year 0*, and *Winter 1* in *Year 1*. Hence, in the *General inflow shortage scenario*, we assume that precipitation in all seasons in *Year 1*, and in *Winter 2, Year 0* is 25 per cent lower than normal. In the *2002/03 scenario*, precipitation is higher in *Winter 2*, *Year 0*, in line with observations. We assume normal precipitation in *Year 2* in both scenarios, but reservoir levels turn out to be significantly lower than in a normal year, due to catching up. This keeps market prices high, while producers build up the reservoirs. This *General inflow shortage scenario* is a 2 per cent probability scenario (Figure 5). A 20 per cent evenly distributed inflow shortage is close to a 3 per cent probability.

Hydropower producers maximize the value of water over all loads and seasons, based on predictions about future inflows. In all scenarios, we assume normal inflow predictions at any time, while historic inflow, accumulation of snow and reservoir capacity at present is well known. Hence, inflow shortage to the reservoirs affects the value of water, both presently and in the future.

Higher prices reduce demand and storage levels eventually return to normal. Based on the 2002/03 experience, we assume that approximately 40 per cent of the inflow loss is made up in the market during the following year. Catching up then implies a back to near-normal storage level in approximately three years. Accordingly, we assume a catching up of 80 per cent of the *excess* inflow in the two first seasons of the *2002/03 scenario*, which is a disproportionate share due to the risk of overflow.

Table 1 summarizes the inflow scenario assumptions in the inflow shortage year, *Year 1*. A 25 per cent continuous shortage and normal inflow expectations in *Winter 1* imply a 12.5 per cent expected average reduction over the season. The market takes into account that a lower than normal snowfall during *Winter 2* in *Year 0* and *Winter 1* in *Year 1* reduces future melting in the summer season. The average *expected annual* inflow reduction compared to a normal year is at this stage only 10 per cent. In *Summer*, the expected annual accumulated shortage has increased to 18 per cent, and to 23 per cent in the last season. Due to production adjustments, reservoir filling is lower than normal at the beginning of *Year 2*.

Table 1. Divergence compared to normal, per cent, Year 1

	Winter 1	***Summer***	***Winter 2***
The *General inflow shortage scenario*			
Inflow from last year's snow:		–25	
Actual divergence in precipitation this season	–25	–25	–25
Average anticipated divergence in inflow this season	–12.5	–21	–12.5
Expected inflow divergence over the entire year	–10	–18	–23
The *2002/03 scenario*			
Inflow from 2001 snow:		28	
Actual divergence in precipitation this season	48	–2	–59
Average anticipated divergence in inflow this season	24	13	–29
Expected inflow divergence over 2002	15	14	–1

In line with historical experience, precipitation in *Winter 1* is far higher than normal in the *2002/03 scenario*, at 48 per cent. Through the autumn, the precipitation shortage is significant. Then, the market adjusts slowly towards normal reservoir levels in the next year, *Year 2* (corresponding to 2003).

While stochastic inflow influences the supply side, stochastic temperature variation influences the demand side. We assume normal temperatures in all scenarios, however, we comment on the importance of the observed temperature variation in the 2002/03 scenario.

4.1. Results

The model simulations indicate that severe market shocks in terms of price increases and production and consumption adjustments are likely to occur in the future in a deregulated Nordic power market regime. In the *General inflow shortage scenario*, the simulated price increases are far above the *2002/03 scenario*, and the corresponding demand response significantly stronger. Imports from thermal plants in both common Nordic market and third-party countries helps by levelling off the effects.

Still, the price increase is by no means preposterous. On average, the annual price increase corresponds approximately to the experienced average production cost increase in gas power production observed when gas input prices increase from 0.6 to 2.0 NOK/Sm^3 from 2004 to 2006.

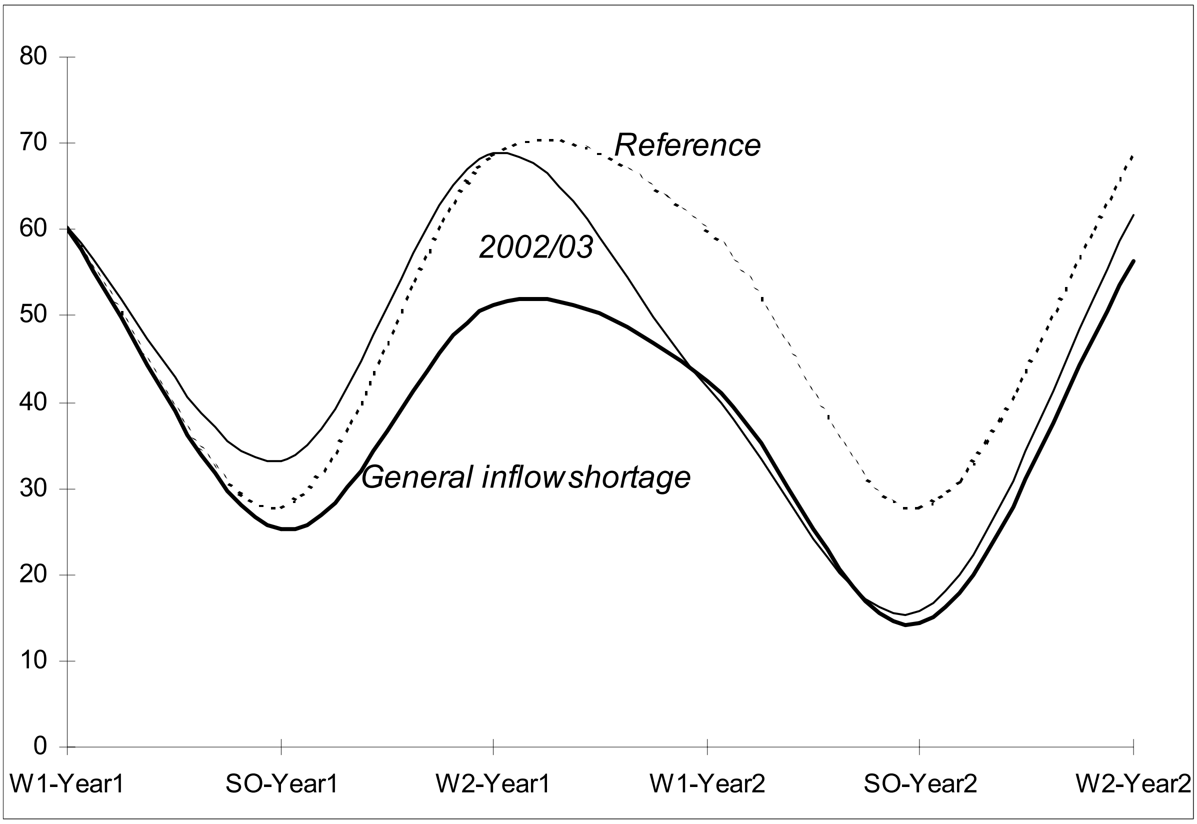
4.1.1. Low reservoirs

Figure 8 shows the simulated reservoir levels in a normal year[8] and for both the 2002/03 and for the case of a 25 per cent overall reduction. Due to high precipitation at the beginning of the year, the simulated reservoir level at the beginning of the summer of 2002 is 7 per cent higher than normal in the *2002/03 scenario*. The reservoir level decreases rapidly during the dry summer and autumn.

In the *General inflow shortage scenario*, the difference to normal increases steadily all through *Year 1*. Despite a significantly lower inflow in the *General inflow shortage scenario*, the reservoir level is about the same in the two shortage scenarios at the beginning of *Year 2*. This follows from a combination of four elements in the *2002/03 scenario*: i) inflow is higher in the spring and the expectations about the autumn are normal, thus production in the spring and the summer are higher to avoid overflow with the autumn rains, ii) a significant fall in autumn inflow, iii) the *average* inflow expectation during the autumn is much higher than realized, hence prices are higher, and a higher production level follows, and iv) lower snow melting due to a deeper fall in precipitation in the last season in *Year 1*.

[8] A normal year is the average annual inflow to the existing reservoirs calculated over a 30-year period. The average annual inflow is 119 TWh. 1 USD = 6.2 NOK.

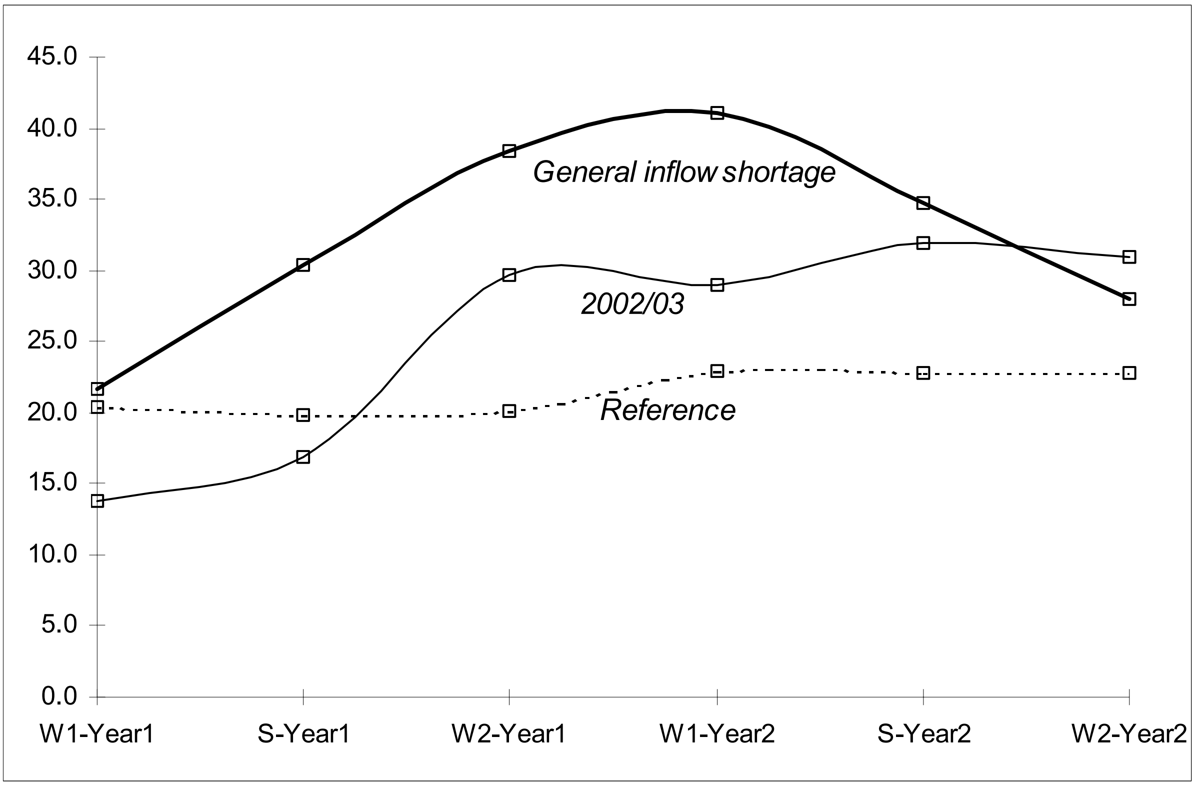
Figure 8. Reservoir levels at the beginning of each period, TWh. Three scenarios



4.1.2. Significantly higher prices than in 2002 and 2003

Figure 9 shows the average seasonal prices in the three scenarios. In *Year 1* in the *2002/03 scenario*, prices are below normal (the *Reference scenario*) due to the higher than normal spring inflow. Then prices rise towards the peak in the winter and end up being more than 50 per cent higher than normal, 30 Nøre/kWh. In the *General shortage scenario*, prices start to increase in the first season and peak at about 40 Nøre/KWh as a seasonal average in *Winter 1* in *Year 2*, i.e., 100 per cent above the normal, and 35 per cent above the 2002/03 peak level. While the price increase is sudden in the *2002/03 scenario*, the price increase in the *General inflow shortage scenario* is more even, which follows the smooth strengthening of the inflow constraint and partial market tightening. When precipitation and inflow return to normal, the prices in the two scenarios approach, but still remain at approximately 50 per cent above the normal level. The slight price increase in the *Reference scenario* is due to a general tightening of the market as demand increase and fewer investments add to production capacity.

Figure 9. Prices, Nøre[1)]/KWh. Three scenarios



[1)] Nøre = 1/100 NOK = 1/620 USD

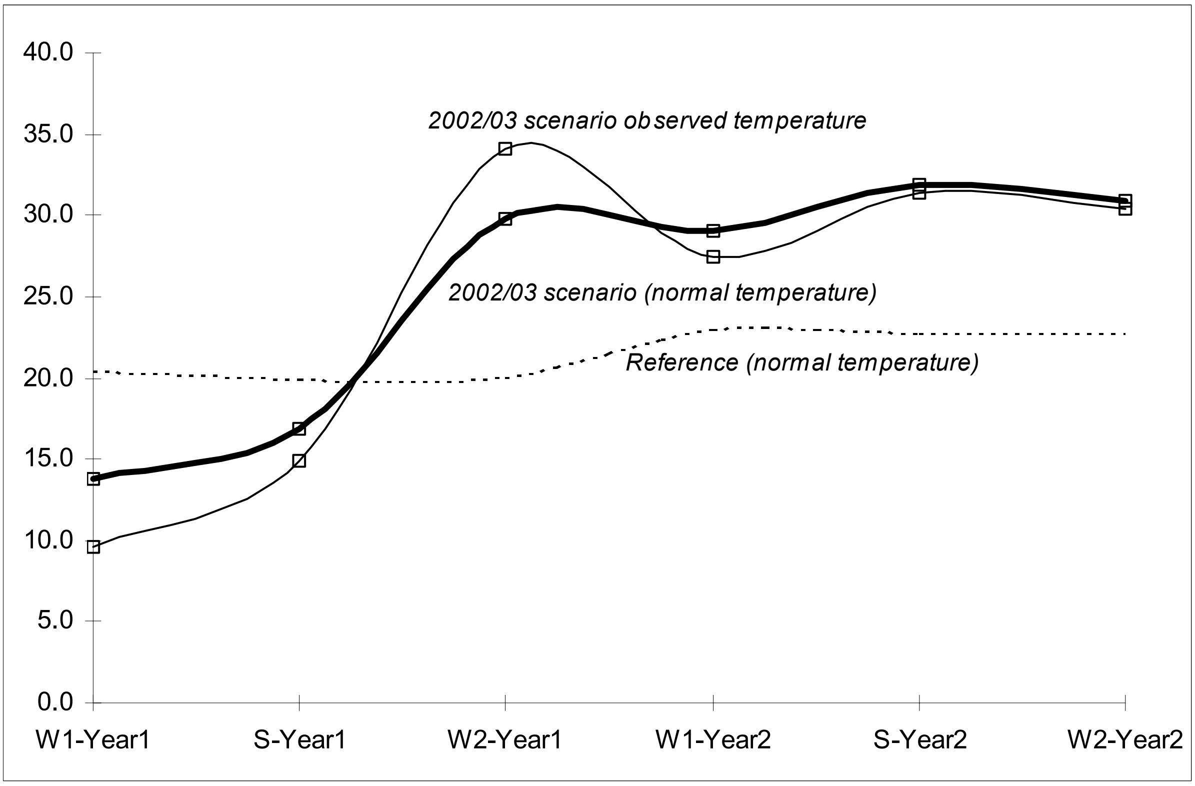
As shown in Figure 6, average actual prices quadrupled and reached 80 Nøre/KWh in most of the Norwegian market during late winter 2002 and early winter 2003. Certainly, this attracted attention from the market, politicians and the public. However, such peaks were few, and the average level through the winter was significantly lower at around 35 Nøre/KWh. Prices fell somewhat from late 2002 throughout 2003, however, the average 2002 price was almost normal (i.e., slightly above 20 Nøre/KWh), while the average price in 2003 was slightly below 30 Nøre/KWh. Even though the power price increase was limited, the purchaser price and cost increase was large for some consumers, since power firms increased the mark-up for different contracts for a period of time.

The actual observed price variation was some 5 Nøre/KWh larger in 2002/03 than that captured by our model simulations. One reason is that the autumn and late winter of 2002 was relatively colder,[9] while the summer was relatively warmer. Temperature variation then contributed to lower prices during the summer of 2002, and to increased prices the following winter. Figure 10 depicts simulated prices with

[9] The temperature was assumed to be normal in our simulations because of comparison to the general inflow shortage scenario.

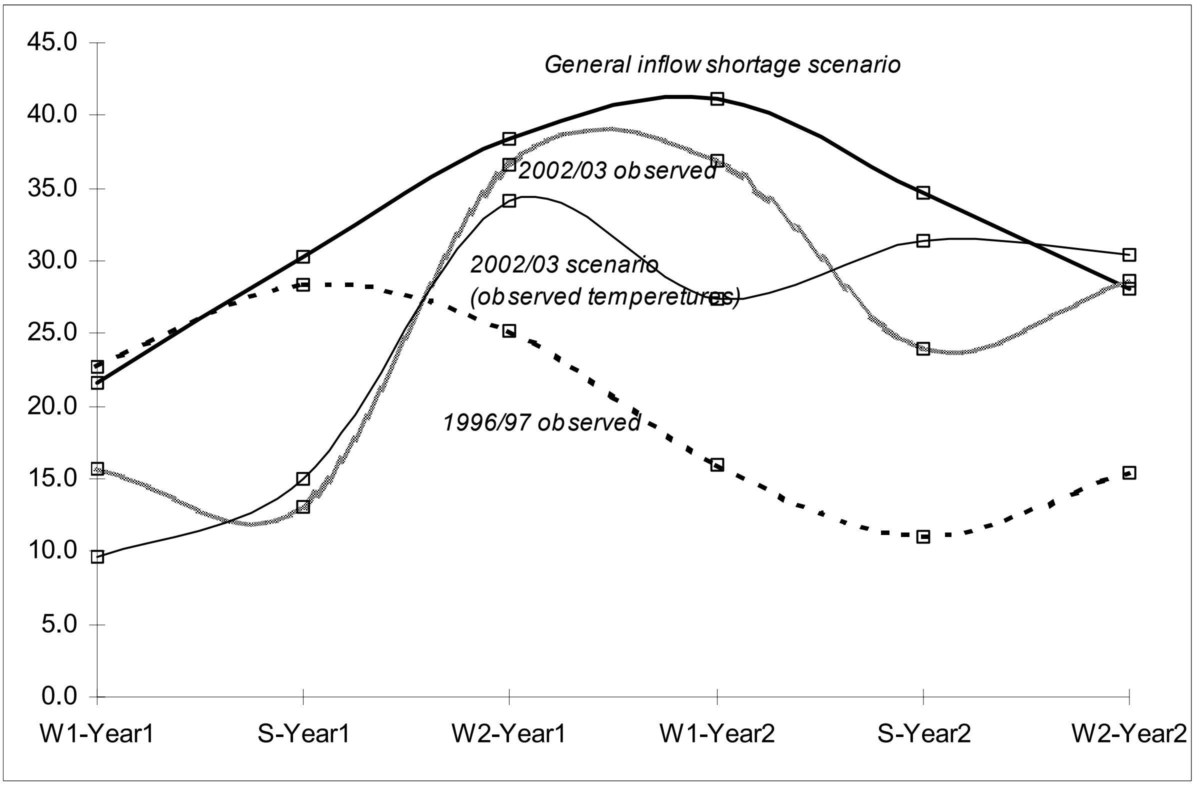
the same inflow assumptions as in the *2002/03 scenario*, but at actual temperatures, compared to the *2002/03 scenario*, based on normal temperatures. The simulated temperature effect increases the price by 15 per cent at the most, i.e., a level comparable to the actual observed average for the season.

Figure 10. Prices given observed temperatures in 2002 and 2003, compared to the *2002/03 scenario* and the *Reference scenario* with normal temperatures, Nøre/KWh



In Figure 11, we compare the simulated price for 2002/03 at observed temperature and the *General inflow shortage scenario* with observed prices in the shortage years 2002/03 and 1996/97. In 1996, the shortage was 20 per cent, with two dry seasons, while the inflow in the last season was above normal.

Figure 11. Observed and simulated prices, different inflow scenarios, Nøre/KWh



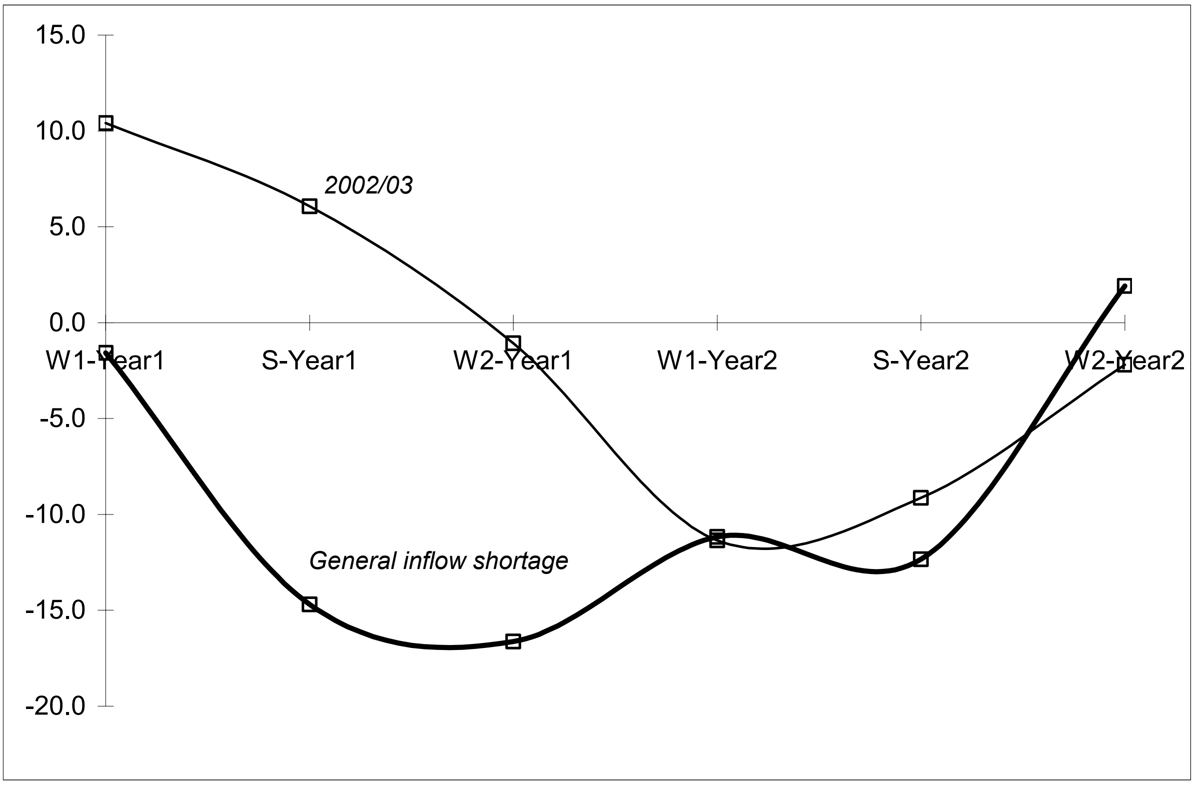
The model captures the main developments in observed prices during both 2002/03 and 1996. There are some discrepancies in the development pattern of the observed and simulated price movements in late *Year 2* of the 2002/03 events. Average prices over the year are comparable, but the simulated fluctuation leads compared to the observed. The model appears to react faster to sharp short-term changes in inflow than the actual market. One possible factor may an overestimation of the mark-up in thermal capacities when inflow changes rapidly. We tested for a non-linear mark-up element, but a square and cubic element turned out to be insignificant (Bye and Hansen, 2006).

In 1996, the inflow shortages in the first two seasons were approximately 30 per cent, i.e., almost comparable to our general shortage scenario, and prices are also almost comparable. In autumn 1996, inflow was approximately 10 per cent higher than normal, i.e., prices started to fall and continued to fall in 1997 when inflow to the system was 15 per cent higher than normal in the first seasons. In our *General shortage scenario*, prices continued to increase until inflow turned normal in year 2. The sharp decrease in prices in the autumn of 1996 and in 1997 could be due to the earlier excess capacity, as explained in Chapter 2.

4.1.3. Production drops as precipitation fails

In the *2002/03 scenario*, production increases in line with the increase in inflow in *Winter 1* in the beginning of the simulation (Figure 12). As accumulated snow, and hence melting during summer, is higher, production remains relatively high. If this were not the case, producers could face overflow if rainfall was at or above normal through the autumn rains. A low inflow during the autumn of 2002 results in increasing deviation in production towards the next spring.

Figure 12. Changes in Norwegian hydro power production, per cent



In the *General inflow shortage scenario*, production starts out slightly lower than normal. Even though the realized inflow shortage is 25 per cent in *Winter 1*, the *average annual* expectation is only 10 per cent lower than normal (Table 1). Hence, production is only reduced at the margin at the beginning of the year. As the inflow loss accumulates over the seasons, production is reduced more drastically. In *Summer*, the accumulated snow was 25 per cent lower than normal, and the *expected annual* shortage 18 per cent, and up to 23 per cent during the *Winter 2*. Still, the reduction in production at the end of *Year 1* levels out at 15 per cent, which is a much lower reduction than the fall in inflow. This contributes to keeping prices relatively low during this period.

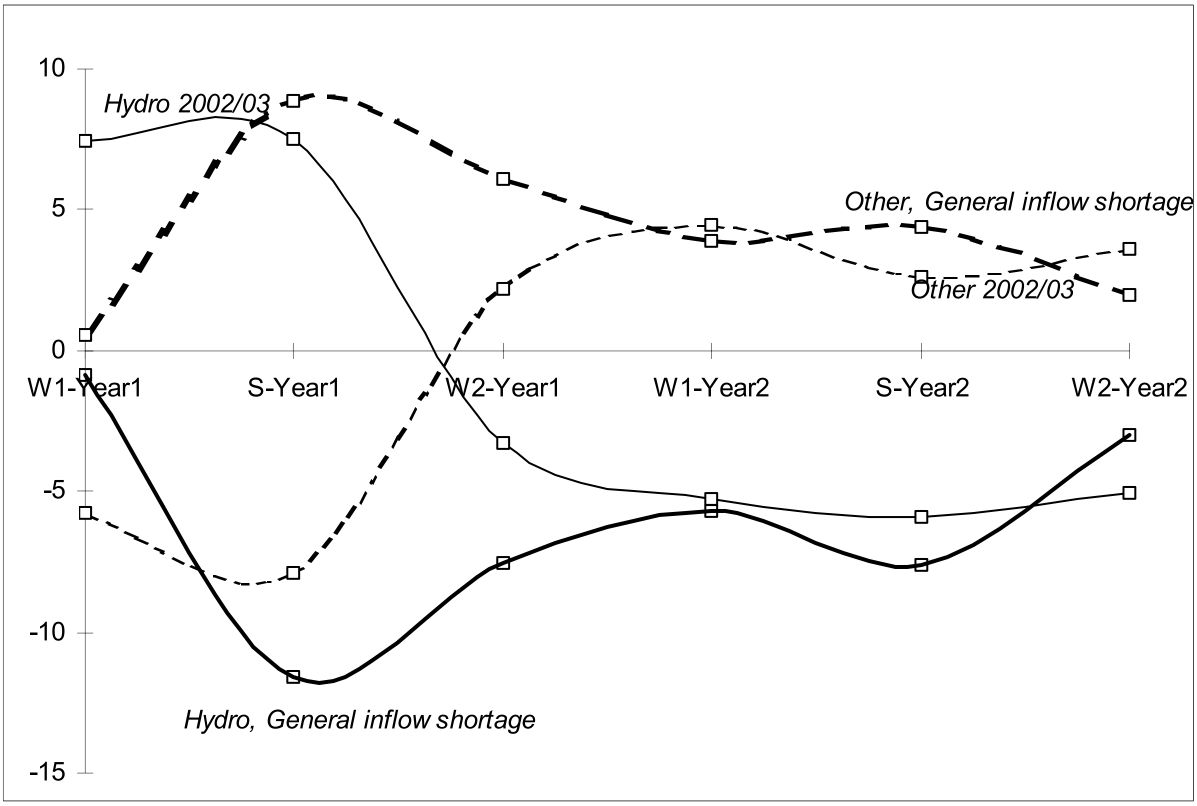
In the second year, precipitation regains in both scenarios, but the reservoir levels drain due to lack of snow melting. Hence, production is withheld, and remains 10–15 per cent lower for the two first seasons.

4.1.4. Trade in the common Nordic market levels off the effects

The market compensates for lower inflows by substitution on the supply side and the reduction in demand, both following increasing power prices. Figure 13 depicts the supply-side substitution.

In the high inflow period during the first seasons in *Year 1* in the *2002/03 scenario*, thermal plants in the Nordic and third-party area deliver less electricity than normal to the Nordic area. This switches around during autumn, and thermal plants assist when inflow fails. This continues throughout *Year 2*, i.e., thermal plants and imports to the hydro-dominated countries in Norway and to a lesser degree Sweden, help fill the reservoirs. In the *General inflow shortage scenario*, thermal production exceeds normal for all periods, mostly when accumulated inflow shortage hits the turning point during *Summer* and *Winter 2* in *Year 1*.

Figure 13. Changes in Nordic power supply, TWh



In both instances, substitution on the supply side only partly compensates for the inflow shortages. Increasing the marginal cost of short-term capacity utilization marks up thermal capacity, and transmission constraints increase electricity prices and reduce demand. Besides, the median reservoir filling varies between a high 90 per cent during the autumn rainfall to a low 35 per cent during the spring before melting starts. The 'absolute' low level sufficient for regulation rules is 8–10 per cent, according to the transmission system operator in Norway. In 2002/03, the low filling hit 18 per cent, as the high prices made it profitable to run a lower minimum reservoir level. As prices are higher in the *General inflow shortage* scenario, it is profitable to run even lower.

4.1.5. The Norwegian market is most exposed, and demand most flexible

Among the Nordic countries, Norway is the most vulnerable to inflow shortage. Virtually 100 per cent of supply is based on hydropower capacity. Norwegian hydropower capacity constitutes 60 per cent of the total hydropower capacity in the region. Regardless, less than half of the thermal-based increase in the Nordic market is consumed in Norway in the two scenarios. This reflects the fact that with some loads, Norway will export, while with other loads, transmission constraints will not allow further imports. One important explanatory factor may also be differences in demand elasticities among countries. According to Bye and Hansen (2006), demand flexibility is higher in Norway than in other Nordic countries. This reflects both technical substitution and the composition of price contracts (both fixed and spot). We also note that in the excess inflow situation in *Winter 1* in the *2002/03 scenario*, only half of the increased inflow generates electricity exports. The rest was consumed domestically.

Figure 14. Net export of power to Norway, TWh

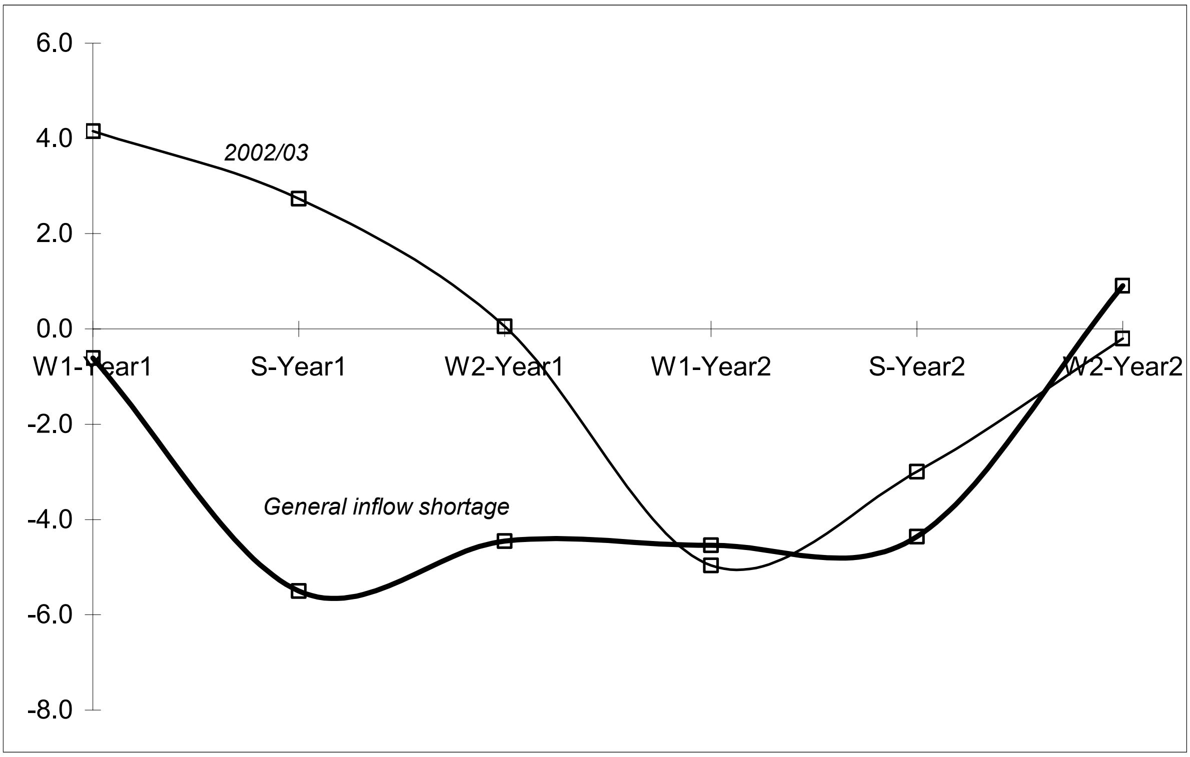
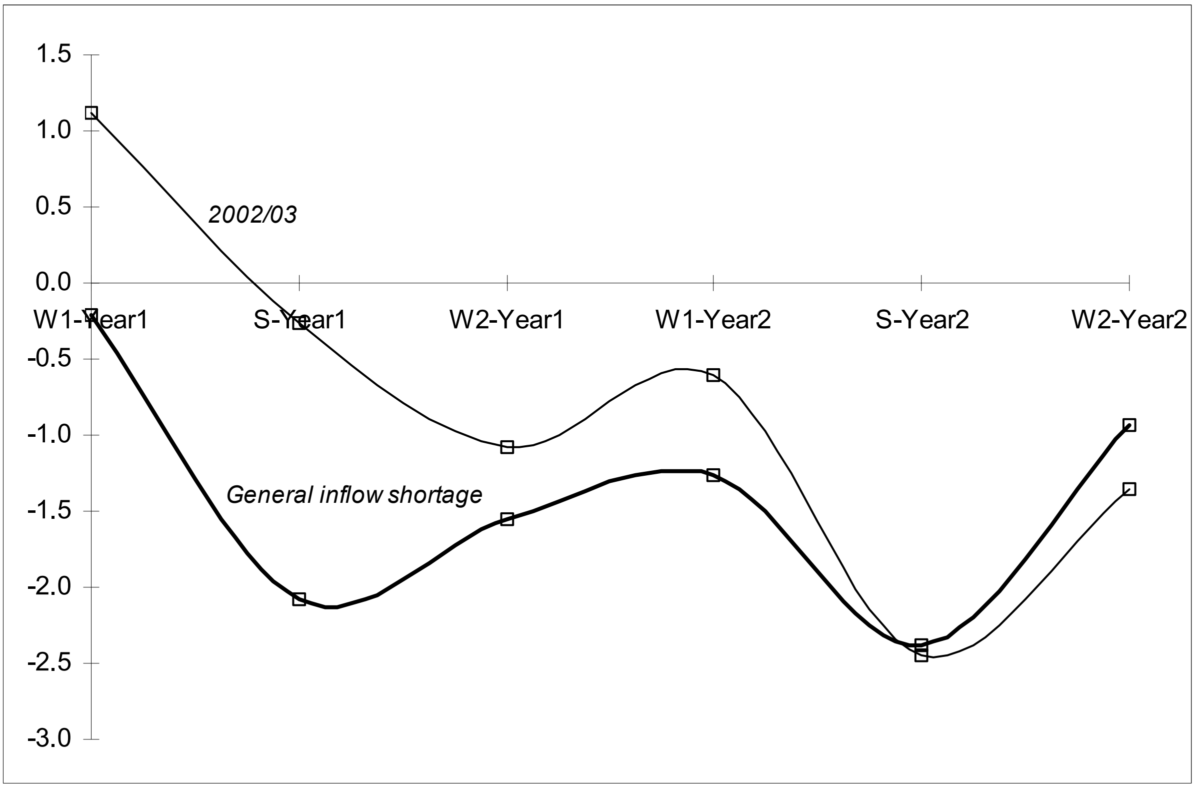


Figure 15 shows the demand responses relative to the *Reference scenario* in the two inflow shortage scenarios. In *2002/03 scenario*, demand increases at the beginning of *Year 1*, due to high inflow and decreasing prices, while it starts falling through the autumn and winter, mirroring the increasing prices during the autumn. In the *General inflow shortage scenario*, demand falls slightly already in summer, due to the steady fall in precipitation that led to increasing prices. While demand picks up rather quickly after precipitation returns to normal in the *General inflow shortage scenario*, it continues to fall in the 2002/03 scenario. Both scenarios eventually approach each other since the scenario prices also approach each other.

Figure 15. Changes in demand compared to reference, per cent



5. Summary

Only one or two decades ago, power markets around the world were regulated. Regulation involved excess capacity in economic terms: a high level of energy supply security funded low rates of return. This turned out to be costly, and investment in production capacity did not follow increases in demand. This continued long after power markets were deregulated.

Many power markets are volatile with respect to supply, because of a higher reliance on hydropower capacity. Decreasing investment in new capacity has increased vulnerability, and questions have been raised about the security of supply in deregulated power markets. Hydropower constitutes some 55 per cent of total supply capacity in the Nordic market. In 2002, the Nordic power market faced an extraordinary short-term shortage of inflow to the hydro reservoirs. The inflow shortage severely impacted upon prices, which escalated for a short period in 2002/03. This increased the focus on security of supply issues, market failures and questions about deregulated markets and sufficient investment in new capacity.

The 2002/03 autumn inflow shortages were a 0.5 probability incident in stochastic inflow measures. The inflow over the last three months was 60 per cent below the normal. However, measured in annual averages, the inflow shortage was only 6 per cent. A 90 per cent confidence interval for inflow variation captures annual variations of ± 25 per cent inflow compared to normal, i.e., the market may face more severe inflow shortages than the one experienced in 2002/03. As late as 1996, the annual inflow was 20 per cent below normal, but at that time, excess capacity existed, and the deregulated market was immature. In this paper, we analysed possible market consequences from a general inflow shortage of 25 per cent in a fully deregulated and mature market with no normal excess capacity, and compared this scenario with a simulated scenario of the 2002/03 event, which offers comparable results.

Although the inflow shortage in our general inflow shortage scenario is more severe than the inflow shortage in 2002/03, equilibrium prices show a modest increase compared to that event. The reasons are threefold. When shortages in inflow are evenly distributed, the market adjusts over a longer period, both with respect to substitution on the supply side and the demand responses, while the allocation of water helps level the effects. The 2002/03 event had some special characteristics that made adjustments slower and more difficult to overcome: a high level of reservoir filling with increasing prices just before the shortage period called for a high production level, and the shortage took place just before the heating season, occurred very fast and was very large in a short-term context.

The Nordic power market, connected to a third-party country market by transmission lines, is relatively flexible with respect to the substitution between hydropower and thermal capacity. Even though there is increasing marginal cost in capacity utilization in the thermal system, and large inflow shortages may cause capacity constraints, the price effects must be characterized as modest, as they are assisted by adjustments in demand. It is likely that when a deregulated market is challenged by inflow shortages, the short-term price increases, along with changed expectations, may enhance the profitability of new investment in production capacity and demand flexibility. Thus, in the future, the flexibility in the system may increase due to the 2002/03 event and focus on the inflow variation.

References

Aune F. R. (2003): Scenarios for the power market until 2020. The effect of increased foreign exchange transmission facilities and enforced gas power plant capacity extension. (in Norwegian). Report 2003/11, Statistics Norway.

Aune, F. R., T. A. Johnsen and A. Vik (2000a): The Norwegian electricity market. Is there enough generation capacity today and will there be sufficient capacity in coming years? Report 2000/26, Statistics Norway.

Aune, F. R., T. Bye and T. A. Johnsen (2000b): Gas power generation in Norway. Good or bad for the climate? Discussion Paper no. 286, Statistics Norway.

Borenstein, S., J.B. Bushnell and C.R. Knittel (1999): Market power in electricity markets: beyond concentration measures. *Energy Journal* **20** (4), 65-88.

Borenstein, S., J.B. Bushnell and S. Stoft (2000): The competitive effects of transmission capacity in a deregulated electricity market. *Rand Journal of Economics* **31** (2), 294-325.

Borenstein, S., J.B. Bushnell and F. Wollack (2002): Measuring market inefficiencies in California's restructured wholesale electricity market. *American Economic Review* **92** (5), 1376-1405.

BP (2006): Statistical Review of World Energy 2006. *http://www.bp.com./productlanding.do?categoryId=91&contented=707990*

Buschnell, J.B. (2003): A mixed complementary model of hydrothermal electricity competition in the western United States. *Operations Research,* **51** (1), January–February.

Bye (2004): A Nordic energy market under stress. Economic Survey 4/2004, Statistics Norway.

Bye, T. and E. Hope (2005): Deregulation of electricity markets. The Norwegian experience. *Economic and Political Weekly,* Vol XI, no 50, December 10, 2005.

Bye, T. and E. Hope (2006): Electricity market reform. The Norwegian experience. *The Norwegian Competition Authority,* July 2006.

Bye, T. and P. V. Hansen (2006): A simultaneous multi market model for the demand elasticity. An econometric study of Sweden and Norway. Forthcoming Discussion Paper, Statistics Norway.

Bye, T., N.-H. Mørch von der Fehr, C. Riis and L. Sørgaard (2003): Kraft og makt - en analyse av konkurranseforholdene i kraftmarkedet (Electric Power and Power - a study of competition in the power market), Report of an Expert Group appointed by the Norwegian Ministry of Labour and Administration.

CBO (2001): Causes and Lessons of the California Electricity Crisis, September 2001.Congressional Budget Office. http://www.cbo.goc/showdoc.cfm?index=3062&sequence=0

Crampes, C. and M. Moreau (2002): Water resource and power generation. *International Journal of Industrial Organization* **19**, 975-997.

Dubash, N.K. and D. Singh (editors) (2005): Global experience with electricity reform. *Special Issue of the Economic and Political Weekly,* Vol XL no 50, December 10-16. http://www.epw.org.in

ECON (2003): Dry year. The robustness of the power system. What is the problem and what may be done about it? Mimeo 11/03ECON, Oslo 2003.

Førsund, F.R (2005): Hydropower economics. Mimeo, Oslo University, 2005.

Førsund, F.R., R. Golombek, M. Hoel and S.A.C. Kittelsen (2003): The exploitation of hydropower storages. *Report 4/2003, Ragnar Frisch Centre of Economic Research, Oslo 2003*

Jamasb, T., R. Mota, D. Newbery and M. Pollitt (2004): Electricity sector reform in developing countries. A survey of empirical evidence on determinants and performance. *Cambridge Working Papers in Economics CWPE 0439.*

Joskow, P.L. (2001): California's electricity crisis. *NBER Working Paper 8442. http://www.nber.org/papers/w8442*

Joskow, P.L. and R. Schmalense (1983): Markets for power: An analysis of electric utility deregulation. *MIT Press, Cambridge, Massachusetts, USA.*

Pollitt, M.G. (2004): Electricity reform in Chile: Lessons for developing countries, *Journal of Network Industries* **5** (3-4), 221-262.

Martinek, J.P and M.J. Orlando (2002): Neither Lucky Nor Good: The Case of Electricity Deregulation in California. *The Economic and Social Review,* **33** (1), 75-82.

Newbery, D. (editor) (2005): European electricity liberalization. *Special Issue of the Energy Journal, 2005.*

Wollack, F. (2003): Diagnosing the California electricity crisis, *The Electricity Journal,* **16** (7), 11-37.

Recent publications in the series Discussion Papers

380 A. Langørgen and D. Rønningen (2004): Local government preferences, individual needs, and the allocation of social assistance

381 K. Telle (2004): Effects of inspections on plants' regulatory and environmental performance - evidence from Norwegian manufacturing industries

382 T. A. Galloway (2004): To What Extent Is a Transition into Employment Associated with an Exit from Poverty

383 J. F. Bjørnstad and E.Ytterstad (2004): Two-Stage Sampling from a Prediction Point of View

384 A. Bruvoll and T. Fæhn (2004): Transboundary environmental policy effects: Markets and emission leakages

385 P.V. Hansen and L. Lindholt (2004): The market power of OPEC 1973-2001

386 N. Keilman and D. Q. Pham (2004): Empirical errors and predicted errors in fertility, mortality and migration forecasts in the European Economic Area

387 G. H. Bjertnæs and T. Fæhn (2004): Energy Taxation in a Small, Open Economy: Efficiency Gains under Political Restraints

388 J.K. Dagsvik and S. Strøm (2004): Sectoral Labor Supply, Choice Restrictions and Functional Form

389 B. Halvorsen (2004): Effects of norms, warm-glow and time use on household recycling

390 I. Aslaksen and T. Synnestvedt (2004): Are the Dixit-Pindyck and the Arrow-Fisher-Henry-Hanemann Option Values Equivalent?

391 G. H. Bjønnes, D. Rime and H. O.Aa. Solheim (2004): Liquidity provision in the overnight foreign exchange market

392 T. Åvitsland and J. Aasness (2004): Combining CGE and microsimulation models: Effects on equality of VAT reforms

393 M. Greaker and Eirik. Sagen (2004): Explaining experience curves for LNG liquefaction costs: Competition matter more than learning

394 K. Telle, I. Aslaksen and T. Synnestvedt (2004): "It pays to be green" - a premature conclusion?

395 T. Harding, H. O. Aa. Solheim and A. Benedictow (2004). House ownership and taxes

396 E. Holmøy and B. Strøm (2004): The Social Cost of Government Spending in an Economy with Large Tax Distortions: A CGE Decomposition for Norway

397 T. Hægeland, O. Raaum and K.G. Salvanes (2004): Pupil achievement, school resources and family background

398 I. Aslaksen, B. Natvig and I. Nordal (2004): Environmental risk and the precautionary principle: “Late lessons from early warnings” applied to genetically modified plants

399 J. Møen (2004): When subsidized R&D-firms fail, do they still stimulate growth? Tracing knowledge by following employees across firms

400 B. Halvorsen and Runa Nesbakken (2004): Accounting for differences in choice opportunities in analyses of energy expenditure data

401 T.J. Klette and A. Raknerud (2004): Heterogeneity, productivity and selection: An empirical study of Norwegian manufacturing firms

402 R. Aaberge (2005): Asymptotic Distribution Theory of Empirical Rank-dependent Measures of Inequality

403 F.R. Aune, S. Kverndokk, L. Lindholt and K.E. Rosendahl (2005): Profitability of different instruments in international climate policies

404 Z. Jia (2005): Labor Supply of Retiring Couples and Heterogeneity in Household Decision-Making Structure

405 Z. Jia (2005): Retirement Behavior of Working Couples in Norway. A Dynamic Programming Approch

406 Z. Jia (2005): Spousal Influence on Early Retirement Behavior

407 P. Frenger (2005): The elasticity of substitution of superlative price indices

408 M. Mogstad, A. Langørgen and R. Aaberge (2005): Region-specific versus Country-specific Poverty Lines in Analysis of Poverty

409 J.K. Dagsvik (2005) Choice under Uncertainty and Bounded Rationality

410 T. Fæhn, A.G. Gómez-Plana and S. Kverndokk (2005): Can a carbon permit system reduce Spanish unemployment?

411 J. Larsson and K. Telle (2005): Consequences of the IPPC-directive’s BAT requirements for abatement costs and emissions

412 R. Aaberge, S. Bjerve and K. Doksum (2005): Modeling Concentration and Dispersion in Multiple Regression

413 E. Holmøy and K.M. Heide (2005): Is Norway immune to Dutch Disease? CGE Estimates of Sustainable Wage Growth and De-industrialisation

414 K.R. Wangen (2005): An Expenditure Based Estimate of Britain's Black Economy Revisited

415 A. Mathiassen (2005): A Statistical Model for Simple, Fast and Reliable Measurement of Poverty

416 F.R. Aune, S. Glomsrød, L. Lindholt and K.E. Rosendahl: Are high oil prices profitable for OPEC in the long run?

417 D. Fredriksen, K.M. Heide, E. Holmøy and I.F. Solli (2005): Macroeconomic effects of proposed pension reforms in Norway

418 D. Fredriksen and N.M. Stølen (2005): Effects of demographic development, labour supply and pension reforms on the future pension burden

419 A. Alstadsæter, A-S. Kolm and B. Larsen (2005): Tax Effects on Unemployment and the Choice of Educational Type

420 E. Biørn (2005): Constructing Panel Data Estimators by Aggregation: A General Moment Estimator and a Suggested Synthesis

421 J. Bjørnstad (2005): Non-Bayesian Multiple Imputation

422 H. Hungnes (2005): Identifying Structural Breaks in Cointegrated VAR Models

423 H. C. Bjørnland and H. Hungnes (2005): The commodity currency puzzle

424 F. Carlsen, B. Langset and J. Rattsø (2005): The relationship between firm mobility and tax level: Empirical evidence of fiscal competition between local governments

425 T. Harding and J. Rattsø (2005): The barrier model of productivity growth: South Africa

426 E. Holmøy (2005): The Anatomy of Electricity Demand: A CGE Decomposition for Norway

427 T.K.M. Beatty, E. Røed Larsen and D.E. Sommervoll (2005): Measuring the Price of Housing Consumption for Owners in the CPI

428 E. Røed Larsen (2005): Distributional Effects of Environmental Taxes on Transportation: Evidence from Engel Curves in the United States

429 P. Boug, Å. Cappelen and T. Eika (2005): Exchange Rate Rass-through in a Small Open Economy: The Importance of the Distribution Sector

430 K. Gabrielsen, T. Bye and F.R. Aune (2005): Climate change- lower electricity prices and increasing demand. An application to the Nordic Countries

431 J.K. Dagsvik, S. Strøm and Z. Jia: Utility of Income as a Random Function: Behavioral Characterization and Empirical Evidence

432 G.H. Bjertnæs (2005): Avioding Adverse Employment Effects from Energy Taxation: What does it cost?

433. T. Bye and E. Hope (2005): Deregulation of electricity markets—The Norwegian experience

434 P.J. Lambert and T.O. Thoresen (2005): Base independence in the analysis of tax policy effects: with an application to Norway 1992-2004

435 M. Rege, K. Telle and M. Votruba (2005): The Effect of Plant Downsizing on Disability Pension Utilization

436 J. Hovi and B. Holtsmark (2005): Cap-and-Trade or Carbon Taxes? The Effects of Non-Compliance and the Feasibility of Enforcement

437 R. Aaberge, S. Bjerve and K. Doksum (2005): Decomposition of Rank-Dependent Measures of Inequality by Subgroups

438 B. Holtsmark (2005): Global per capita CO_2 emissions - stable in the long run?

439 E. Halvorsen and T.O. Thoresen (2005): The relationship between altruism and equal sharing. Evidence from inter vivos transfer behavior

440 L-C. Zhang and I. Thomsen (2005): A prediction approach to sampling design

441 Ø.A. Nilsen, A. Raknerud, M. Rybalka and T. Skjerpen (2005): Lumpy Investments, Factor Adjustments and Productivity

442 R. Golombek and A. Raknerud (2005): Exit Dynamics with Adjustment Costs

443 G. Liu, T. Skjerpen, A. Rygh Swensen and K. Telle (2006): Unit Roots, Polynomial Transformations and the Environmental Kuznets Curve

444 G. Liu (2006): A Behavioral Model of Work-trip Mode Choice in Shanghai

445 E. Lund Sagen and M. Tsygankova (2006): Russian Natural Gas Exports to Europe. Effects of Russian gas market reforms and the rising market power of Gazprom

446 T. Ericson (2006): Households' self-selection of a dynamic electricity tariff

447 G. Liu (2006): A causality analysis on GDP and air emissions in Norway

448 M. Greaker and K.E. Rosendahl (2006): Strategic Climate Policy in Small, Open Economies

449 R. Aaberge, U. Colombino and T. Wennemo (2006): Evaluating Alternative Representation of the Choice Sets in Models of Labour Supply

450 T. Kornstad and T.O. Thoresen (2006): Effects of Family Policy Reforms in Norway. Results from a Joint Labor Supply and Child Care Choice Microsimulation Analysis

451 P. Frenger (2006): The substitution bias of the consumer price index

452 B. Halvorsen (2006): When can micro properties be used to predict aggregate demand?

453 J.K. Dagsvik, T. Korntad and T. Skjerpen (2006): Analysis of the disgouraged worker phenomenon. Evidence from micro data

454 G. Liu (2006): On Nash equilibrium in prices in an oligopolistic market with demand characterized by a nested multinomial logit model and multiproduct firm as nest

455 F. Schroyen and J. Aasness (2006): Marginal indirect tax reform analysis with merit good arguments and environmental concerns: Norway, 1999

456 L-C Zhang (2006): On some common practices of systematic sampling

457 Å. Cappelen (2006): Differences in Learning and Inequality

458 T. Borgersen, D.E. Sommervoll and T. Wennemo (2006): Endogenous Housing Market Cycles

459 G.H. Bjertnæs (2006): Income Taxation, Tuition Subsidies, and Choice of Occupation

460 P. Boug, Å. Cappelen and A.R. Swensen (2006): The New Keynesian Phillips Curve for a Small Open Economy

461 T. Ericson (2006): Time-differentiated pricing and direct load control of residential electricity consumption

462 T. Bye, E. Holmøy and K. M. Heide (2006): Removing policy based comparative advantage for energy intensive production. Necessary adjustments of the real exchange rate and industry structure

463 R. Bjørnstad and R. Nymoen (2006): Will it float? The New Keynesian Phillips curve tested on OECD panel data

464 K.M.Heide, E. Holmøy, I. F. Solli and B. Strøm (2006): A welfare state funded by nature and OPEC. A guided tour on Norway's path from an exceptionally impressive to an exceptionally strained fiscal position

465 J.K. Dagsvik (2006): Axiomatization of Stochastic Models for Choice under Uncertainty

466 S. Hol (2006): The influence of the business cycle on bankruptcy probability

467 E. Røed Larsen and D.E. Sommervoll (2006): The Impact on Rent from Tenant and Landlord Characteristics and Interaction

468 Suzan Hol and Nico van der Wijst (2006): The financing structure of non-listed firms

469 Suzan Hol (2006): Determinants of long-term interest rates in the Scandinavian countries

470 R. Bjørnstad and K. Øren Kalstad (2006): Increased Price Markup from Union Coordination - OECD Panel Evidence.

471 E. Holmøy (2006): Real appreciation as an automatic channel for redistribution of increased government non-tax revenue.

472 T. Bye, A. Bruvoll and F.R. Aune (2006): The importance of volatility in inflow in a deregulated hydro-dominated power market.