Discussion Papers No. 430, August 2005
Statistics Norway, Research Department

Karina Gabrielsen, Torstein Bye and Finn Roar Aune

Climate change- lower electricity prices and increasing demand
An application to the Nordic Countries

Abstract:
Concentration of greenhouse gases in the atmosphere influences the climate, which then alters the amount of primary energy for countries or regions where hydropower and wind power constitute important parts of the energy supply. Besides, the demand effect of temperature increases may be large in economies where heating and air-conditioning demand a large share of total energy. In this article, we apply climate change calculations from natural science and detailed inflow data from the authorities to estimate the change in primary energy supply of the hydropower-dominated Nordic electricity market. The estimated inflow model shows an increase in primary inflow in the next 40 years of 6–15% in the Nordic countries. An estimated temperature model shows a 2–4% initial drop in demand in the same time period, because of increasing temperature. Within the context of a perfect-competition electricity market model, we simulate the total market outcome. As primary supply increases, the production cost decreases, prices drop and the total demand increases as the price effect dominates the temperature effect. Since the hydropower plants are located away from large consumer groups, the stress on the transmission networks is dramatic for some regions, which in the next phase may trigger new investments in transmission network capacities.

Keywords: Climate change, electricity market

JEL classification: q11,q21,q42

Acknowledgement: Thanks to J.E. Haugen at DNMI for valuable help on the RegClim data.

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

Karina Gabrielsen, Msc, Statistics Norway, Research Department.
E-mail: gab @ssb.no

Finn Roar Aune, Senior A, 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

Introduction

Concentration of greenhouse gases in the atmosphere influences the climate, i.e., temperature, wind, rain, snow, etc. Climate changes then alter the amount of primary energy for countries or regions where hydropower and wind power constitute important parts of the energy supply. Increasing temperature also influences energy demand because of less need for heating or more demand for cooling. In this article, we estimate the simultaneous climate change and electricity market effect in a regionalized, hydropower-dominated electricity market. Since most energy demand is located a long way from the primary energy supply (waterfalls and wind), climate change may stress the transmission network system and thus alter the requirement for investment in new transmission capacity. To our knowledge, nobody in the literature seems to have integrated the climate issue and the electricity market effects in a simultaneous energy market model.

A large literature from the natural sciences looks into the relationship between emissions, climate change and important supply-side effects in power systems based on hydro energy, wind energy, solar energy etc; see, for example, Bergström, Andrèasson et al. (2003), Kuusisto (2004) and Beldring, Roald et al. (2005) for some recent studies. The Swedish Meteorological and Hydrological Institute (SMHI) has developed a Water Balance Model that is used in more than 40 countries all over the world, see Bergström (1976) and Bergström, Harlin et al. (1992). The model is very detailed at the water catchments scale, with hourly or daily observations, and includes precipitation, snow balance, temperature, evaporation, runoff, and subbasins and lakes. Kaczmarek, Somlyòdy et al. (1996) document the so-called “delta change” approach, which transforms the climate change variables to hydrological models. Several other studies like Lemmelä and Helenius (eds.) (1998), Lettenmaier, Wood et al. (1999), and Reynard, Prudhomme et al. (2001) offer variations on the same subject. For a full reference list, see Bergström, Andrèasson et al. (2003). Examples of other models on the same subject are the IRMB model (Gellens and Roulin, 1998), the CLASSIC model (Reynard, Prudhomme et al., 2001), the ARC/EGMO model (Müller-Wohlfeil, Bürger et al., 2000) and the HSPF model (Middelkoop, Daamen et al. 2001).

In our article, we address the climate change effect on important explanatory variables for estimating the inflow and wind, the supply effect on hydropower and wind power capacity, and the electricity market impact. Our climate model does include the same variables as the SMHI water balance model, however it is slightly refined since it operates on a regional and seasonal level, see Gabrielsen (2005) and Beldring, Engeland et al. (2003). Our model produces comparable results for the hydrological balance in the reservoirs, which is suitable for the linkage of the climate model and the electricity market model.

The RegClim project in Norway and the SWECLIM project in Sweden, (Bergström, Andrèasson et al., 2003), which study the relationship between emission of greenhouse gases and important climate change indicators, constitute important inputs to our study. The starting point is the climate scenario ECHAM/OPYC3 (Bjørge, Haugen et al., 2000), which relies heavily on the emission scenario IS92a from The Intergovernmental Panel of Climate Change (IPCC). This emission scenario indicates a 1% increase in the emissions of greenhouse gases per year from 1990 until 2050 (IPCC, 2000). RegClim has developed a regional climate scenario based on dynamic downscaling of ECHAM/OPYC3, HIRHAM (RegClim. 2, 2002). Based on climate variables from this scenario and observed inflow series to the hydropower system, we estimate a supply model for the hydropower and wind power system in the four Nordic countries (Norway, Sweden, Finland and Denmark). The climate scenario also reports on possible outdoor temperature changes, which we combine with estimations of the temperature influence on demand, see Johnsen and Spjeldnæs (2005). We establish an electricity equilibrium market model for these countries (see Johnsen, 1998) and analyze the effect of climate changes on supply, demand, trade and transmission in the Nordic electricity market during the next 40 years.

The rest of the paper is organized as follows. In section 2, we derive the three formal models: the climate model, the temperature model and the electricity market model. In section 3, we discuss the data, and in section 4 we present the empirical results on the estimated climate and temperature model. Section 5 discusses the simulated market effects, and section 6 concludes.

The model

The complete model used in our analyses comprises three elements; a climate model, a temperature model and an electricity market model. The climate model concerns the shifts in primary energy supply due to climate changes. The temperature model looks into the partial demand-side effect of climate change. The electricity market model integrates economic activity, the energy supply-side and demand-side effects, cost-minimizing expansion of production capacity, transmission capacity constraints, and market-clearing mechanisms (perfect competition).

The climate model

The climate model consists of two parts: one part defines the relationship between the development of climate change variables and inflow to the hydropower reservoirs. The second part describes the link between wind speed and production capacities in windmills. In this section, our main focus is on the climate inflow model, while we comment briefly on the wind model at the end of the section.

The inflow model

Water inflow into the hydropower reservoirs is the basis for hydropower production. The inflow varies because of rainy seasons in the spring and the autumn, cold weather and snow accumulation during winter, and snow melting in the spring, etc. We assume that inflow at time t, I_t, is influenced by the direct effect of rain at that time R_t, the runoff into the reservoir, P_t, which may be due to accumulated snow and rain in the surrounding ground. We deduct evaporation E_t, following Bergström, Andrèasson et al. (2003). Our model is linear in the variables:

(1) $$I_t = \beta_0 R_t + \chi_0 P_t - \eta_0 E_t$$

and there is no constant term as there is no inflow without rain and runoff[1]. The runoff is explained by rain as an indicator of the humidity in the soil and snow melting from the storage of snow, S_t.

(2) $$P_t = \nu_0 R_t + \nu_1 S_t$$

In the seasonal pattern of inflow, the effects from snow and rain differ. Rain will contribute to increased inflow with almost no lag, but will depend on the water content of the surrounding soil. The snow needs to melt before it is measured as inflow, i.e., the ν_1 parameter is zero for most of the year except for the melting period. During winter, almost all snow accumulates. When temperature increases in the spring, the snow starts melting. The melting speed is also influenced by the amount of rain during the melting period, i.e., the rain has different impacts on inflow during the melting period and during the rest of the year. If the temperature is high while the weather is rainy, the melting could also become overflow, i.e., all the inflow may not be captured in the reservoirs. According to the data series from RegClim, the typical melting period in Norway and Sweden, which constitutes the largest share of the hydropower capacity in the Nordic countries, is weeks 17–23. To include the effect of snow melting, we create a multiplicative dummy for every week of the average snow-melting period, with a one-week lag. Each dummy accounts for the melting in one particular week in the period. To account for the particular effect of rain on inflow in the snow-melting period, we add multiplicative dummies (D) for rain in the same weeks.

(3) $$v_1 S_t = \kappa_1 S^*{}_t + \sum_{i=17}^{23} \kappa_i S_{t-1} D + \sum_{i=17}^{23} \beta_i R_t D$$

The S_t^* variable accounts for the effect of daily snow directly into the reservoirs. Putting equation (2) and (3) into equation (1) and rearranging and redefining the coefficients results in:

(4) $$I_t = \beta^* R_t + \chi^* S_t^* + \sum_{i=17}^{23} \kappa_i^* S_{t-1} D + \sum_{i=17}^{23} \beta_i^* R_t D - \eta_0 E_t + \varepsilon_t$$

where we have added a normally distributed stochastic term ε_t with a constant variance[2]. Temperature is only included in the inflow model by its effect on rain, snow melting and runoff. If the temperature is high, more snow is melting, but as the ground might be dryer, the inflow can be somewhat reduced.

Wind speed

The production potential for wind power, W_t, depends on the wind speed, WS_t, and the amplitude of the wind. The windmill stops when the wind speed is low, and it also stops when the wind speed is very high, as the load on the mill becomes too high. The RegClim scenarios do not report the change in the wind amplitude as climate changes, but the change in wind speed is calculated. As the wind speed increases, the increased production potential in the windmills is cubed, i.e.:

(5) $$W_t = A_t \left(\frac{WS_t^*}{WS_t^0} \right)^3$$

where A_t, represents all other factors, except wind speed, that define the production capacity in windmills. The windmill capacity is higher during winter than during summer, as the average wind

---

[1] We tested a model with a constant term, but the R^2 of 0.40 was rejected against an R^2 of 0.64 in the model without a constant term.

[2] For comparison, the SMHI model is formulated as: P–E–Q = d/dt SP+SM+UZ+LZ+lakes, where *P* = precipitation, *E* = evapotranspiration, *Q* = runoff, *SP* = snow pack, *SM* = soil moisture, *UZ* = upper groundwater zone, *LZ* =lower groundwater zone, *lakes* = lake volume.

speed is higher. The RegClim scenario also predicts that the wind speed will increase most during winter. This is the time when the capacity utilization of all the power plants and the transmission networks is at its highest, which may be of importance in the market clearing between periods.

The temperature model

Increasing outdoor temperature because of climate changes may influence the demand for electricity in two ways: the need for heating and the need for air-conditioning. The cold climate in the Nordic countries means that a significant part of the electricity consumption concerns heating. A future higher temperature may influence the use of electricity for air-conditioning during summer. Since there is no long history of air-conditioning in the Nordic countries, the possibility of identifying the magnitude of this effect in time series data is meager. The amount of heating varies greatly over the seasons in the Nordic countries. To separate the temperature effect from price effects, economic activity, season, etc. when estimating from historic data, we need a detailed model:

$$E_t = f_t(P_E, P_F, Y, W, D, H) \tag{6}$$

where E_t is the electricity demand, P_E the electricity price, P_F the fuel oil price, and Y is the activity level, W is the wind speed, D is the day length, H is holiday dummies, and HDD is a variable for heating degree-days. Heating degree-days are defined as the sum of the differences between 17 °C and the average daily temperatures for all days colder than 17 °C. Johnsen and Spjeldnæs (2005) estimated such a model based on an error correction model specification, where a change in the natural logarithm of weekly consumption is the dependent variable. The demand for electricity is then:

$$\begin{aligned}
&\Delta\ln(E_t) = \alpha_0 + \alpha_1\Delta\ln(p_t^E) + \alpha_2\Delta\ln(p_t^F) + \alpha_3\Delta\ln(Y_t) + \alpha_4\ln(W_t) + \alpha_5\Delta\ln(D_t) + \\
&\alpha_6\Delta(HDD_t) + \alpha_7\ln(p_{t-1}^E) + \alpha_8\ln(p_{t-1}^F) + \alpha_9\ln(Y_{t-1}) + \alpha_{10}\ln(D_{t-1}) + \alpha_{12}(HDD_{t-1}) + \\
&\alpha_{13}\ln(E_{t-1}) + \mathit{holiday\ dummys}_t + \varepsilon
\end{aligned} \tag{7}$$

The error term, ε, is assumed to be normally distributed with an expected value of zero and constant variance.

Estimations on high-frequency data should take into account the fact that prices of electricity and equilibrium supply and demand are set simultaneously, i.e., prices are not exogenous to the consumer (see Bye and Hansen, 2005). Typically, a high level of demand and high prices are correlated, which intuitively contradicts the theory of a downward-sloping demand curve. Demand shifts upward and downward because of temperature changes, business cycles, etc. The slope of the demand curve may also vary as the substitution possibilities vary with temperature. During winter, more than half of the consumption is related to heating, where fossil fuel or wood stock may be perfect substitutes for electricity. During summer, almost all electricity is related to technical end uses where the substitution possibilities are negligible. The supply curve is increasing in the marginal production, which is typically stepwise in a thermal system.

In a hydropower-dominated system, the water value depends on the marginal cost curve of the alternatives (typically thermal plants). The supply shifts in the short run because of outages, transmission constraints and inflow variability. As both demand and supply shift, we cannot presume that prices are exogenous variables. The price equation may now be formulated as described in Johnsen and Spjeldnæs (2005):

(8) $$\Delta \ln(p_t^E) = \beta_0 + \beta_1 \Delta \ln(E_t) + \beta_2 \ln(E_{t-1}) + \beta_3 \ln(Z_{t-1}) + \beta_4 \ln(p_{t-1}^E) + \varepsilon$$

where Z is the hydrological balance working as an instrument for the increasing marginal cost in production.

In our simulations later on, we will only consider the first-order effects of changing temperatures, i.e., equation (7), which indicates that demand for electricity is reduced when the temperature increases. Equation (8) shows that the price will fall when demand decreases; consequently, prices drop when the temperature increases. In the electricity demand model (7), both effects are accounted for. In our simultaneous approach, the price equation (8) is substituted by the equilibrium price in the detailed electricity market model.

The electricity market model

So far we have discussed the possible implications for the primary energy supply and the isolated temperature effect on electricity demand from climate changes. To analyze the total impact of climate changes on the electricity markets, we need a full market model. As inflow increases, the supply of energy increases at a lower unit cost because of decreasing marginal cost at the plant level. The increasing temperature reduces demand, but this effect will be counteracted by the reduced price. Since waterfalls are rarely located at the demand site, transmission capacity and constraints affect the market equilibrium in a region. To capture all these effects we need a detailed market model.

Such a model is outlined in figure 1. The main exogenous elements are a description of the future economic activity, the existing production and transmission capacities, the marginal cost of expansion of the capacity elements, and the prices in the “third countries” that may possibly influence the Nordic electricity market clearance. The core of the model is the market clearing mechanism equalizing wholesale prices between customers, utilizing the existing capacities, clearing regional prices when transmission capacities are fully used, and expanding capacities when prices exceed long-term marginal cost. This model outline follows Johnsen (1998) and Rogers and Rowse (1989).

The model describes the Norwegian, Swedish, Danish and Finish markets in three seasons (winter 1, summer and winter 2) and four load blocks (peak, high, medium and base load) under the assumption of perfect competition. According to Førland, Roald et al. (2000), the winter season becomes less stable and the pronounced snowmelt peak in runoff is replaced by more evenly distributed runoff during winter in many areas when the climate changes. This clearly calls for a seasonal model capturing the storing possibilities and capacities in a hydropower-dominated area when analyzing the effect of climate changes.

The Nordic area is divided into 14 regions (see figure 2), which are based on the geographical position of the existing power plants and the capacities of the transmission net. The thickness of the lines indicates the capacities of the transmission system between countries in the short run. Norway is divided into eight regions, Sweden into three, Denmark into two, and Finland is one region.

Figure 1: The core of the electricity market model

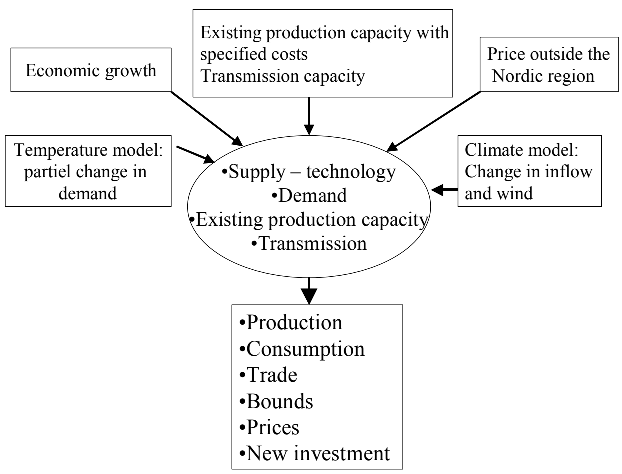
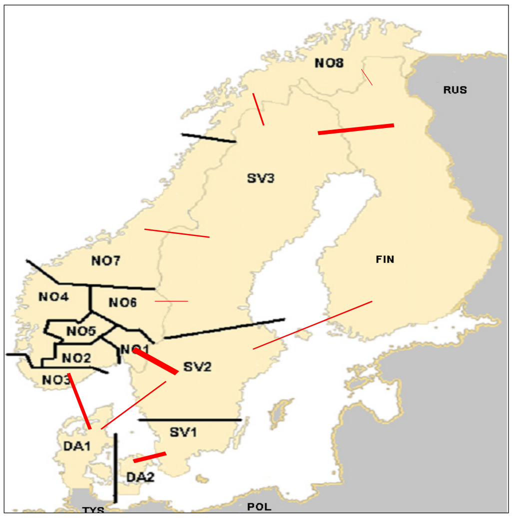


Figure 2: A split of Nordic countries



Demand

The customers in each region are divided into five different segments: metal, pulp and paper, other manufacturing, services and households. This is important for the model solution because of the different demand elasticities and consumption patterns in the regions. The average price elasticity for electricity in the whole area is – 0.3. Over time, the size of different sectors changes, which also changes the aggregate elasticities. Demand for electricity depends on electricity prices and activity level:

(9) $$Z_{sijt} = \beta_{0sijt} + \beta_{1sijt} PC_{sijt} + \beta_{2jt} w_{sijt}$$

where Z_{sijt} is sector j's power demand (MWh) for season s, load period i and country t. The end user price is PC_{sijt} (N.øre/kWh), and w_{sijt} indicates the activity level in each sector. Linear demand equations imply price-dependent elasticities. The end users' electricity purchase price is the sum of a common market wholesale price (P_{si}), a consumer-dependent electricity tax (t_{jt}) and a transmission and distribution margin (m_{sijt}) that varies among consumers. Some sectors are also charged a multiplicative value added tax, $\omega_{jt.}$

(10) $$PC_{sijt} = \{P_{si} + t_{jt} + m_{sijt}\}(1 + \omega_{jt})$$

When there is no constraint in the transmission network between regions, the wholesale price is common. When there is a network constraint, the wholesale price in each region must clear the market in that region, i.e., different area prices occur, and P_{sijt} and the purchaser prices follow:

(11) $$PC_{sijt} = \{P_{sijt} + t_{jt} + m_{sijt}\}(1 + \omega_{jt})$$

Supply

The producers are grouped according to generation technology (hydropower, thermal coal, nuclear, CHP etc.) and location (region). Each generation technology is represented by cost parameters and a number of physical and technical constraints, which restrict the system operation possibilities in each period (season and load). If a constraint is binding, a shadow price associated with the constraint becomes positive. The vector of production by technology, season and load in each region $\overline{X_{ist}}$ is:

(12) $$\overline{X_{ist}} = f(P_{ist}, \overline{X^*_{ist}}, \overline{PF_{ist}}, \overline{D_{ist}}, \overline{CAPT_{is\otimes t}},)$$

a function of the electricity purchaser price, a vector of production capacities by technology, $\overline{X_{ist}}^{*}$, in the region at the time, a vector of primary energy fuel prices by region, $\overline{PF_{ist}}$, at the time, a vector of other operating cost by technology and region, $\overline{D}_{ist}$, at the time, and a matrix of transmission capacities between regions, $\overline{CAPT_{is\otimes t}}$.

Whether investments in production or transmission capacities are made, they depend on the realized equilibrium electricity prices, differences in the area prices, and the costs related to the capacity expansion. There is an upper limit for investments, $\overline{K_{ist}}$, when the basic resource is limited by scarcity or environmental or political reasons.

(13) $$\overline{X^{*}_{ist}} = g(\overline{P_{ist}}, \overline{PF_{ist}}, \overline{D_{ist}}, \overline{E}_{ist}, \overline{K_{ist}})$$

The details of the supply model are elaborated in Appendix A (see also Johnsen, 1998).
The electricity trade between countries, $X_{s,i,l,m}X_{s,i,m,l}$, is limited by transmission capacities, ($CAPT_{l,m}$), between each pair of countries, *l* and *m*:

(14) $$X_{s,i,l,m}X_{s,i,m,l} \leq CAPT_{l,m}$$

where $X_{s,i,l,m}$ is the trade in seasons and load block *i* between countries *l* and *m*. Within one load block, the trade is restricted to only one direction. We assume one unit transmission price ($\tau_{l,m}$) between countries *l* and *m*. Aggregated transmission costs are a product of the unit transmission cost, the power trade and the length of the load period (ϑ_{si}).

(15) $$C_T = \sum_{s}\sum_{i}\sum_{l}\sum_{m}\vartheta_{s,i}\tau_{l,m}X_{s,i,l,m}$$

All the Nordic countries have network connections to non-Nordic countries. The export and import through these connections are determined exogenously. The load and season prices in the “third country” follow the observed distribution, while the price level follows the primary energy cost in thermal plants.

Market equilibrium

There is one unique equilibrium condition for each load block. In each load block, the power generation (supply) plus import must be greater or equal to the sum of domestic demand and export:

(16)
$$\sum_k Y_{s,BL,Kl} U_{skl} + \sum_m X_{s,BB,ml} \geq \sum_j Z_{sBB,jl} + \sum_m X_{s,BB,lm} + e_{s,BB,l}$$

(17)
$$\sum_{h=BL..ML} \sum_k Y_{s,h,k,l} + \sum_m X_{s,MB,ml} \geq \sum_j Z_{s,MB,jl} + \sum_m X_{s,MB,lm} + e_{s,MB,l}$$

(18)
$$\sum_{h=BL..ML..HL} \sum_k X_{s,h,k,l} + \sum_m X_{s,HB,m,l} \geq \sum_j Z_{s,HB,j,l} + \sum_{m,l} X_{s,HB,l,m} + e_{s,HB,l}$$

(19)
$$\sum_h \sum_k Y_{s,h,k,l} + \sum_m X_{s,PB,m,l} \geq \sum_j Z_{s,PB,j,l} + \sum_m X_{s,PB,l,m} + e_{s,PB,l}$$

Electricity imported to a region is a perfect substitute for regional generation.

Solution of the model

The solution of the model is found by maximization of the sum of the consumer (CS) and producer surpluses (PS) for all regions, i.e., the whole Nordic electricity market, less the transmission costs between each pair of regions. This corresponds with the assumption of perfect competition. All electricity producers and purchasers face the same electricity price, unless area prices are influenced by transmission constraints. The prices equal the marginal cost of electricity, and the price differences across regions result from transmission costs and eventually shadow prices of transmission capacities:

(20)

$$\left(CS + PS\right)_{\max} = \sum_s \sum_i \sum_j \sum_l \int_0^{Zsijl} \vartheta_{s,i} P_{s,i,j,l}(u)du - C_p - C_T - \sum_k \sum_l l_{k,l} \phi_{k,l} - \sum_l \sum_m T_{l,m} \psi_{l,m}$$

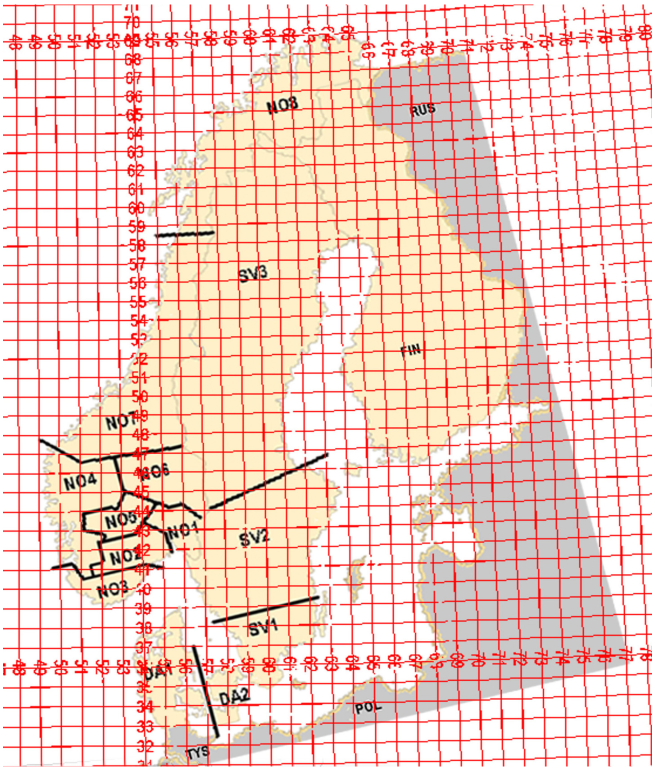
where $P_{sijl}(u)$ is the inverted demand equation (9), and where taxes and transportation margins are subtracted.

Data

NWE (Norwegian Water Resources and Energy Directorate) data cover weekly inflow to the Norwegian hydro storages in the period 1931–2004. The inflow series is based on estimations of the amount of water that would have been available in today's water reservoirs week by week in the period. In the estimations we have utilized data from 1980 to 1999, as this is the period of RegClim historic data[3].

RegClim provided data series concerning precipitation, accumulated snow storage, daily snowfall, runoff and evaporation for the periods 1980–1999 and 2030–2049. The data series originates from an experiment where RegClim compared the periods 1980–99 and 2030–49 with regard to certain climate indicators (Bjørge, Haugen et al., 2000). The data series reflects observations at 444 geographical points in the Nordic region. The map in figure 3 shows how the observations are described by the inflow model's grid system.

Figure 3: The data grid for climate variables



[3] Unfortunately, our inflow data cover just the Norwegian part of the hydrological system. However, the three Nordic countries—Norway, Sweden and Finland—have similar inflow patterns. We then estimate an inflow model for expected inflow based on historical data on total inflow in Norway, and we assume that the estimated coefficients can be used to simulate inflow in regional Norway, Sweden and Finland. (The climate variables are different). Denmark has almost no hydropower.

Every grid in the system represents an area of 55*55 km, which indicates that it is a coarse description of the terrain. Each grid intersection indicates one observation point and is described by latitude and longitude. The data set includes daily observations for all variables at each point. As inflow is described on a weekly basis, we aggregate the observations of each climate variable to weekly numbers[4].

In the electricity market model, the Nordic area is split into 14 regions (see map in figure 2). We aggregate climate variable *k,* rain (R), snow (S, S*), evaporation (E)) from square *i* to region *j*, Z_{ij}^{k}, by a set of weights, ξ_{ji}^{k}:

(21) $$Z_j^k = \sum_{i=1}^{n_k} \xi_{ji}^k Z_{ji}^k$$

where n_k is the number of observations in region *j*. Any observation measured along the coast is given less weight than an inland or mountain observation, as it gives less inflow to the reservoirs.

(22) $$\xi_{ji}^k = \begin{Bmatrix} 0{,}0 \rightarrow f = coast \\ 0{,}5 \rightarrow 0 = inland \\ 1{,}0 \rightarrow f = mountain \end{Bmatrix}$$

The climate scenario from RegClim is based on the global model ECHAM4/OPYC3 from the Max Planck Institute. The IPCC scenario IS92a that drives this model (RegClim.2, 2002) is based on the assumption that CO_2 emissions will increase annually by 1% from 1990 (IPCC 2000). This indicates a doubling in the CO_2 concentration by 2050. The IS92a scenario is not necessarily the most likely scenario, as there is no objective way to assign likelihood to any of the scenarios developed by IPCC (Nakicenovic, Alcamo et al., 2002). According to RegClim, the model gives a realistic picture of the current climate and is therefore chosen as the basis for dynamic downscaling (Bergström, Andrèasson et al., 2003) to a regional basis.

[4] By doing this aggregation, we assume that there will not be any structural changes over the time period. This may include, for example, changes in the cloud systems. The data material from RegClim includes 30 days each month, i.e., the last week of every year has only three days. To obtain an approximation to a normal week, this week of the year is multiplied by 7/3. Evaporation, precipitation, snowfall and runoff are then described as the total amount during each week. Accumulated snow, temperature and wind are described as an average weekly observation.

The global climate models typically have a coarse spatial resolution and are not capable of including regional differences as to give a realistic description of the region (Benestad, 2003). RegClim achieved the regional climate scenario by using a model for atmospheric dynamic downscaling, HIRHAM. The climate scenarios obtained from HIRHAM, are better suited to attending to geographical differences (mountains, fjords, forests, etc.) in the Nordic region (RegClim.2, 2002). There are differences between the computed data and the observed average variables. This is due partly to the coarse spatial resolution but also to inadequacies in the regional model. The results from this analysis are based on one of many scenarios, meaning that the model data for one historical day cannot be directly compared with the observed weather situation of that specific date.

RegClim has provided historical data (1980–99) for the estimation of the inflow model and has projected values for the period 2030–49 that are utilized to simulate inflow into the reservoirs in the future. As the RegClim values in one specific year are stochastic, e.g., the stochastic weather, we estimate the linear trend in inflow during 2001–2040. We estimate the average weekly inflow during 1980–1999, and the average inflow during 2030–2049. The linear trend is found by:

$$\text{Growth rate per year 1990–2040} = \left(\frac{\sum_{2030}^{2049} Inflow_{week} / 20yrs}{\sum_{1980}^{1999} Inflow_{week} / 20yrs} \right)^{1/50}$$

The increased inflow into the electricity market model is represented by the simulated inflow values in the period 2001–2040.

We apply the temperature data from RegClim to calculate the partial effect on energy demand.

Scenarios

We produce one base scenario for the development of the Nordic electricity market, where the simulated effects of climate change are excluded, and one scenario where the changes are included, and we compare these two scenarios. The assumptions on activity growth in our partial electricity market model are based on simulations on macroeconomic models (see Aune, Bye et al., 2005). In the base scenario, we assume the annual growth in income of the household and services sector to be 1.8%. In terms of energy-intensive industries, there is an annual reduction in production of 0.5%. As for the rest of the industry sector, the analysis is based on a 1% annual growth rate. The production technologies are specified by future cost (see Aune, Bye et al., 2005). The price pattern over loads and periods outside the Nordic area follow the historic price pattern (2001/2002), while the price level follows the long-term marginal cost of expansion. Approaching 2010, the price increases gradually to equal the total cost of investing in new gas power in Germany in 2010. In addition, Finland is importing electricity from Russia. The Russian price is low enough for Finland to import the maximum amount in the entire period (transmission constrained). Some of the power-producing technologies will emit greenhouse gases and will face permit prices on their emissions. The CO_2 permit price is set to 125 NOK/ton emitted in both scenarios, as we assume that the Nordic emissions are too modest to influence the international quota price (Aune, Bye et al., 2005).

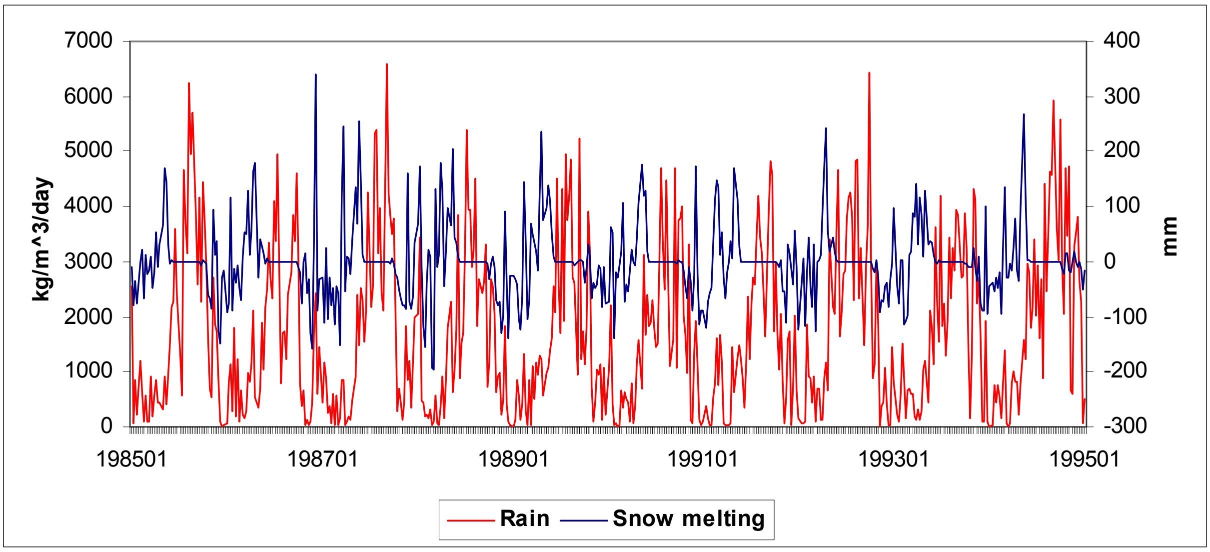
Results

This analysis comprises three parts: the estimation and simulation of the climate model (inflow and wind), the simulation of the partial temperature effect, and the simulation of the total electricity market model. Since all three elements are based on separate model exercises, we report on each of them separately below.

Inflow model

Some variables in the inflow model turned out to be not significant at a 5% significance level, for instance, evaporation probably due to high correlation with rain. Engeland, Engen-Skaugen et al. (2004) state that there are great challenges in developing models to intercept the effect of evaporation. The effect of rain in weeks 17, 18, 19 and 20 and the effect of snow melting dummies in weeks 20, 21 and 22 are not significant and are therefore excluded from the model. Our data series shows that rain and snow melting are negatively correlated, i.e., that snow melting is correlated to the negative change in the stock of snow. When there is heavy rain, there is more snow melting. The correlation between rain and snow melting is more than 0.45 in 50% of the time, and more than 0.7 in half of this observation period. Figure 4 shows the relationship between rain and snow melting in Norway in the period 1985–1995. There seems to be a lag on snow melting through runoff from soaked soil, and the model estimates showed that snow melting is significant with a one-week lag.

Figure 4: Rain and snow melting in Norway 1985–1995



Equation (23) illustrates the final inflow model.

(23) $$I_t = \beta_0 R_t + \beta_1 R_t D21_t + \beta_2 R_t D22_t + \beta_3 R_t D23_t + \gamma_1 S_t D17_{t-1} + \gamma_2 S_t D18_{t-1} + \gamma_3 S_t D19_{t-1} + \gamma_4 S_t D23_{t-1} + \varepsilon_t$$

The partial R^2s in table 1 show that rain (β_0) has the greatest influence on inflow (0.535). The snow dummies are negative, as a negative change in accumulated snow indicates melting. Increased amounts of melting will increase inflow.

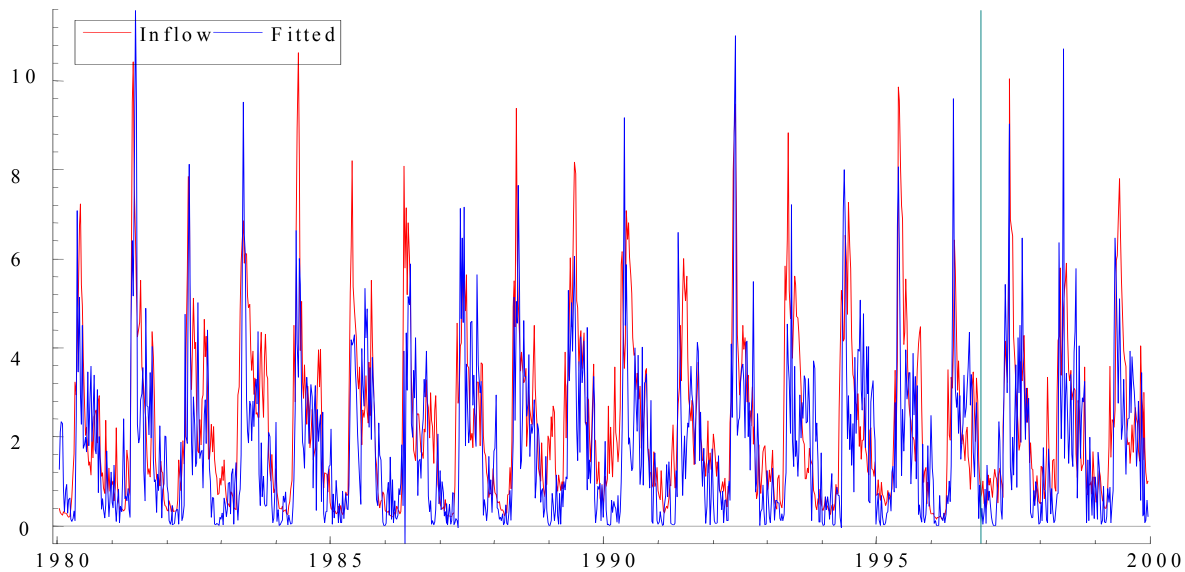
The melting is greatest in the first weeks and fades out in the last week, i.e., even if the estimated coefficient is higher in the last week, less inflow shows up in the reservoirs. The large coefficient in week 23 may be due to the correlation between rain and snow, as this is the only week in which both parameters occur.

Table 1: Estimation results from the regression model

	Coefficient	Std. Error	t-value	t-prob	Partial R^2
Rain					
β_0	0.89	0.02	31.7	0.000	0.535
β_1	2.01	0.25	7.95	0.000	0.067
β_2	1.93	0.204	9.44	0.000	0.093
β_3	1.43	0.167	8.61	0.000	0.078
Snow					
γ_1	–11.17	3.86	–2.89	0.004	0.009
γ_2	–18.65	4.09	–4.56	0.000	0.023
γ_3	–25.45	3.62	–7.02	0.000	0.053
γ_4	–437.91	79.47	–5.51	0.000	0.033

Figure 5 shows the model-estimated inflow in 1980–2000 and the actual inflow reported from NWE in the same period. As the data series on rain and snow from RegClim is rather stochastic, the estimated model will simulate a stochastic inflow. The figure illustrates that the estimated inflow and the actual inflow in this period follows the same pattern.

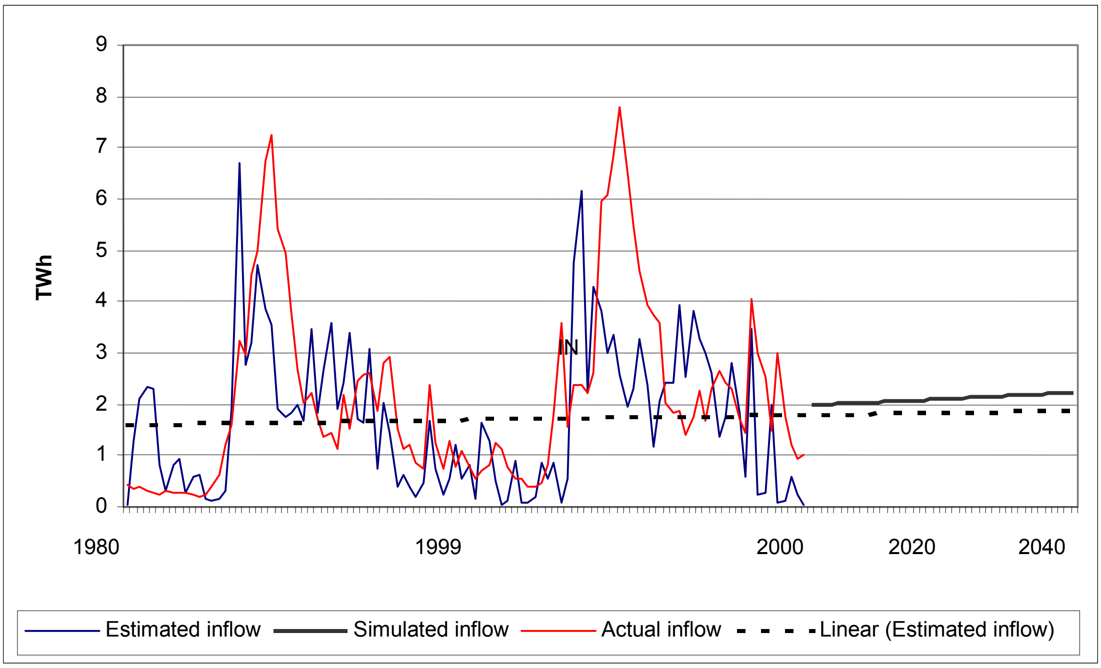
Figure 5: Observed and model-fitted inflow (TWh) 1980–2000



In figure 6 we show the simulated inflow for Norway in the period 1980–2040. The figure illustrates in some detail how well the model simulates inflow relative to the actual inflow each week in two random years, 1980 and 1999, the estimated trend over these years extended to 2040 (the stapled line), and the model-simulated trend for the period 2001–2040 (the solid line). Although the historic fit seems to be close over the whole year, there are some important discrepancies with respect to the periods within a year. The estimated peak inflow seems to shift somewhat leftward compared with the actual inflow during the melting period. For the electricity market simulations, this is a minor problem, since aggregation over model periods apparently eliminates the problem. Whether this constitutes a fundamental climate model problem is a more complex issue.

The extended 1980–2000 trend to 2000–2040 is substantially lower than the model-simulated inflow trend. This shows that the climate variables are not linear in the RegClim forecasting data, and may represent a downward bias in the linear estimated climate model (cf. the estimated trend over stochastic variables in section 3). Figure 6 shows that climate changes will increase inflow in Norway by approximately 10% in the following 40 years.

Figure 6: Inflow in Norway 1980–2040



Based on the RegClim forecast for the climate change variables, we now simulate the potential seasonal changes in inflow development, to be implemented in the electricity market model. Season 1 includes weeks 1–17, season 2 includes weeks 18–35, and season 3 includes weeks 36–52. For Norway, the inflow model predicts that inflow in existing hydro reservoirs will increase in all seasons from 2001 to 2040. The aggregation from percentage increase in weeks to season is based on historical data of weekly inflow as weights. Season 1 will normally have 11%, season 2 will have 71%, and season 3 will have 18% of the annual inflow. The total effect of climate changes is now calculated to be an increase in inflow of 10.3%. Sælthun, Aittioniemi et al., (1998) concluded that total runoff values after 100 years could increase by some 20% in the western regions but decrease in the southern regions. The impact of hydropower production in the total Nordic area was estimated to +2.5%. Our results for the next 40 years seem to be at the upper limit. However, they are based on revised climate projections, which will also increase the Sælthun et al. results. The increased inflow is explained directly by rain and snow melting, and indirectly by increased temperature and runoff. Most of the eight Norwegian regions will have an increase of more than 5% in inflow in the following 40 years; region 5 is the only exception with an expected increase by only 4.5%. In general, the western and northern regions in Norway will face the largest increases in inflow. Region 8, the upper northern part, is expected to face an increase of 19.5% from 2001 to 2040.

The inflow model is estimated for Norway, but we assume the same fundamentals when simulating inflow in the other Nordic countries, although all the climate change factors are calculated separately in RegClim. The total increase in inflow in Sweden is 6.1% from 2001 to 2040. The northern region shows the largest increase in inflow, but only slightly over the average.

In Finland, total inflow increased by 14.6% from 2001 to 2004. This is the largest percentage increase in the Nordic region, but Finland is a minor contributor to the total hydro capacity in the Nordic countries. The change only amounts to 1.8 TWh in 2040.

Wind speed

According to RegClim's data series, the increase in wind speed in Norway is 1.2% to 2040. Some regions will experience a stronger growth in wind speed than others. The coastal regions, 3, 4, 7 and 8 (see figure 1) will face the greatest increase. This means that the same regions face increasing wind speed and increased inflow. Renewable energy production adds up in a few regions with limited demand and puts a greater stress on the transmission networks.

Sweden is expected to experience more wind in all seasons until 2040. The increase to 2040 will be 1%. The wind speed is highest in region 1. The average wind speed in Finland is the lowest in the Nordic region. Climate change indicates fewer strong winds in season 2, but the rest of the year will experience stronger winds, and the annual increase in wind speed is 0.5% from 2001 to 2040. Denmark has significantly stronger wind than the other Nordic countries. The annual increase in 2040 is 0.8%, and the wind speed will increase most in the season 2 and least in season 1. Although the amount of wind power production is relatively small, this implies that the production in season 2 increases and thus implies another demand for water storage handling.

Temperature model

The estimated temperature model is reported in table 2 (see Johnsen and Spjeldnæs, 2005).

Table 2: Estimation results

Demand equation	Coefficients	Standard deviations
Constant	3.52	(0.33)
ln (E_{t-1})	–0.66	(0.06)
Δ HDD_t	0.03	(0.002)
Δ HDD_{t-1}	0.02	(0.002)
Δ ln (W_t)	0.02	(0.006)
ln (W_{t-1})	0.02	(0.008)
Δ ln (D_t)	–0.14	(0.04)
ln (D_{t-1})	–0.06	(0.01)
Δ ln (p_t)	–0.19	(0.09)
ln (p_{t-1})	–0.03	(0.008)
$D275_t$*ln(p_{t-1})	–0.009	(0.001)
ln(pf_{t-1})	0.06	(0.01)
ln(Y_{t-1})	0.21	(0.06)
+ Holiday dummies		
S (standard deviation)	0.0296	
R^2	0.86	

We simulate the effect on demand for electricity of changing temperature by holding constant all variables other than temperature. According to RegClim, the average temperature over the year in both Norway and Sweden increases by 0.9 °C from 2001 to 2040. The temperature model simulates a 3% reduction in demand due to increased temperature. The major temperature increase will be in the northern part of the country. Finland will have a total reduction in demand of 4% from 2001 to 2040. The annual temperature in Finland is expected to increase by 1.2 °C in the next 40 years. Denmark is expected to face a reduction in annual demand of 2.5%, as there will only be an increase in temperature of approximately 0.75 °C in the following 40 years.

The total electricity market

We produced one base scenario excluding the simulated changes in inflow, temperature-dependent demand and wind, and one scenario where the climate changes were included. Table 3 shows the results from these scenarios in 2040 with regard to supply, demand, trade and electricity prices. The simulations indicate that the Nordic region is expected to have an increase in supply of electricity of 1.8% (8.1 TWh) in 2040 because of climate change.

This increase seems small compared with the total increase in primary energy (water and wind). However, hydropower only amounts to approximately 50% of total production in the Nordic region. Besides, an increase in hydropower production at low cost substitutes marginal thermal production (gas-fired power) in Sweden and Finland. In addition, as the supply of "cheap" electricity increases in the climate scenario, the electricity price drops. This reduces new investments in power production capacity in general over the time period (cf. the increasing marginal cost of investment).

Total demand for electricity is predicted to increase by 1.4% (6.3 TWh), despite the reduced effect of increased temperature on demand. The increased supply of electricity reduces the average electricity price by 2.4 N.øre/kWh or approximately 10% of the wholesale price. The price effect then offsets the temperature effect. In addition, some demand is temperature independent.

There will be an increase in net exports from the Nordic area to the rest of Europe of 22% (1.8 TWh) in 2040. The prices in the Nordic area are less than the "third country" price, but even stronger exports are limited by effective bounds on transmission.

In Norway, climate changes will increase the supply of electricity relatively more than demand. This implies more net exports to neighboring countries and the rest of Europe. In both Sweden and Finland, supply of electricity is reduced until 2030 relative to the base scenario, as investments in gas power plants are postponed because of unprofitability when cheaper hydropower may be imported from Norway. After 2030, exports from Sweden to its Nordic neighbors and the rest of Europe increase again because of increased production of hydropower and gas power compared with the base scenario. Denmark reduces its coal production and imports more from the south of Norway and Sweden, but at the same time increases exports to Europe. As Sweden, Finland and Denmark will postpone new investments and will periodically reduce production, the capacity of the reservoirs and electricity production in Norway will be challenged.

Table 3: The effect of climate changes in 2040: A comparison of the base and climate scenario from Normod-T

	Supply		Demand		Trade		Price [1)]
	%	**TWh**	**%**	**TWh**	**%**	**TWh**	**øre/KWh**
Norway	8.4	12.5	3.2	4.6	136.0	7.9	–5.3[2)]
Sweden	–0.03	–0.5	0.5	0.9	–29.8	–1.4	–1.6
Finland	–5.0	–4.0	0.8	0.7	–131	4.7	-1.5
Denmark	0.3	0.1	0.5	0.2	–11.0	–0.1	–1.0
The northern region	**1.8**	**8.1**	**1.4**	**6.3**	**21.9**	**1.8**	**–1.0**

1) Price (N.øre/KWh) weighted with consumption

2) Region 7 and 8 contribute strongly to the reduction, as this is where the largest increase in inflow is expected to occur and transmission out of these regions is restricted. If these regions are excluded, approximately 2 N.øre/KWh reduces the Norwegian price

There are two important effects of climate changes on the transmission network. First, effective bounds on transmission occur more often because of more exchange of electricity, and second, as the pressure on the transmission grid is larger, the shadow price of the capacity constraint increases. This implies higher prices for the surplus areas and lower prices for the excess areas. There are effective bounds on transmission capacities both within each country and between the countries. In Norway, transmission from the western regions to the eastern regions is restricted in the winter seasons because of a significantly greater supply of electricity in the western regions. The northern regions in Sweden are hydropower abundant, and the cables from north to south are increasingly overloaded in the winter seasons when inflow increases. In the climate scenario, the cables from Norway to Denmark, Sweden and Finland will be overloaded in all seasons from 2010. This is a few years earlier than in the base scenario. There will be an effective limit on transmission from Sweden (SW2) to Denmark (DEN1) in all seasons. The time perspective is not influenced by the climate changes, but the shadow price is higher because of greater pressure on the effective limit. The transmission line between Finland and Sweden (SW2) will also face an effective limit in winter from 2030 to 2040. This is a few years earlier than in the base scenario. Several other cables will be overloaded for short time periods. The cables between each country and the rest of Europe will also be full for longer because of climate changes. If a transmission-restricted region is hydropower abundant, the pressure on the upper limit of the reservoir will increase, and the limit may be effective and may result in a positive shadow price. Effective limits and increasing shadow prices may indicate profitable investments in capacity, but the analysis of the potential profitability is left for further studies.

Summary and conclusions

We applied detailed information from natural science research on climate change to estimate a climate model that captures changes in inflow and wind speed when climate changes. Changing outdoor temperature also influences energy demand. We incorporated all the partial effects on supply and demand into an electricity market model for the Nordic countries and simulated the outcome on total supply of energy, prices, and demand and transmission constraints between regions.

The increase in primary energy from 2001 to 2004 is approximately 10%. However, the unit cost of hydropower and wind power production is reduced as a consequence of increased returns to scale in plant, so prices of energy decrease. This reduces the profitability of investing in thermal power plants. In addition, hydropower and wind power constitute only 50% of the total Nordic Supply. The total climate effect on production in 2040 is then less than 2%.

Increased temperature initially reduces the temperature-based energy demand by approximately 3%. However, reduced prices of energy increase demand, and this overrides the temperature effect. The total change in demand is an increase of 1.5%.

Since large consumers are located far from the hydropower and wind power plants, increased demand and a more skewed distribution of the supply imply more frequent and more important transmission constraints. In the next stage, this may trigger new investments in network capacity.

References

Aune, F. R., T. Bye and P.V. Hansen (2005). “A common Norwegian–Swedish certificate market for electricity.” Reports 2005/18, Statistics Norway

Beldring, S., K. Engeland, L.A. Roald, N.R. Sælthun and A.Voksø (2003). “Estimation of parameters in a distributed precipitation-runoff model for Norway.” *Hydrology and Earth System Sciences* **7**: 304–316.

Beldring, S., L. A. Roald, T. Engen-Skaugen, E.J. Førland, O.E. Tveito, K. Engeland and R. Benestad (2005). “Climate change impact on water balance in Norway.” Report No. 1, Norwegian Water Resources and Energy Directorate, January, Oslo (available from http://www.nve.no/modules/module_109/publisher_view_product.asp?iEntityId=2930).

Benestad, R. E. (2003). “Tentative probabilistic temperature scenarios for Northern Europe.” *Tellus* 56A(7): 89–101.

Bergström, S. (1976). “Development and application of a conceptual runoff model for Scandinavian catchments.” RHO- Report no 7, SMHI, Norrköping

Bergström, S., J. Andrèasson, S. Beldring, B. Carlsson, L.P. Graham, J.F. Jònsdottir, K. Engeland, M.A. Turunen, B. Velhiläinen and E.J. Førland (2003). “Climate Change Impacts on the Hydro Power in the Nordic Countries. State of the art and discussion of principles.” Report no. 1, RegClim, May, Oslo (available from http://www.regclim.no)

Bergström, S., J. Harlin, et al. (1992). “Spillway design floods in Sweden I: New guidelines.” *Hydrological Sciences Journal*37(5): 505–519.

Bjørge, D., D. Haugen and T.E. Nordeng (2000). “Dynamical downscaling experiments within the RegClim project”. Research report no.103, The Norwegian Meteorological Institute, August, Oslo.

Bye, T. and P. V. Hansen (2005). “A Simultaneous Multimarket model for the Demand Elasticity—An econometric study of Sweden and Norway.” Forthcoming Discussion Paper, Norway Statistics, September, Oslo

Engeland, K., T. Engen-Skaugen, J.E. Haugen, S. Beldring and E. Førland (2004). “Comparison of evaporation estimated by the HIRHAM and GWB models for present climate and climate change scenarios.” Report 17, The Norwegian Meteorological Institute, November, Oslo (available at http://met.no/english/r_and_d_activities/publications/2004/17_2004/017_2004.pdf)

Førland, E., L. A. Roald, O.E Tveito and E. Hanssen-Bauer (2000). “Past and future variations in climate and runoff in Norway.” Report no. 19, NWE, November, Oslo (available at http://www.nve.no/FileArchive/81/pilot_nykh.pdf)
Gabrielsen, K. (2005). "Climate change and the future Nordic electricity market—supply, demand, trade and transmission". Reports 2005/17, Statistics Norway

Gellens, D. and E. Roulin (1998). “Streamflow response of Belgian catchments to IPCC climate change scenarios.” *Journal of Hydrology* 210: 242–258.

IPCC (2000). *Summary report on emission scenarios. A special report of working group III of the IPCC* at http://www.ipcc.ch/pub/spm_sres.pdf

Johnsen, T. A. (1998). "Modeling the Norwegian and Nordic Electricity Markets". PhD thesis, University of Oslo

Johnsen, T. A. and T. A. Haug (2004). "Data for a Nordic Regional Electricity Market Model, Production Sites, Transmission Networks, Electricity Demand and Prices." Note 37, Statistics Norway.

Johnsen, T. A. and N. Spjeldnæs (2005). "Electricity demand and temperature—an empirical methodology for temperature adjustment in Norway." Draft, NWE, January, Oslo

Kaczmarek, Z., K. M. Somlyòdy, V. Priazhinskaya (1996). "Water Resources Management in the Face of Climatic/Hydrologic Uncertainties." Water Science and Technology Library, Kluwer Academic Publisher, Dordrecht.

Kuusisto, E. (2004). "Climate, water and energy. A summary of a joint Nordic project 2002–2003." Report no.4, Finnish Environmental Institute, August (available at http://www.os.is/cwefiles/downloads/pm/CWE-Esko_low.pdf)

Lemmelä, R and N. Helenius (1998). "Proceedings of the Second International Conference on Climate and Water, Espoo, Finland, 17–20 August", p.576-587 (available from http://www.rlemmela@ahti.hut.fi

Lettenmaier, D. P., A. W. Wood, R. N. Palmer, E.F. Wood and E.Z. Stakhiv (1999). "Water resources implications of global warming*." Climatic Change* 43: 537–579.

Middelkoop, H., K. Daamen, D. Gellens, W. Grabs, J.C.L. Kwadijk, H. Lang, B.W.A.H Palmet, B. Shädler, J. Schulla and K. Wilke (2001). "Impact of climate change on hydrological regimes and water resources management in Rhine basin." *Climatic Change* 49: 105–128.

Müller-Wohlfeil, D. I., G. Bürger and W. Lahmer (2000). "Response of a river catchment to climatic change. Application of expanded downscaling to Northern Germany." *Climatic Change* 47: 399–420.

Nakicenovic, N., J. Alcamo, G. Davis, B. de Vries, J. Fenhann, S. Gaffin, K. Gregory, A. Grübler, T.Y. Jung, T. Kram, E.L. La Rovere, L. Michaelis, S.Mori, T. Morita, W. Pepper, H. Picher, L. Price, K. Riahi, A. Roehrl, H. Rogner, A. Sankovski, M. Schlesinger, P. Shukla, S. Smith, R. Swart, S. van Rooijen, N. Victor and Z. Dadi (2002). "Special report on emission scenarios IPCC. " Chapter 1.4 at http://www.grida.no/climate/ipcc/emission/027.htm

RegClim.2. (2003) "Regional Climate Development under Global Warming." Final Report, Phase I, II, , 1997–2002." (Available at http://www.regclim.met.no)

Reynard, N. S., C. Prudhomme and S.M. Crooks. (2001). "The flood characteristics of large U.K. Rivers. Potential effects of climate change and land use." *Climatic Change* 48: 343–359.

Rogers, J. S. and J. G. Rowse (1989). "Canadian interregional electricity trade. Analyzing the gains from system integration during 1990–2020." *Energy Economics* April 1989: 105–118.

Sælthun, N. R., P. Aittioniemi, S. Bergström, K. Einarsson, T. Johannneson, G. Lundström, P-E. Oslen, T. Thomsen, B. Vedhviläinen and K.O Aamot (1998). "Climate change impacts on runoff and hydropower in the Nordic Countries. Final report from the project *Climate Change and Energy Production*." *TemaNord* 1998:552

A. The supply model

In this appendix, we explore some of the details on the supply side of the electricity market model (see Johnsen, 1998).

A.1. Supply from thermal plants

In a thermal power plant, the operating costs ($OC_{h,k,l}$) for load mode h, technology k and country l is:

(A.1.1) $$OC_{h,k,l} = \frac{q_{k,l}}{\mu_{k,l}} + \alpha^1{}_k + \alpha^2{}_{h,k}$$

The first term is a fuel cost, which depends on the fuel price ($q_{k,l}$) and the conversion efficiency ($0<\mu_{k,l}< 1$). The second term is a variable non-fuel cost ($\alpha 1_k$), which includes different materials, and labor costs. The third term is an additional non-fuel cost ($\alpha 2_{h,k}$), which reflects costs associated with the start of a plant in any load mode other than base load.

Heat may be seen as a by-product of electricity generation.

The operation cost ($OC_{s,h,k,l}$) for combined heat and power technologies is season, mode, technology and country specific.

(A.1.2) $$OC_{s,h,k,l} = \frac{q_{k,l} - ph_{s,h,l}(\mu_{k,l} - \mu_{k,l})}{\mu_{k,l}} + \alpha^1{}_k + \alpha^2{}_{h,k}$$

The mode-specific prices of heated water are weighted averages of the market price of heated water in the different load blocks. The total conversion efficiency, $\mu_{k,l}$, is the total output of energy.

In the short term, thermal plants may face both capacity and fuel constraints. For technology k and country l, the annual energy output is the sum over seasons (s) and modes (h) of the product of the load generation ($Y_{s,h,k,l}$) and the number of hours ($\phi_{s,h}$). One year includes 8,760 hours, and $\phi_{s,h}$ and $\pi_{k,l}$ are measured in 100 hour increments. The annual number of hours less the number required for maintenance and repair ($\pi_{k,l}$) multiplied by the capacity (CAP) limits the annual energy output from each technology.

(A.1.3) $$\sum_{s}\sum_{h}\phi_{s,h}Y_{s,h,k,l} \leq (87,6-\pi_{k,l})CAP_{k,l}$$

When a plant is stopped for maintenance and repair, it is not disposable in any load modes. The constraint is:

(A.1.4) $$\sum_{s}\rho_{s}MR_{s,k,l} \geq \pi_{k,l}CAP_{k,l}$$

where ρ_s is the number of hours in season s, and $MR_{s,k,l}$ is the amount of capacity out of service for periodic maintenance and repair in season s. The sum of actual generation and capacity out of service each season will be restricted by the available generation capacity.

(A.1.5) $$\sum_{h}Y_{s,h,k,l} + MR_{s,k,l} \leq CAP_{k,l}$$

We introduce an exogenous, national security margin (σ_l) that determines how large the national generation capacity in a season is to be compared with domestic peak generation.

(A.1.6) $$(1+\sigma_l)\sum_{h}\sum_{k}\left(Y_{s,h,k,l} + MR_{s,k,l}\right) \leq \sum_{k}CAP_{k,l}$$

It might be profitable to operate with reduced capacity through low-price periods, rather than to stop the plant. The capacity utilization is restricted by:

(A.1.7) $$cu_k \leq U_{s,k,l} \leq 1$$

where cu_k is the lower limit for capacity utilization.

Limitations in the availability of fuel r in country l are written as:

(A.1.8) $$\sum_s \sum_k \left\{ \frac{\left[Y_{s,BL,k} \left(U_{s,k,l} \varphi_{s,BB} + \phi_{s,ML} \right) + \sum_{h=ML,HL,PL} Y_{s,h,k,l} \phi_{s,h} \right]}{\mu_{k,l}} \right\} \chi_{k,s,l} \leq b_{s,l}$$

The left side indicates the annual demand for fuel, r. The coefficient $\chi_{k,s,l}$ connects technology k with its fuel, and b is the annual fuel quantity available. BL, ML, HL and PL represent base load, medium load, high load and peak load. BB is the base block

A.2 Hydropower capacity constraints

The short-term marginal fuel cost of production in a hydropower plant is zero as the water is free, but the rest of the short-term marginal cost in equation A.1.1 prevails. Optimizing the value of running the hydropower plants bring about a water value that reflects the opportunity cost of producing power by the other technologies at any time. For the hydropower plants, the constraints in A.1.3, A.1.5 and A.1.6 prevail.

In each season, s, the base load (BL) hydropower (HP) generation in country l ($Y_{s, BL..HP, l}$) should be equal to or greater than a lower limit (η_l), i.e.:

(A.2.1) $$Y_{s, BL..HP,l} \geq \eta_l$$

Even though hydropower production can be regulated at low cost, there may be some physical constraints on the variation over the day, or between the base and peak generation:

(A.2.2) $$\sum_h Y_{sh,HP,l} \leq (1+\gamma_l) Y_{s,BL,HP,l}$$

where γ_l is the upper limit on the increase in hydropower generation from base load to peak load mode within a day. There is an upper limit on the reservoir capacity, δ_l, in the two winter seasons. The constraint on the reservoir capacity is:

(A.2.3) $$\sum_h \left(Y_{w1,h,HP,l} \phi_{w1,h} + Y_{w2,h,HP,l} \phi_{w2,h} \right) \leq \delta_l$$

where ϕ_{sh} is the number of hours in load mode h in season s. The total amount of hydropower production must be less than or equal to the total inflow, Δ, to the system in the long run, although it may vary year by year.

(A.2.4) $$\sum\left(Y_{w1,h,HP,1}\phi_{w1,h} + Y_{S,h,HP,1}\phi_{w1,h} + Y_{w2,h,HP,1}\phi_{w1,h}\right) \leq \Delta$$

Recent publications in the series Discussion Papers

339 R. Aaberge and A. Langørgen (2003): Measuring the Benefits from Public Services: The Effects of Local Government Spending on the Distribution of Income in Norway

340 H. C. Bjørnland and H. Hungnes (2003): The importance of interest rates for forecasting the exchange rate

341 A. Bruvoll, T.Fæhn and Birger Strøm (2003): Quantifying Central Hypotheses on Environmental Kuznets Curves for a Rich Economy: A Computable General Equilibrium Study

342 E. Biørn, T. Skjerpen and K.R. Wangen (2003): Parametric Aggregation of Random Coefficient Cobb-Douglas Production Functions: Evidence from Manufacturing Industries

343 B. Bye, B. Strøm and T. Åvitsland (2003): Welfare effects of VAT reforms: A general equilibrium analysis

344 J.K. Dagsvik and S. Strøm (2003): Analyzing Labor Supply Behavior with Latent Job Opportunity Sets and Institutional Choice Constraints

345 A. Raknerud, T. Skjerpen and A. Rygh Swensen (2003): A linear demand system within a Seemingly Unrelated Time Series Equation framework

346 B.M. Larsen and R.Nesbakken (2003): How to quantify household electricity end-use consumption

347 B. Halvorsen, B. M. Larsen and R. Nesbakken (2003): Possibility for hedging from price increases in residential energy demand

348 S. Johansen and A. R. Swensen (2003): More on Testing Exact Rational Expectations in Cointegrated Vector Autoregressive Models: Restricted Drift Terms

349 B. Holtsmark (2003): The Kyoto Protocol without USA and Australia - with the Russian Federation as a strategic permit seller

350 J. Larsson (2003): Testing the Multiproduct Hypothesis on Norwegian Aluminium Industry Plants

351 T. Bye (2003): On the Price and Volume Effects from Green Certificates in the Energy Market

352 E. Holmøy (2003): Aggregate Industry Behaviour in a Monopolistic Competition Model with Heterogeneous Firms

353 A. O. Ervik, E.Holmøy and T. Hægeland (2003): A Theory-Based Measure of the Output of the Education Sector

354 E. Halvorsen (2003): A Cohort Analysis of Household Saving in Norway

355 I. Aslaksen and T. Synnestvedt (2003): Corporate environmental protection under uncertainty

356 S. Glomsrød and W. Taoyuan (2003): Coal cleaning: A viable strategy for reduced carbon emissions and improved environment in China?

357 A. Bruvoll T. Bye, J. Larsson og K. Telle (2003): Technological changes in the pulp and paper industry and the role of uniform versus selective environmental policy.

358 J.K. Dagsvik, S. Strøm and Z. Jia (2003): A Stochastic Model for the Utility of Income.

359 M. Rege and K. Telle (2003): Indirect Social Sanctions from Monetarily Unaffected Strangers in a Public Good Game.

360 R. Aaberge (2003): Mean-Spread-Preserving Transformation.

361 E. Halvorsen (2003): Financial Deregulation and Household Saving. The Norwegian Experience Revisited

362 E. Røed Larsen (2003): Are Rich Countries Immune to the Resource Curse? Evidence from Norway's Management of Its Oil Riches

363 E. Røed Larsen and Dag Einar Sommervoll (2003): Rising Inequality of Housing? Evidence from Segmented Housing Price Indices

364 R. Bjørnstad and T. Skjerpen (2003): Technology, Trade and Inequality

365 A. Raknerud, D. Rønningen and T. Skjerpen (2003): A method for improved capital measurement by combining accounts and firm investment data

366 B.J. Holtsmark and K.H. Alfsen (2004): PPP-correction of the IPCC emission scenarios - does it matter?

367 R. Aaberge, U. Colombino, E. Holmøy, B. Strøm and T. Wennemo (2004): Population ageing and fiscal sustainability: An integrated micro-macro analysis of required tax changes

368 E. Røed Larsen (2004): Does the CPI Mirror Costs.of.Living? Engel's Law Suggests Not in Norway

369 T. Skjerpen (2004): The dynamic factor model revisited: the identification problem remains

370 J.K. Dagsvik and A.L. Mathiassen (2004): Agricultural Production with Uncertain Water Supply

371 M. Greaker (2004): Industrial Competitiveness and Diffusion of New Pollution Abatement Technology – a new look at the Porter-hypothesis

372 G. Børnes Ringlund, K.E. Rosendahl and T. Skjerpen (2004): Does oilrig activity react to oil price changes? An empirical investigation

373 G. Liu (2004) Estimating Energy Demand Elasticities for OECD Countries. A Dynamic Panel Data Approach

374 K. Telle and J. Larsson (2004): Do environmental regulations hamper productivity growth? How accounting for improvements of firms' environmental performance can change the conclusion

375 K.R. Wangen (2004): Some Fundamental Problems in Becker, Grossman and Murphy's Implementation of Rational Addiction Theory

376 B.J. Holtsmark and K.H. Alfsen (2004): Implementation of the Kyoto Protocol without Russian participation

377 E. Røed Larsen (2004): Escaping the Resource Curse and the Dutch Disease? When and Why Norway Caught up with and Forged ahead of Its Neughbors

378 L. Andreassen (2004): Mortality, fertility and old age care in a two-sex growth model

379 E. Lund Sagen and F. R. Aune (2004): The Future European Natural Gas Market - are lower gas prices attainable?

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