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Gas power generation in Norway: Good or bad for the climate?

Revised version

Abstract:
Norway has abundant gas resources in the North Sea. The Norwegian gas production accounts for 2 percent of the world production and 17 percent of the European gas production. Despite huge gas production and resources, gas is not used for electricity generation in Norway. Excess capacity, cheap hydropower, low electricity prices and political restrictions have prevented gas based power generation in Norway. Lately, import of electric power from neighboring countries with fossil fuel based power systems has led industry spokesmen and various politicians to propose building of several gas power plants in Norway. Electric self-sufficiency, domestic natural gas utilization and environmental benefits through reduced coal power generation abroad are used as arguments to support construction of gas power plants in Norway.

Several industrial groups have applied for concession to build natural gas fired power stations. Initially, the Norwegian Pollution Control Authority (SFT) denied emissions concession referring to Norwegian obligations under the Kyoto protocol. In March 2000, however, a majority in parliament voted against the SFT-decision and advised the Government to issue concession. The core argument from both sides was the environmental impacts from gas power generation in Norway. SFT argued that increased power generation would lead to lower energy prices and thereby higher energy consumption and more pollution. The view of the majority of Parliament was that Norwegian gas power will replace coal power generation in Denmark and Germany and thus give lower total climate gas emissions since coal based power results in much higher emissions per unit of energy than gas power does.

The Nordic electricity system and market is very complex and therefore energy policy measures may result in numerous different impacts and repercussions. Therefore, we carry out a number of model simulations to analyze the impacts from introduction of Norwegian gas power generation into this market. We apply an equilibrium model for the Nordic electricity market. In order to describe important intra-year supply-side technology and fuel substitution, the Normod-T model has a detailed time-resolution. Our calculations show that none of the two views are completely right. The aggregate effect on climate emissions from producing gas power in Norway may be positive or negative, and depends heavily on the assumptions made.

Keywords: Electricity market, Gas power, Climate policy, Electricity trade

JEL classification: E1, F1, Q4, H3

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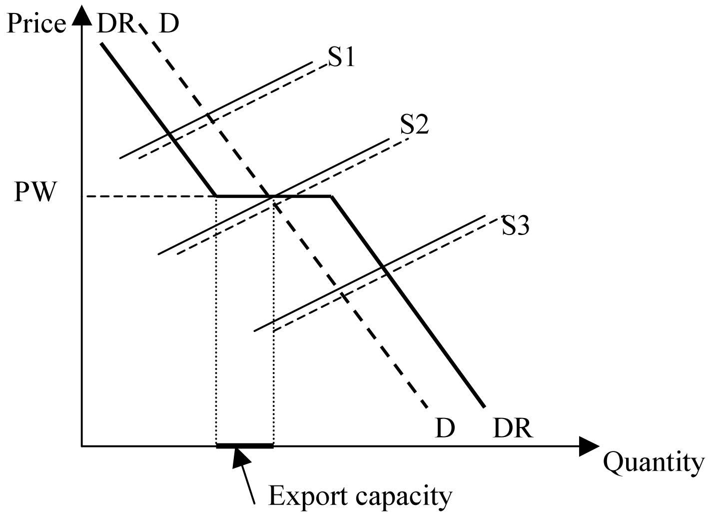
1 Introduction

For decades, Norwegian politicians have debated domestic utilization of natural gas for electricity generation. Still, there is no generation of electricity from natural gas at mainland Norway. Large gas volumes are exported to central Europe. In 1999, the export value was about 3 billions US$. The discussion of gas power expansion reached a climax in March 2000, when Prime Minister Bondevik denied issuing gas power generators concession and emission permission. Mr. Bondevik left office when depressed by the parliament's majority. Bondevik and his government argued that Norwegian gas power generation would increase total emissions of climate gases in northern Europe as a whole. The majority in the parliament voted in favor of concession. As a consequence, the Labor party's Mr. Stoltenberg became new Prime Minister. Mr. Stoltenberg's argument is that domestic gas power will replace imports of electricity generated in old oil and coal plants with low energy efficiency. Thereby, gas power in Norway will lower climate gas emissions and result in a cleaner environment.

The political discussion then has focused on whether Norwegian gas power plants will substitute foreign coal-based power generation and thereby reduce emissions of climate gases or not. The profitability of gas power generation itself has not been that heavily discussed as politicians seemingly intend to leave this question to the potential investors.

Similarly, we focus on the generation mix and environmental consequences and not economic profitability of new gas power. However, we simulate equilibrium prices, which implicitly reflect profitability or not. In figure 1, we sketch the principal impacts in the Norwegian power market from introduction of a new gas power plant.

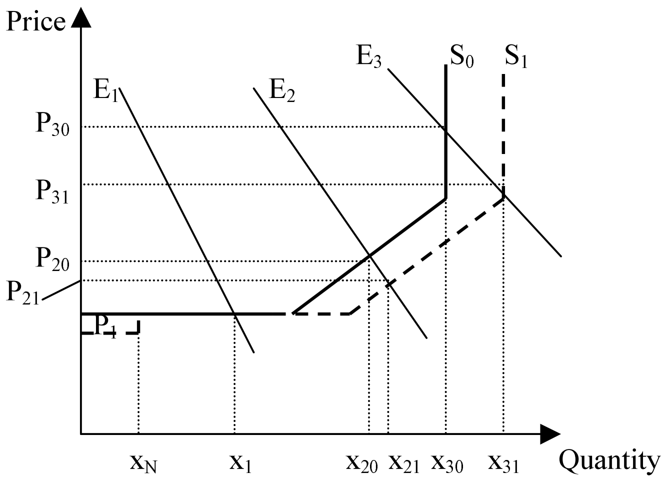
Figure 1 Impacts on the domestic power market from increased gas power supply



The figure is a common price and quantity diagram with a demand curve for electricity (D-D). Norway is an open electricity market with some grid capacity to neighboring areas. The price in this international market is PW. Domestic prices above PW lead to full import defined by the grid capacity and domestic prices below PW lead to full export. Subtracting maximum import from the demand curve for prices above PW and adding maximum export to the demand curve at price levels below PW leaves us with a residual demand curve directed towards domestic suppliers. This residual demand curve is the DR-DR curve. We illustrate three different supply curves, S1-S3. Each has a solid line, indicating the supply at the outset, while the dotted lines illustrate the supply after the additional supply capacity, for instance gas power.

In the cases with the supply curves S1 and S3, increased supply leads to lower prices, increased demand and some substitution at the supply side. If the supply curve is vertical, as may be the case in the Norwegian hydropower market, there will be no supply substitution and the additional supply will be absorbed by increased demand. It is easy to see that increased supply in Norway in case S1 or S3 does not affect the imported or exported power volumes. Therefore, in these two cases there will be no effects abroad from new gas power in Norway. In the middle case with a supply curve equal to S2, the domestic price is fixed and equal to the price in neighboring countries. Therefore, domestic demand is not affected when supply is increased. All additional supply is exported or replace (reduce) imports. Consequently, increased domestic supply has impacts on neighboring power markets. These impacts depend on the market situation in Norway's neighboring countries. In figure 2, we sketch some possible outcomes.

Figure 2 Price and quantity impacts in Norway's neighboring countries



Before the new Norwegian gas plant is established, the solid line, S_0, indicates the supply curve in neighboring countries. The supply curve is horizontal at low (constant marginal cost) production levels, upward sloping at intermediate production levels and vertical when the capacity is fully utilized. The supply curve includes some imports from Norway (or it is net of export to Norway). We illustrate the impacts from reduced exports or increased imports for three different demand levels by using three alternative downward sloping demand curves, E_1 to E_3. Before gas power is introduced in Norway, the equilibrium production quantity and price pairs are (x_1, p_1), (x_{20}, p_{20}) and (x_{30}, p_{30}). We introduce increased imports from Norway to neighboring countries (or reduced exports from neighboring countries to Norway) by adding the volume (x_N) to the old supply curve. The supply curve shifts towards right and the new supply curve S_1 is given by the dotted line.

The price and quantity impacts depend on the location of the demand curve. If demand is low (E_1), price does not change, and total consumption and generation are not affected. The new gas power completely substitutes old generation. When demand (E_2) crosses the upward sloping supply curve, increased supply leads to a price reduction and increased electricity consumption. However, consumption increases less than the imported power volume. Consequently, increased imports partly substitute existing generation and partly are consumed. When demand is high (E_3), imported quantity is completely absorbed by increased consumption. In this case, the new gas power does not substitute any old generation.

Figure 1 and 2 show that the effects upon power production, demand and emissions of introducing gas power plants in Norway depend heavily upon the initial supply and demand conditions. Deregulation of the Nordic electricity market has revealed excess power production capacity. In many periods of time, the marginal technology is thermal power based on coal. Excess capacity means that the actual demand crosses the supply curve at the horizontal or near horizontal part of the supply curve. However, over time the excess capacity diminishes according to depreciation and demand growth. When the excess capacity is reduced, the market may more often be characterized by the situations illustrated by the demand curves E_2 and E_3 in figure 2. In the long run, market prices reach long-term marginal costs of new capacity and the supply curve is horizontal or upward sloping. Then, we are back in a situation where new gas power in Norway substitute marginal capacity expansions in neighboring countries.

In order to receive proper answers to the question raised above, we rely on simulations of an empirical model for the actual market. We analyze the economic and environmental consequences of introduction of gas power generation in Norway. We apply Statistics Norway's equilibrium electricity market model for the Nordic area, Normod-T. The model describes power generation, consumption and trade in the Nordic area and between the four Nordic countries Norway, Sweden, Denmark and Finland and Germany.

The paper is organized as follows. In the rest of the present section, we give a short background on the Nordic electricity market and its organization and structure. In section 2, we discuss the model, while parameters and exogenous variables are shown in section 3. Section 4 includes calculations, results and sensitivity analysis, while the final section contains main conclusions.

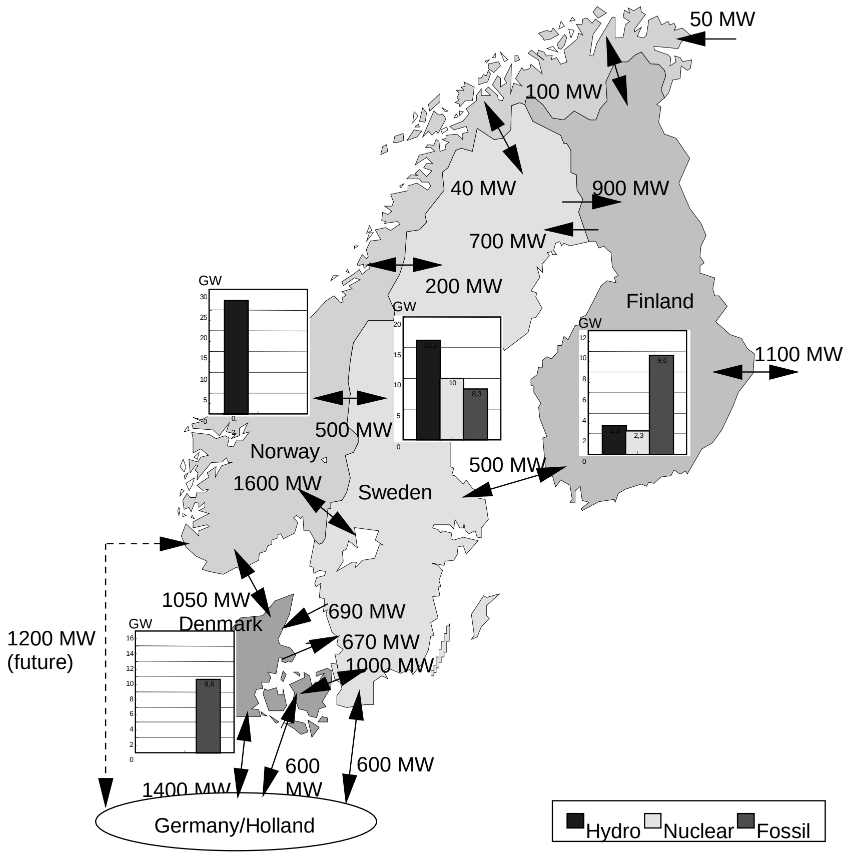
1.1 Background

Three Nordic countries, Finland, Norway and Sweden, have deregulated their electricity markets, see for instance Bergman et al. (1999). In the fourth country, Denmark, only end-users or distribution companies with an annual demand of 100 GWh or more are today free to purchase electricity from others than their local utility. Denmark is expected to liberalize further in a few years. However, Danish electricity producers are already trading intensively at the Nordic power exchange (Nord Pool).

Third-party access to the networks and competition among generators and suppliers are the main elements of the reforms in all countries. End-users, traders, brokers, distributors and generators participate in the electricity trade at Nord Pool on a voluntary basis. The spot prices of electricity express the marginal value of power and are important for price setting outside the exchange and for end-user price movements. Network activities are separated from generation and sales activities and regulated by national regulatory bodies.

The total production of electricity in the Nordic area in 1998 was 377 TWh, hydropower being some 55 per cent, nuclear power 25 per cent, and thermal power 20 per cent. Figure 3 illustrates the main physical features of the Nordic electricity system.

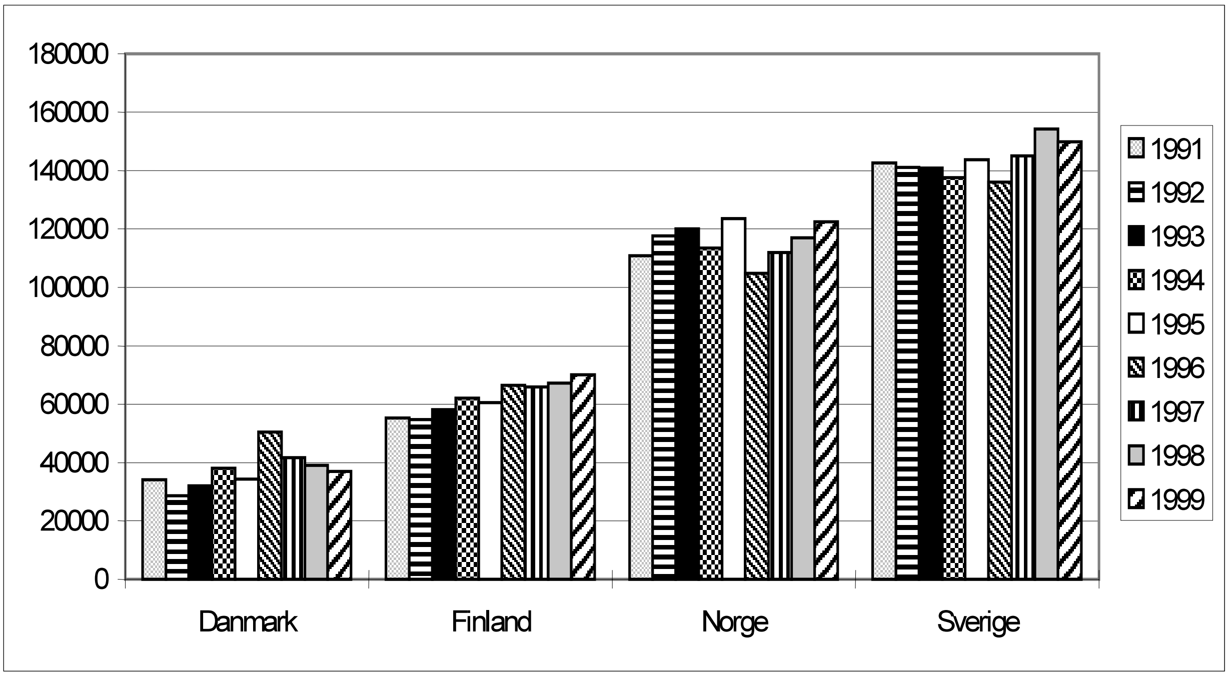
Figure 3 The Nordic electricity system. Transmission and generation capacities



The composition of the national electricity generation systems is important for the attractiveness of power trade among the countries. Finland and Sweden have diversified power generation systems, while the Norwegian and Danish power systems are less diversified, although quite different. In Norway, electricity generation is purely based on hydropower. In Sweden, electricity is produced from hydro, nuclear and as industrial co-generation or in combination with small-scale heat production. Finland has hydro-, nuclear- and coal-based power and de-central combined heat and power generation based on fossil fuels or bio-fuels.[1] In Denmark, condensing and combined heat and power based on coal are the dominant technology, while planned expansions will be based on natural gas, bio-fuels and wind.

Because different generation technologies have different marginal production costs there is a large potential for electricity trade between the Nordic countries. Energy Policy measures introduced in one country may therefore have huge impacts on the Nordic electricity trade and Nordic electricity prices. There exist a strong interdependence between the national markets, and incidents in one country affect surrounding markets as well. An illustration of these interdependencies is given in figure 4. Norwegian and Swedish hydropower generation vary heavily as precipitation and snow melting vary. The hydropower generation may vary with as much as +/- 25 percent from one year to another. Figure 4 shows yearly power generation in the four Nordic countries in the period 1991-99.

Figure 3 Annual power generation in the Nordic countries, 1991-99. GWh



There is a strong negative correlation between Norwegian (hydro) and Danish (thermal, coal) generation. There is a clear similar pattern between Sweden and Denmark and between Sweden and Finland. This, certainly underlines the simultaneous determination of Nordic power generation. Power

[1] Biofuels are wood, peat, straw and waste.

is produced from the cheapest source available and generation shortfalls in one country are replaced by production in the other countries.

The variation in annual generation and electricity trade affects the levels of polluting emissions as well. All the countries with some thermal power capacity (Denmark, Finland and Sweden) emit more CO_2 in the years with low hydropower generation than in years with normal or above normal hydropower generation. The variation in generation and emissions shows how interrelated the national power markets in the Nordic area are and how important proper design of the energy policy is. New Norwegian gas power generation will more or less have the same impacts as surplus hydropower generation. However, there are differences, as the additional hydropower generation in a wet year often has to be produced during the summer and autumn while gas power will produce the entire year except for a maintenance period when prices are low (summer). While hydropower has an operating cost close to zero, gas power has much higher variable costs. In addition, a gas power plant is less flexible than a hydropower plant with respect to start and stop of generation. Consequently, we can not use figure 3 to draw strong conclusions about the impacts from Norwegian gas power on Nordic electricity balance and generation mix. We strongly need a model of the electricity market and generation system to calculate likely impacts from new gas power generation in Norway.

2 Model

In order to simulate the consequences of Norwegian gas power production for Nordic electricity prices, consumption, generation and climate gas emissions, we use Statistics Norway's equilibrium model for the Nordic electricity market, Normod-T.[2] The model assumes perfect competition and has 12 different time segments during the year and includes 5 demand groups in each of the 4 countries; Norway, Sweden, Denmark and Finland. For each country we specify a large number of existing and new generation capacities with accompanying capacities, fuel prices, fuel conversion rates, heat prices, other variable and expansion costs. In addition to electricity trade among these countries, we model these countries' electricity trade with countries outside the Nordic region.[3]

Figure 5 shows the main blocks of the model.

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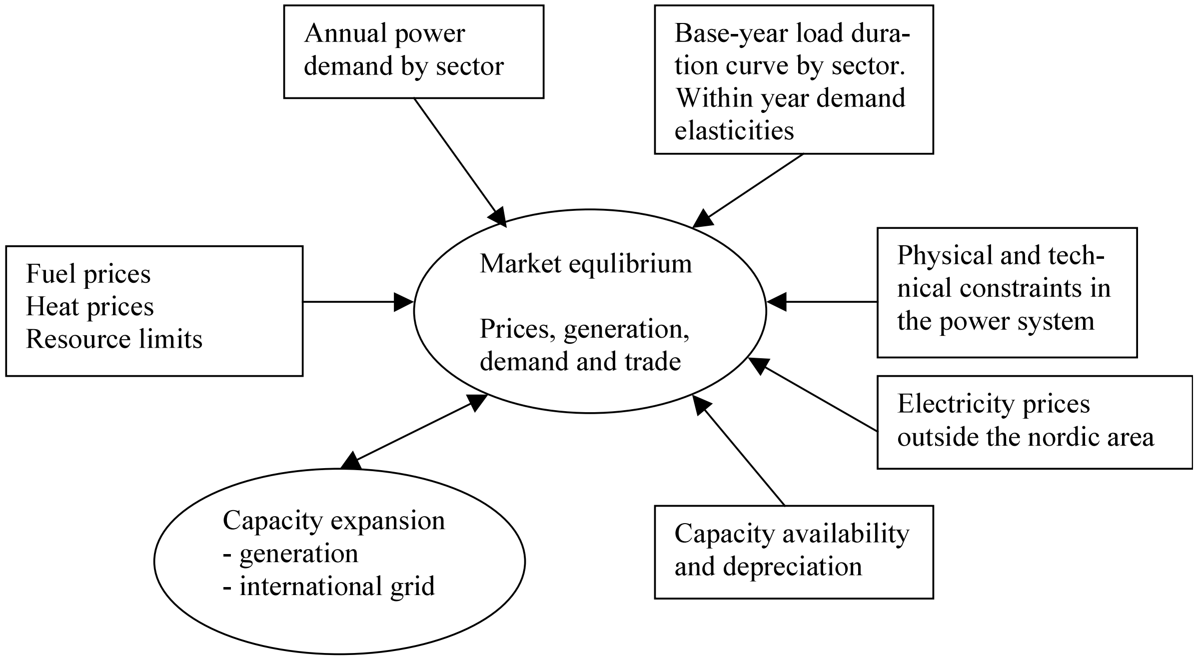
[2] See Johnsen (1998) for a documentation of the model and data.
[3] Russia, Poland, Germany and The Netherlands.

Figure 5 Model overview Normod-T

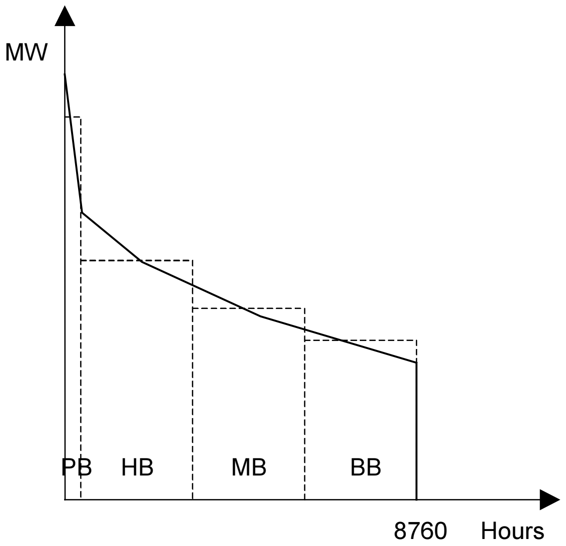


The main driving forces are economic growth, depreciation of old generation facilities, fuel and heat prices, costs of new technologies and the development of electricity prices outside the Nordic area. The model calculates equilibrium electricity prices, electricity generation by technology and fuel and electricity trade for all countries and periods. A large number of physical constraints such as generation capacities, maintenance levels, security margins, water flow limits and transmission capacities, and utilization times limit the model solution. Each binding constraint reflects a shadow price in terms of a marginal value of a less strict constraint or the marginal cost of a more tight constraint. For instance, when there is no transmission congestion among the countries, the equilibrium electricity prices will only differ with variable transmission costs. If a path gets congested, there will exist a shadow price of that path's capacity and national prices differ.

Electricity demand - load blocks

Electricity demand varies heavily by time of day, week and year. This variation implies large variation in the generation capacity utilization and costs. As shown in figure 1 above, impacts from new gas power depend heavily on the demand and the capacity utilization rate. Therefore, our model has four demand periods or load blocks during each season. Figure 6 illustrates hourly demand in a power system during one of the three seasons, where the hours are ranked from left to right according to the load demand (*load duration curve)*.

Figure 6 Illustration of a load duration curve and four demand (load) blocks



For each country, it is assumed a four-step decreasing curve, illustrated by the dotted columns in figure 5. We denote each column a block and the four blocks are; base (BB), medium (MB), high (HB) and peak-block (PB). The first three blocks are assumed to have equal length, while the peak block is of shorter duration.[4]

A large macroeconomic applied general equilibrium model for the Norwegian economy, MSG-6, see Holmøy et al. (1999), is used to calculate annual electricity demand growth for Norway, while demand growth for Sweden, Denmark and Finland is exogenous.[5] For each demand group, the yearly electricity demand is distributed on seasons and load blocks) according to base year coefficients and the development of the end-user power price for each block.

Electricity generation and costs - load modes

We specify about 25 existing and new power-generating technologies in the model by capacity, variable and fixed costs, fuel type and price and fuel conversion efficiency. The utilization time of

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[4] The length of the blocks is (hours):

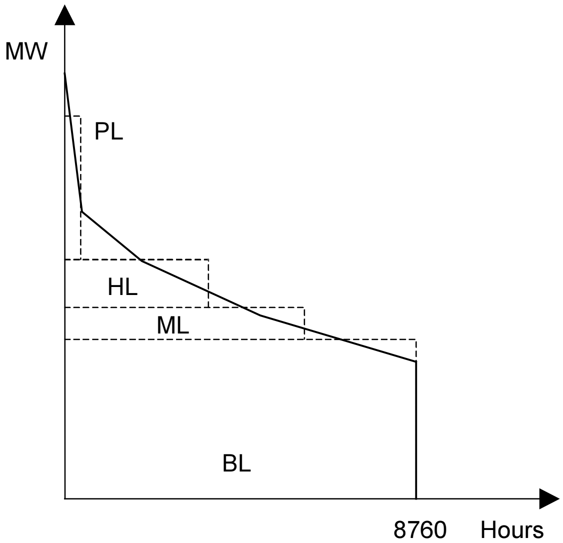
Season	Base block	Medium block	High block	Peak block
W1	1124	1124	1124	252
SU	910	910	910	198
W2	683	683	683	159

[5] Through an iterative procedure, we run MSG-6 and Normod-T in order to find a consistent path for yearly electricity prices and aggregate electricity demand in Norway. For the other Nordic countries, we assume the same macro price elasticity with respect to the annual average of the electricity price as found through the iterative process with MSG-6.

technologies is crucial in determining their marginal cost and long-term profitability. The longer the utilization time is, the lower is the capital cost per produced unit. In addition, there are large differences across technologies with regard to their ability to vary output. One extreme is nuclear power plants, in which the output can only be regulated within a narrow interval. On the other hand, hydropower plants are cheap to regulate. New gas power in Norway will supplement the hydropower generation and have impacts on the electricity trade pattern between Norway and other countries. If the hydropower flexibility is large enough to allow the new gas power to run as base load generation the marginal cost of gas power will be at its lowest level. Therefore, it is important to recognize the generation technologies' utilization time and whether the plants operate in base load or are stopped and started over the course of a day or week. In the model, the utilization time is endogenous.

On the margin, new gas power in Norway will compete with foreign generation only if there is spare transmission capacity between Norway and the other countries. To capture utilization times and the variation in flexibility among technologies, we specify four load modes, see figure 7.

Figure 7 Load duration curve and four load modes



The load duration curve is the same as in figure 6. However, when looking at generation decisions, we specify modes equal to the four horizontal rectangles in figure 7. For a thermal power generator, start and stop considerations and cycling (lower than full capacity utilization in running plants) are important questions. If, for instance, base-block prices are low, some generators may want to stop during base-block and thereby produce only in the medium-load mode. An alternative is to run a low capacity utilization during the base-block and thereby avoid a complete stop of the plant. In our model, these two features are handled in a simplified way. For each season *s* and load mode *h e*ach generation technology (*k*) in country *l* has an operating cost (OC) given by

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

where q is the fuel input price measured in Nkr/kWh, ph is the exogenous price of heated water in Nkr/kWh, while $\bar{\mu}$ is the total fuel conversion efficiency (electricity and heat) and μ is the fuel conversion efficiency in electricity generation. For technologies producing only electricity, $\bar{\mu}$ is equal to μ. The two α's are variable costs other than fuel costs (α1) and start-up costs (α2).

The α2-term in equation (1) is mode specific and =0 if h = base-load (BL), >0 if h = medium (ML), high (HL)- or peak-load (PL). A technology not used in base-load generation has to be started daily and the estimated start-up cost is divided on the number of hours of operation in order to receive an estimate for α2. In addition, we allow fossil fuel based plants to reduce capacity utilization to 60 percent during base-block.

The load duration approach implies grouping of hours within load demand intervals. For example, the high period consists of hours that not necessarily follow each other in chronological time. Thus, the load duration approach suppresses the chronological aspect of the variation in demand and supply. Kahn et al. (1992) point on the shortcomings of the load duration approach compared to a chronological approach. With chronological time, start and stop decisions and cycling may be described in detail.

Operating costs in hydropower plant are very low, but a number of physical constraints and institutional constraints given through the concession to operate limit the operational flexibility of the hydropower generation equipment. We apply a lower limit for hydropower generation, which is motivated from two facts. First, due to heavy snow melting, the water inflow to river stations is high for some part of the summer. All this inflow can not be stored, and will be lost if not produced when arriving to the stations. Second, for each separate watercourse, the Norwegian Water and Resource Administration (NVE) determines a minimum flow of water. In each season, the base load hydropower generation has to be equal to or greater than a lower limit. Although hydropower production can be regulated up and down at low cost, there may also be constraints on the variation over the day, or between the base and peak generation. In our model, we apply an upper limit on the increase in hydropower generation from base to peak load mode. Finally, there is an upper limit on the reservoir capacity, or on the aggregate generation of energy from hydropower resources in the two winter periods.

Solution of the model

An optimal solution of the model is found by maximization of the yearly sum of producer and consumer surplus over all seasons and load periods and all countries given capacities and constraints.[6] In the short-run generation and transmission capacities are fixed. We depreciate old generating equipment linearly by exogenous rates. In the long run, transmission and generation investments will take place if profitable. In the model, new generation capacity is established if power prices on average over a year exceed long run marginal costs for new capacity. Long run marginal costs include capital costs, fuel costs and other variable costs. Only a very few new investments will be available before 2004, because of long planning and construction lags and a very little investment activity at the moment. We update capacities yearly by depreciation and new investments. Relative prices and transmission capacities determine the power trade between Nordic and other North-European countries.

3 Data and assumptions

In our scenarios, the electricity sector proceeds from today's starting point without major changes in the energy policy. Denmark's deregulation will be completed very soon and a gradual deregulation is expected in Germany and other neighboring countries.

Electricity demand

Our demand equations are linear in economic growth and prices. We apply base-year observations for demand and prices and a set of elasticities to calibrate the price derivatives in the demand equations. We do not have time-series for seasonal and daily demand variations so econometric estimation of elasticities has not been possible. Therefore, our elasticities are based on estimates published by other sources, i.e. Amundsen et al. (1997) and Nesbakken (1998), see table 1.

[6] We use the solver Minos5 to solve our GAMS model, see Brooke et al. (1992).

Table 1 Price elasticities used to calibrate the demand equations

	Winter				Summer			
	Base	Medium	High	Peak	Base	Medium	High	Peak
Metal	-0.2	-0.3	-0.3	-0.10	-0.2	-0.2	-0.2	-0.2
Pulp&paper	-0.2	-0.3	-0.3	-0.10	-0.2	-0.2	-0.2	-0.2
Other ind.	-0.2	-0.3	-0.3	-0.15	-0.2	-0.2	-0.2	-0.2
Services	-0.3	-0.4	-0.4	-0.3	-0.2	-0.3	-0.3	-0.3
Households	-0.3	-0.4	-0.4	-0.3	-0.2	-0.3	-0.3	-0.3

Except for the peak block, the summer elasticities are lower than, or equal to, the winter elasticities. In the winter season, a large fraction of the electricity consumption is used for space heating. More substitutes are available for space heating than for use of electricity in technical appliances, which represent a larger part of the electricity consumption in the summer season.

The peak block elasticities for the winter season are treated in a special way. Since our demand equations are linear, the price elasticities increase with increasing prices. In our scenarios, the highest prices occur in the peak block in the winter season and when calibrating the price derivatives, the peak elasticities are reduced to avoid too high price elasticities at high price levels.

For the metal and pulp and paper sectors, an additional fact motivates the lower elasticities in the peak block. These production processes in these industries should be run at a steady speed both with concern to technicalities and profitability. A high price in the peak block hours will not necessary lead to a large reduction in electricity consumption, because it may be more costly to close down the production than to pay a high price in the peak block. Instead, the average price level over a longer period, determines whether they produce or not.

With one exception, the price elasticities are the same in all four countries. Danish households face electricity prices which due to taxes are two times as high as the prices in other countries. Electricity is also only to a small extent used for space heating in the Danish residential sector. Thus, we assume that the possibility of substituting away from electricity is less than in the other Nordic countries. Therefore, the elasticities for Danish households are 50 percent lower than the elasticities listed in table 1.

Generation costs
We assume constant real fuel prices during the simulation period, see table A1 in the appendix. Denmark is a large and experienced coal buyer and has the lowest coal prices in the model. Biofuels (wood and peat) are a well-established energy source within short transport distances in Finland. Natural gas deliveries through existing pipelines have lowest price in Norway (located close to the North Sea) and in Finland (import of Russian gas). We assume additional gas volumes to be available from the Norwegian gas fields Troll and/or Haltenbanken. Gas from these fields to power plants is then cheapest in Norway, while transport margins lead to somewhat higher plant prices in the other countries. The other variable costs are shown in table A2.

Table A3 shows capital costs and fuel conversion efficiencies by technology. All technologies are not available in all countries. Denmark, Finland and Sweden have already networks for district heating, while such systems are very limited in Norway. We assume exploration and/or transportation costs to prevent peat-fuelled power generation in Norway and Denmark. New waterfalls available for development are located in Norway.

Table A4 shows our assumptions about heat prices in the Nordic countries. In order not to overestimate the value of heat production, our estimated heat prices are considerably lower than the heat price used in Olsen and Munksgaard (1996). The potential for cogeneration of heat and power varies. While cogeneration covers 65-75 percent of the district heating production in Denmark and Finland, cogenerated *heat* accounts for only 25 percent in Sweden, see Olsen and Munksgaard (1996). The fraction of cogenerated *power* differs also highly across the countries. Today, pure heat plants supply the Swedish district heating systems. Therefore, there is a large potential for cogeneration. Table A5 reports the potentials for cogenerating power capacity.

Existing and new natural gas pipelines and restrictions on national resource extraction limit the supply of fuels for use in conventional thermal power plants, see table A6.

Wind and hydropower have long lifetimes and are not depreciated during our simulation period (2000-2010). Swedish nuclear power capacity is held at 64 TWh from 2002 (Barsebäck I and II are deducted). In average, existing thermal capacity has a residual lifetime of about 15 years in 2000. On this basis a 7 percent annual depreciation may sound reasonable. However, we have chosen to depreciate at a slower rate. International experience suggests that thermal power plants often last for a significantly longer time period than initially assumed, see Ellerman (1996). Therfore, we start depreciation in 2002-2004 at an annual rate of 3-4 percent.

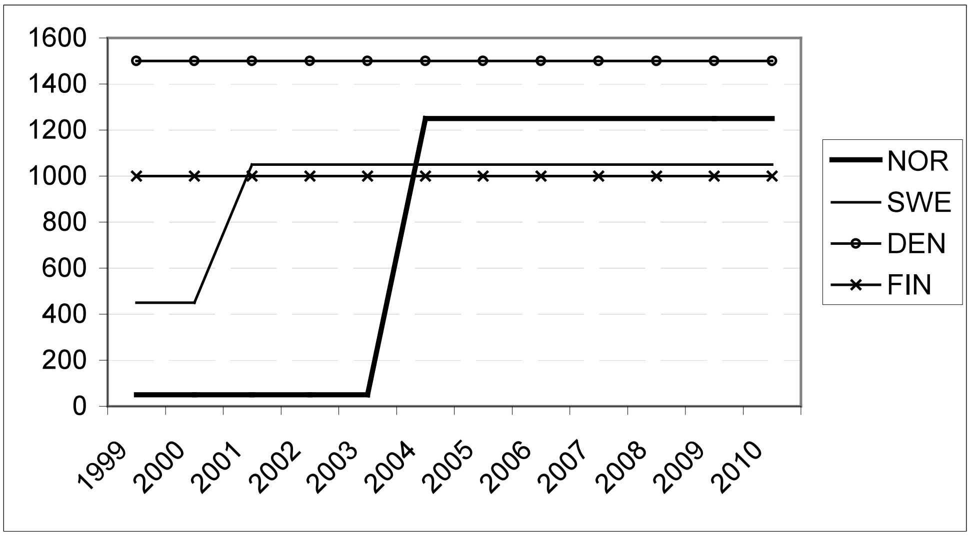
In Norway, we limit hydropower expansion until 2010 to 8 TWh. Based on information available in January/February 2000, Norwegian hydropower generation is assumed to be 116 TWh in 2000. However, when this is written it is clear that water inflow and snowfalls during winter 2000 has been much richer than initially assumed. The figures reported for 2000 should be viewed in this light.

International electricity trade and prices

Table A7 lists the marginal costs of electric transmission among the Nordic countries, current capacities and expansion costs.

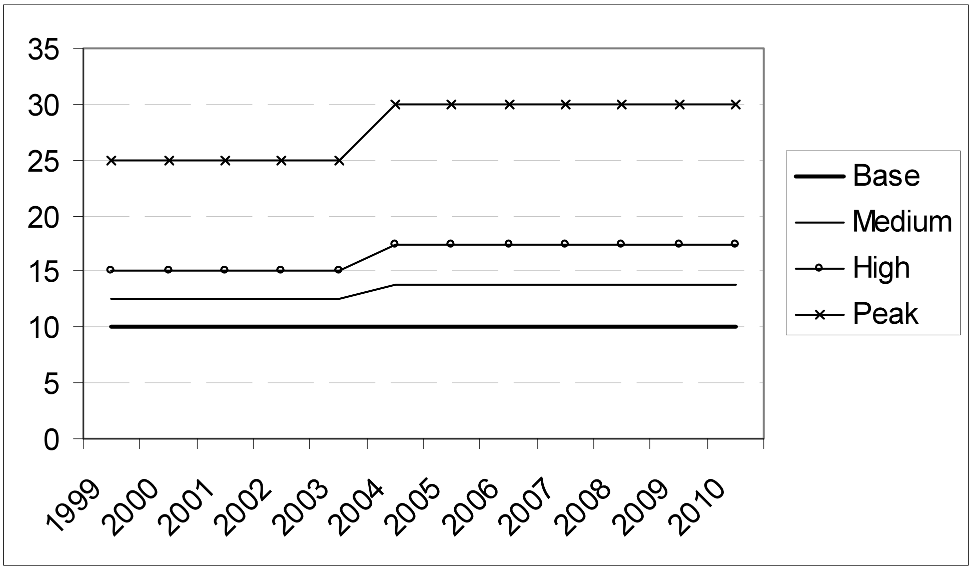
The trade between Nordic countries and countries outside the Nordic area is crucial for the simulation results. Figure 8 shows the transmission capacity between each Nordic country and countries outside the Nordic area during our simulation period.

Figure 8 Transmission capacity out of the Nordic area, MW



While Denmark and Finland have unchanged capacity to Germany and Russia (1500 and 1000 MW), a new cable between Sweden and Poland operates from 2001. In addition, we assume two planned 600 MW cables between Norway and Germany to operate from 2004.

Figure 9 Power price development in countries outside the Nordic area. øre/kWh[7]



Peak block periods are short and are of moderate importance for aggregate trade volumes and domestic prices. The base, medium and high block prices are most important. Outside the Nordic area, we assume base block prices to remain at 10 øre/kWh towards the end of the simulation period. Thermal power dominate neighboring countries' power systems and we assume base block prices to remain low simply because a number of producers find it profitable to run in base load mode and thus supply power during the base block period instead of taking daily start and stop costs. Medium and high block prices are 25 and 50 percent above the base block price. Finland's non-Nordic transmission lines goes to Russia. We assume Russian power prices to stay low for a longer period than in central-Europe. Therefore, we assume Russian prices to vary less and to continue to be low for a longer period than prices in central-Europe do.

4 Results

We simulate two scenarios, one without new gas power in Norway, Nogas, and one scenario with gas power in Norway, Gas. In the Gas scenario, we include two large-scale combined cycle gas power plants (375 MW each) with a total annual generation capacity of 5.6 TWh. In the analysis, we include these plants irrespective of their profitability in order to study the impacts on the rest of the market. Additional gas power plants in Norway have to pay the opportunity gas cost or the "world-market" gas price given by table A1.

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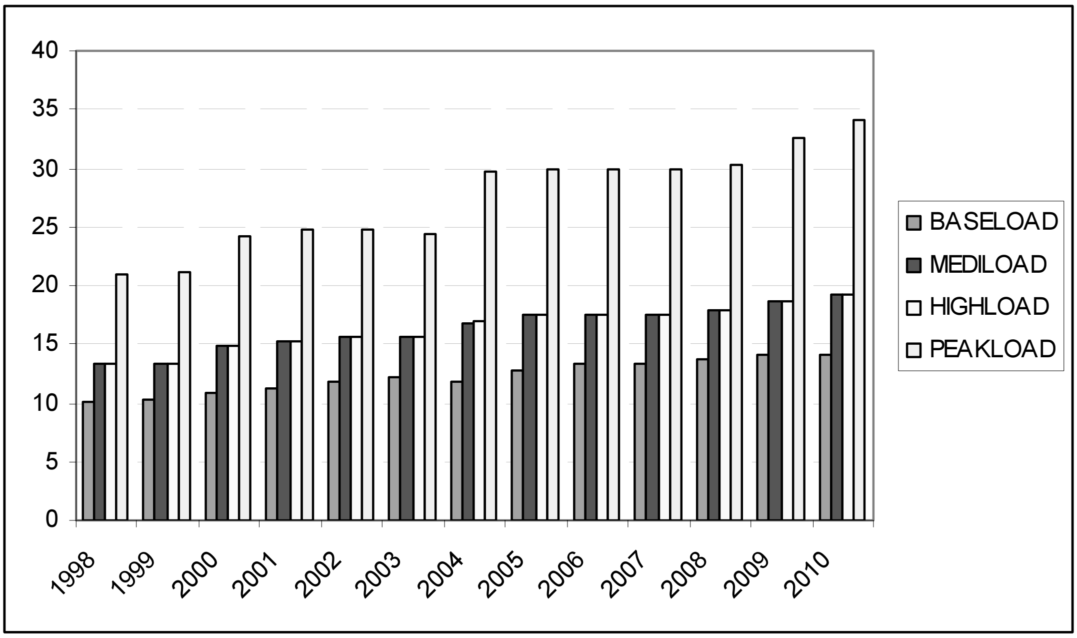
[7] 100 øre = 1 Nkr = 0.12 US$

In the Nogas case, Nordic power prices increase year by year due to demand growth, depreciation of generation equipment and thereby a more tight market. Some cheap hydropower and various combined heat and power plants are developed during the simulation period, and net imports from countries outside the Nordic area increase. By the end of the simulation period prices have reached the long-term marginal cost of combined cycle gas turbine plants without heat utilization. Figure 10 shows the development of Norwegian power prices for each separate load block until 2010.

Figure 10 Norwegian power prices in the Nogas case by load block. øre/kWh

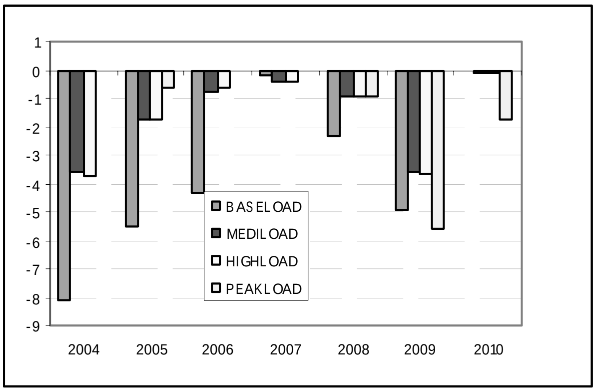


Norwegian annual average power prices increase to about 15 øre in 2000 since 1998 and 1999 was wet and we expect precipitation and temperatures to be close to normal in 2000 and normal from 2001. However, surplus capacity and low prices in Norway's neighboring countries keep imports high and Norwegian prices low until 2003. From 2003 to 2004, the assumed price growth in countries outside the Nordic area causes Norwegian prices to increase as well. While medium and high block prices are equal, base block prices are lower and peak block prices higher than prices in intermediate blocks. Despite the high flexibility and regulation ability of hydropower Norwegian prices differ across load blocks. The reason is physical constraints on how much the aggregate hydropower generation may be varied over the day. In our model, peak block generation is constrained to be no more than 90 percent higher than the base block hydropower generation because of limits on the variation in water flow over the day. Increased hydropower generation during the base block allow higher peak generation to good prices as well. This extra payment for base generation lowers the marginal cost of base generation and base block equilibrium prices fall.

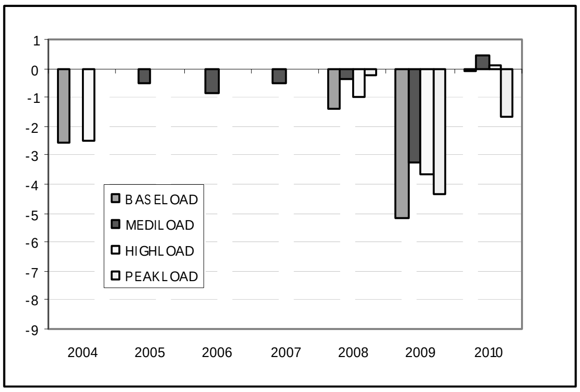
In figure 1 we discussed how new gas power in Norway could affect the electricity prices under various market situations. Figure 11 shows price changes in Norway and Denmark as the two new Norwegian gas power plants are introduced.

Figure 11 Price change by load block from the Nogas to Gas case in Norway and Denmark. Percent

Norway



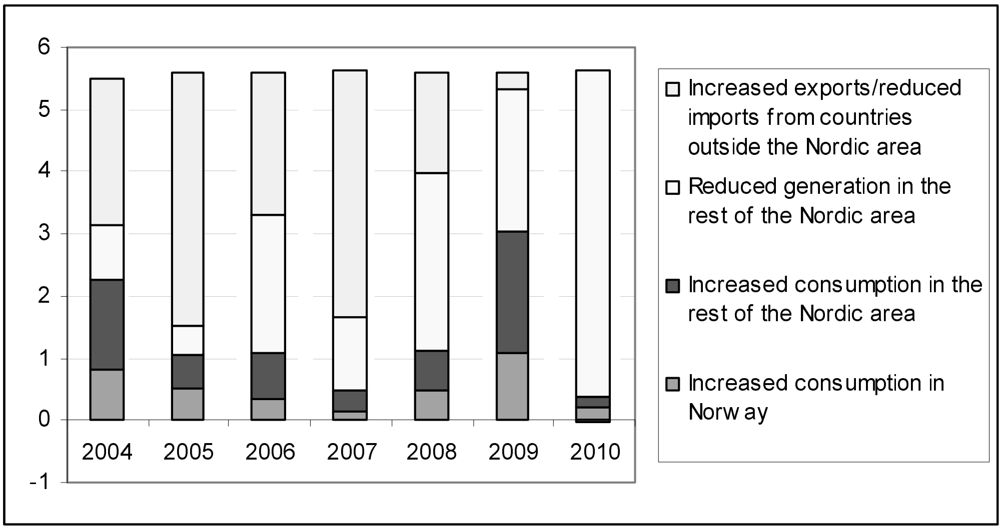
Denmark



In most years, base block prices show the sharpest price-fall since the additional power volume in this period is largest compared to the demand level. Medium and high block prices fall as well but not as much as the base block price. Until 2009, Norwegian prices change more than Danish prices indicating frequent transmission constraints. The differences between the Nogas and Gas cases are large in the beginning of the period and then reduced until 2009 when the differences increase again. During the period 2004-2008, old generation capacity depreciates and investments in some new power plants, mainly CHP and hydroelectric plants take place. At the same time demand increases and there is a steady growth in the imports and reduction of exports to countries outside the Nordic area. These movements lead to less transmission congestion, more equal prices across countries and more dependence on imports from countries outside the Nordic area. Consequently, the price impacts from new gas power in Norway is gradually reduced. The picture changes dramatically in 2009. In this year Nordic power imports from other countries reaches the transmission limit. Therefore, new gas power from Norway does not alter trade with countries outside the Nordic area and all the gas power is to be absorbed by the Nordic market. In 2009, the Nordic power market is at an upward sloping or in some periods the vertical part of the aggregate Nordic power supply curve, which implies that prices have to fall to clear the market. In 2010, demand and prices is even higher, and we have reached the level of the long-term marginal cost for gas power. In this situation, new gas power in Norway replaces new gas power in Sweden and prices change very little. These mechanisms may be illustrated by a decomposition of quantity changes following the introduction of new gas power in Norway. In figure 12, we show to which extent the new Norwegian gas power leads to:

- Increased power consumption in Norway
- Increased power consumption in other Nordic countries
- Reduced generation from other power sources
- Increased exports/reduced imports from non-Nordic countries

Figure 12 Decomposition of impacts when 5.6 TWh new Norwegian gas power is fed into the Nordic power market. TWh

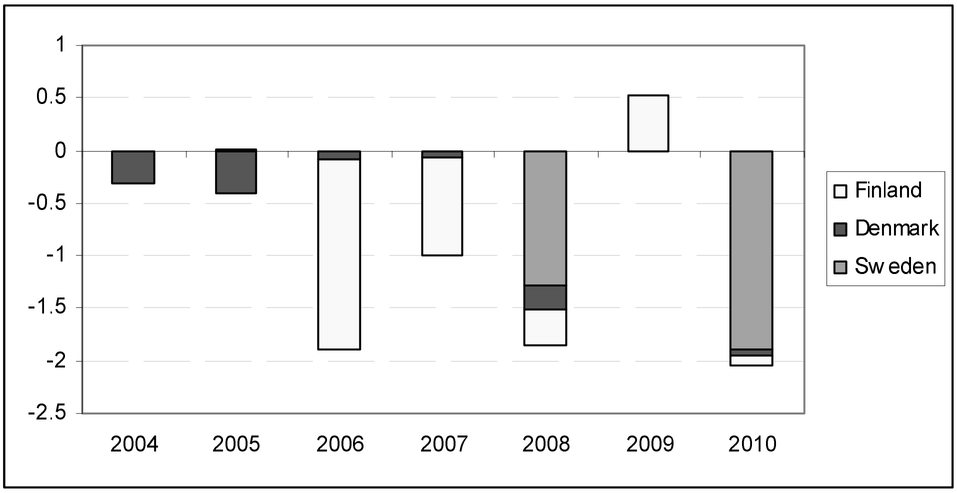


Increased Norwegian and Nordic electricity consumption absorbs between 0.5 and 3 TWh of the gas power volume and the pattern mirrors the pattern of the price changes in figure 11. Norwegian power generation from other sources does not change when gas power is introduced. Generation in the other countries, however, changes. Marginal technologies are substituted and before 2009, Norwegian gas power substitutes Danish coal, Swedish oil and Finnish oil and coal based power. By the end of the period, Norwegian gas power replaces gas power in Sweden and Finland. The slope of the supply curve and the capacity utilization of transmission lines to non-Nordic countries determine the magnitude of the substituted volume. In 2005 and 2007 relative prices and transmission capacities between the Nordic area and non-Nordic countries are such that inclusion of new Norwegian gas power leads to a change in net power exports from Nordic countries and non-Nordic countries of about 4 TWh. In 2004, 2006 and 2008 net Nordic power exports increase with only 2 TWh. In 2009 and

2010, there is hardly no change in the trade out of the Nordic area since import capacities are near full utilization both in the Nogas and in the Gas scenario.

When Norway produces 5.6 TWh new gas power, Norwegian CO2 emissions increase with 2.2 million tons. As the Norwegian generation to some extent substitutes Swedish, Danish and Finnish oil, coal and gas power generation, emissions from these countries' power sector change, see figure 13.

Figure 13 Change in CO2 emissions from power generation in Sweden, Denmark and Finland from the Nogas to Gas scenario. Million tons

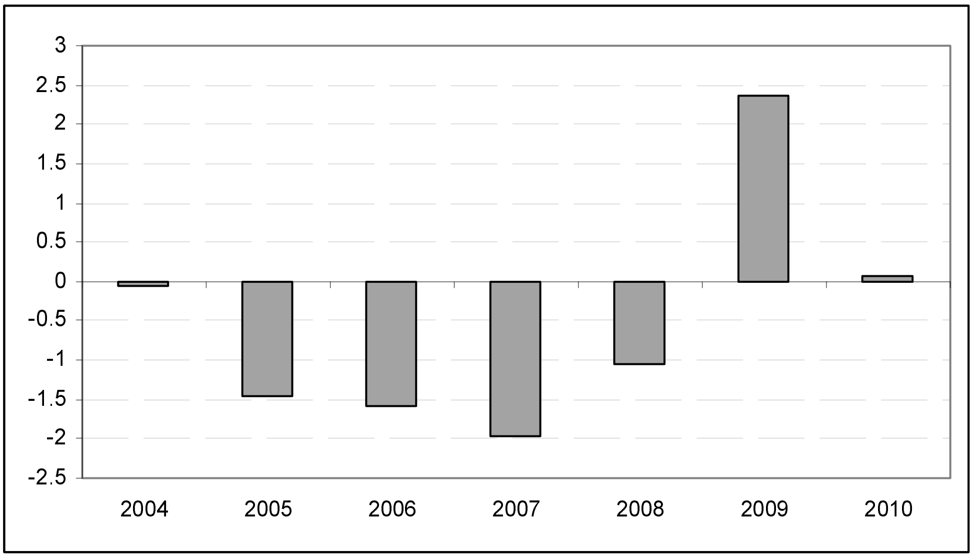


During the first two years, Norwegian gas power replaces Danish generation, while in 2006 and 2007 it is Finnish emissions from oil and coal power that decrease. In 2008 and 2010 it is mainly Swedish generation that is substituted. In 2008 the Norwegian gas power replaces some Swedish oil based power, while it replaces new Swedish gas power capacity in 2010. In 2009 Finnish emissions increase when gas power is introduced in Norway. The increase in Finnish emissions stems from a change in the power production technology mix in Finland from the Nogas to the Gas case this year. In the gas case, Norwegian power export to Sweden increases and Sweden re-exports a large share of this power volume to Finland. In aggregate, Finland's net import rises from 2.1 TWh in the Nogas scenario to 4.8 TWh in the Gas case in 2009. This change leads to a shift from gas power (-4.8 TWh) to oil based power generation (+2.4 TWh) in Finland. Both technologies utilize the heat but co-generation in old oil based plants give less electricity per heat unit than gas based co-generation in new plants. The lower electricity prices in the Gas scenario than in the Nogas scenario prevent (delay) investments in new gas co-generation and instead some old oil co-generation capacity becomes profitable.

When adding the emission changes in figure 13 to the initial 2.2 million tons increase in Norway, we see that emissions from aggregate Nordic power generation increase in all years. The net increase is, however, close to zero in 2006, 2008 and 2010.

While our model threats the Nordic power market in some detail it does not include emission changes in non-Nordic countries when the net Nordic power exports change. While the Finnish import from Russia not is affected, Swedish, Danish and Norwegian trade with Poland, Germany and The Netherlands often change when new gas power is produced in Norway. There are a number of possible effects. As shown in figure 2 above, increased Nordic export may replace, add or partly replace and add to the existing electricity generation in non-Nordic countries. If Nordic exports replace non-Nordic generation, emission changes depend on the emissions from the marginal power generation technologies. The Nordic exports to for instance Germany may also replace German import from for instance France (nuclear power). In this case emissions in non-Nordic countries may hardly change. Full replacement of power from old coal based plants, represents an upper limit for the emission reduction connected to Nordic power export. Figure 14 shows total Nordic emissions from power generation corrected for emission changes in non-Nordic countries.

Figure 14 Nordic CO2 emissions from power generation corrected for emission changes in non-Nordic countries. Change from the Nogas to Gas scenario. Million tons



After correcting for emission changes outside the Nordic area, we see that the main picture is reduced emissions (2005-2008), while there are hardly no emission benefits in 2004 (short-term, low capacity utilization) and 2010 (long-term, high capacity utilization). Again, the year 2009 stands out. Since the change in the net Nordic electricity export was close to zero this year, the correction is negligible and the explanation for the increased emissions is the same as above.

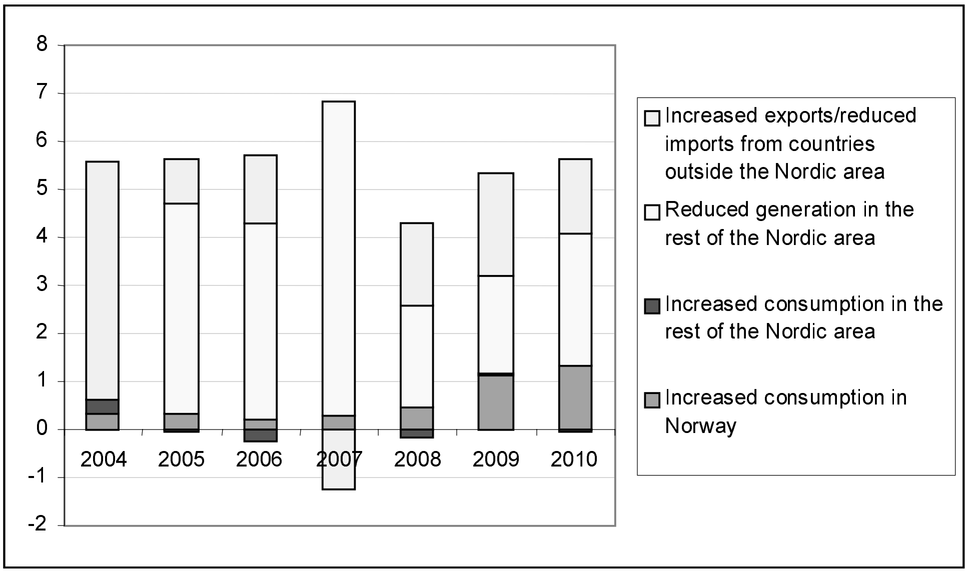
Sensitivity analysis

Future power prices in countries outside the Nordic area are highly uncertain and important for our results. Therefore, we simulated the model with sets of higher and lower non-Nordic electricity prices than used above.

High electricity prices outside the Nordic area

The high price alternatives (Nogas-H and Gas-H) have a base load price in non-Nordic countries of 15 øre/kWh, while medium prices are 18,8 øre and high/peak block have 22,5 øre. Higher prices lead to less import and more exports to non-Nordic countries than in the previous calculations and higher Nordic electricity prices. Power prices move faster towards the long-term equilibrium level. Therefore, the impacts from increased gas power generation in Norway are different in this case. Figure 15 shows how 5.6 TWh new gas power in Norway affect consumption, generation and trade patterns. Figure 15 is of the same type as figure 12 above.

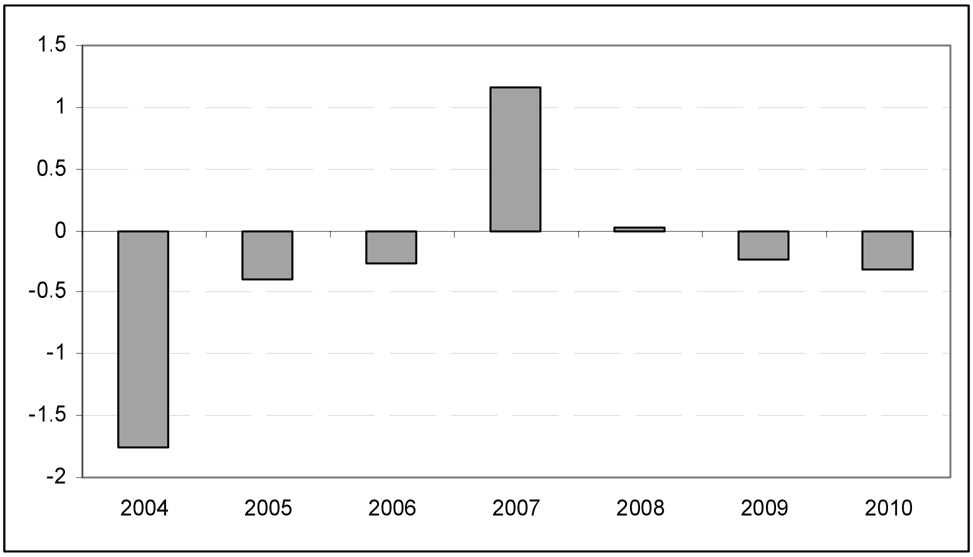
Figure 15 Decomposition of impacts when 5.6 TWh new Norwegian gas power is fed into the Nordic power market in a situation with high non-Nordic prices. TWh



The rest of the Norwegian generation does not change, except for in 2008, when 1.4 TWh hydropower becomes non-profitable to expand when gas power is introduced. The price changes are very moderate and hence the changes in consumption. For some of the years, the capacity addition in Norway leads to higher electricity prices and slightly reduced consumption in Finland since this country now invest less in power generating capacity. Higher consumer prices and lower producer prices at the same time may be consistent, simply because of the electricity trade. During 2004, most of the new gas power is used to lower imports/increase export. Thereafter, replacement of Nordic generation dominates until 2008, when the change in non-Nordic trade and Nordic generation roughly accounts for equal shares of the induced change. In 2007, the situation is somewhat different from the other years. This year, the Norwegian gas power puts a pressure on base and medium block prices in Norway. As a result the Norwegian exports to Sweden during the base and medium block increase. The Norwegian exports to Sweden replace large amounts of imports from Finland. Initially, Finnish base and medium block prices fall and make a lot of capacity unprofitable. At the same time Swedish exports to Finland during high and peak load have become cheaper. That too reduces the capacity needs within Finland. Less capacity and the movement from being a net exporter in the Nogas-H case to being a net importer in the Gas-H scenario leads to higher consumer prices in high and peak block. This movement leads to an increase of power imports from Russia of about 1.2 TWh. The impacts in 2007 are large since there still is unused transmission capacity and generation investments may be very lareg in a single country. After 2007, demand growth, depreciation and higher utilization of transmission capacities leads to more normal and predictable effects.

New gas power in Norway has other impacts when prices are high than when prices are as in the base case, compare figure 15 with figure 12 above. Therefore, the impacts on emissions change as well, see figure 16.

Figure 16 Nordic CO2 emissions from power generation corrected for emission changes in non-Nordic countries. Change from the Nogas-H to Gas-H scenario. Million tons

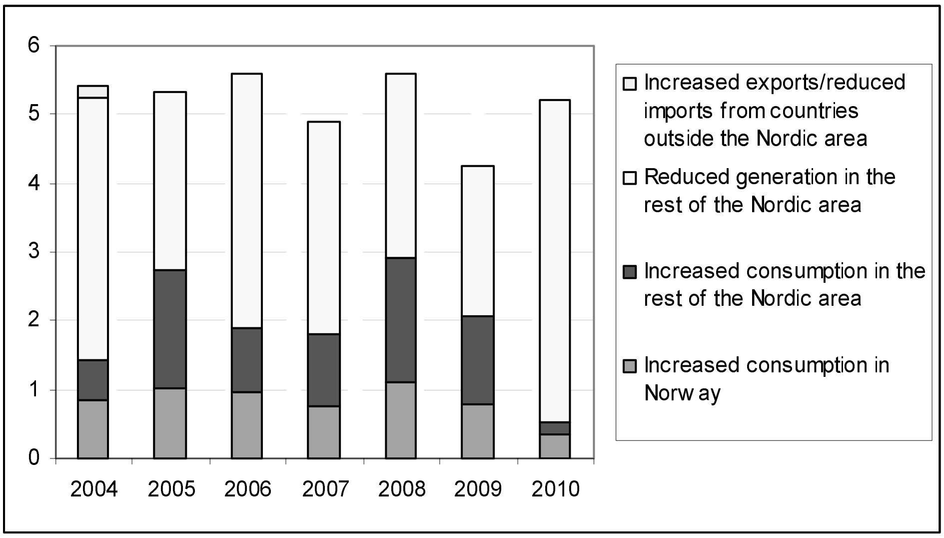


Corrected emissions decrease by near 2 million tons in 2004 since nearly all the Norwegian gas power replaces generation in non-Nordic countries (coal power by assumption). In the following years, emissions do not change much except for in 2007 when corrected emissions increase with 1.2 million tons, see the above discussion of impacts this year. The small changes in emissions in the years 2005-2006 and 2008-2010 is mainly due to the fact that increased Norwegian gas power generation to a large extent replaces gas power generation in other countries, mainly Finland. This substitution does not alter emissions as such.

Low power prices outside the Nordic area

In the alternatives with low prices (Nogas-L and Gas-L), we apply a base block price of 8 øre/kWh, a medium block price of 11 øre/kWh while the high and peak block prices are 14 øre/kWh. These low prices assume large and long-lived overcapacity in non-Nordic countries, in particular Germany. New gas power in Norway is hardly profitable in this case. However, if introduced by political decisions impacts on consumption, generation and trade with non-Nordic countries are as in figure 17.

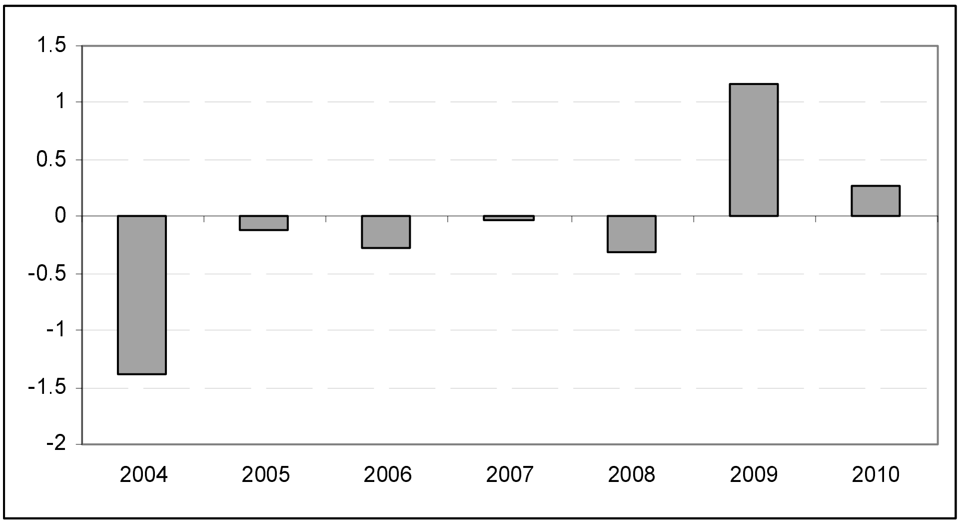
Figure 17 Decomposition of impacts when 5.6 TWh new Norwegian gas power is fed into the Nordic power market in a situation with low non-Nordic prices. TWh



Some of the bars have a lower height than 5.6 TWh because there are some substitution of other Norwegian generation when the gas power generation increases. For instance in 2009 the Norwegian hydropower generation is 1.3 TWh lower in the Gas-L alternative than in the Nogas-L scenario. The transmission capacity between the Nordic area and non-Nordic countries is fully utilized for electricity imports and new gas power in Norway does, except for a very small volume during 2004, not substitute this import. Consequently, prices fall more within the Nordic area in order to get the new power absorbed by the market. The main picture is that Norwegian and Nordic power consumption increases with 1.5-2.5 TWh, while Nordic generation outside Norway falls with about 2-4 TWh per year. The price effects and therefore consumption responses are close to zero in 2010, when the Norwegian gas power replaces Swedish gas power, which then is the marginal generation technology.

While generation in Finland often was marginal in the medium and high price runs discussed in the previous subsections, low non-Nordic prices lead to larger impacts on generation in Sweden and Denmark when Norwegian gas power generation increases. The huge imports from non-Nordic countries keep Nordic capacity utilization and investments low for a longer period than in the previous runs. Therefore, the emission changes may differ, see figure 18.

Figure 18 Nordic CO2 emissions from power generation corrected for emission changes in non-Nordic countries. Change from the Nogas-L to Gas-L scenario. Million tons



In 2004, about 4 TWh Danish coal power with low fuel conversion efficiency is substituted and corrected emissions fall with nearly 1.5 million tons. During the subsequent years 2005-2008, corrected emissions hardly change and the increase in Norway is outweighed by reduced emissions in the other Nordic countries. In 2009, emissions increase when gas power is produced in Norway. This year, the gas power substitutes 1.3 TWh of hydropower in Norway, Nordic electricity consumption increases with 2 TWh and the rest of the gas power volume substitute efficient gas power in Finland. In 2010, when Norwegian gas power replace Swedish gas power, there is only a slight increase of emissions because consumption increases very little.

5 Conclusions

Utilization of Norwegian natural gas resources for electricity generation in Norway has no certain impact on global emissions from electricity production. Transmission capacity utilization is very important for the impacts on emissions. Congested transmission links prevent substitution of, in some cases, less efficient and more polluting generation technologies in neighboring countries. Generation capacity utilization is important as well. If capacity utilization is low, old plants with relatively low efficiency are marginal and the emission benefits may be significant. However, if generation capacity utilization is high and prices equal long-term marginal costs, new and efficient gas power plants may be marginal and emission benefits are negligible. Our calculations include years with increased emissions and years with reduced emissions. Reduced emissions are most frequently observed in the first years after introduction of gas power in Norway when there are some spare transmission and generation capacity. Later in the simulation period, we observe one or two years with increased emissions. During these years, transmission links out of the Nordic area are congested and all the new gas power has to be absorbed in the Nordic power market. Towards 2010, the impacts on emissions are close to zero. At this time, the Norwegian gas power substitutes gas power with comparable fuel conversion efficiency in other Nordic countries. Finally, it is worth noting that we only consider emissions from power production. We do not include emission changes at the demand side. Lower electricity prices may induce some substitution from fossil fuels used for heating purposes towards electricity. On the other hand lower electricity prices may reduce the profitability of combined heat and power generation and thereby induce substitution towards fossil fuels both at the supply and demand side of the market for district heating. However, inclusion of these factors and markets is left for future research.

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Generation costs

Variable generation costs in thermal power plants consist of fuel costs and other variable costs. Fuel prices are assumed constant (real prices) during the simulation period, see table A1. Lindholt (1998) analyze fossil fuel prices. Our price assumptions correspond to a situation between perfect competition and perfect cartel in the petroleum markets.

Table A1 Fuel prices, excl. climate taxes, incl. other taxes, øre/kWh

	Denmark	Finland	Norway	Sweden
Coal*	4.3	4.7	4.7	4.7
Oil*	8.6	8.6	8.6	8.6
Gas, exist. pipel.**	7.0	6.4	5.7	9.9
Gas, Troll-field **	6.5	8.8	5.7	7.4
Gas, Halten-field **		7.6	5.7	6.6
Wood***	13.0	5.6	10.4	10.4
Peat***		7.0		10.4

Sources: * Nordel (1997), ** Bye and Johnsen (1995), *** Olsen and Munksgaard (1996) og Nutek (1994).
Units: 1 kWh = 3.6 MJ = 0.087 Sm^3 natural gas = 3.0 Scuft = 0.085×10^{-3} toe = 3425 Btu.

Denmark is located closer to the world-market and has the lowest coal price. Biofuels (wood and peat) are well established within short transport distances in Finland. Natural gas deliveries through existing pipelines have lowest price in Norway (located close to the North Sea) and in Finland (import of Russian gas). We assume additional gas volumes to be available from the Norwegian gas fields Troll and/or Haltenbanken. Gas from these fields is cheapest in Norway, while transport margins lead to somewhat higher prices in the other countries.

Other variable costs consist of materials and maintenance- and repair costs that are production dependent. In addition, we include start (and stop) costs. Such costs are connected to start and stop of power stations that only run during some part of the day. Start costs may be viewed as a fixed cost. However, we distribute this cost on the generated volume in the period the plant is running when started. Thus, the start costs are mode-specific. If the plant runs in baseload mode there is no start up costs. Consequently, the figures in the first column of table A2 do not include any start-up costs.

Table A2 Variable costs other than fuel costs, øre/kWh

Teknologi*	Base load	Medium load	High load	Peak load
EXT-COAL	4.2	6.7	9.2	19.2
COND-COAL	4.2	6.7	9.2	19.2
EXT-CCGT	1.7	4.2	6.7	16.7
GAS TURBINE				
COND-CCGT	1.7	4.2	6.7	16.7
SS-GAS	2.3	3.6	4.8	9.8
SS-PEAT	1.5	2.8	4.0	9.0
SS-WOOD	1.4	2.7	3.9	8.9

* EXT indicates a central large-scale plan with heat deliveries. SS indicates a decentral small-scale combined heat and power plant, while COND indicates a condensing plant producing electricity only. CCGT is a combined cycle gas turbine power plant.

The estimated start costs are uncertain. We base our estimates on Larsen (1984) and Elsam (1991). Decentral plants is assumed to have lower start costs than large-scale central plants. Gas turbines are designed as a peak load technology and start costs are negligible as is other variable costs.

In the model, new generation capacity is established if power prices on average over a year exceed long run marginal costs for new capacity. Long run marginal costs include capital costs, fuel costs and other variable costs. Capital costs are transformed to a yearly cost assuming a real interest rate of 7 percent and a lifetime of 25 years. The capital cost per kWh depends on the plant's utilization time during the year, see table A3.

Table A3 Fixed costs and fuel conversion efficiency for new thermal power technologies

Technology**	Fuel	Country	Capital cost			Conv. efficiencies*	
			Annualized, 1000 Nkr/MW	5000 h. per year øre/kWh	7500 h. per year øre/kWh	Total	Electricity
EXT-COAL	Coal	D,F,S	700	14.0	9.3	0.91	0.50
COND-COAL	Coal	All	700	14.0	9.3		0.50
EXT-CCGT	N.gas	D,F,S	480	9.6	6.4	0.91	0.60
GASTURB	Oil	All	410	8.2	5.5		0.35
COND-CCGT	N.gas	--"--	480	9.6	6.4		0.60
SS-GAS	N.gas	All	496	9.9	6.6	0.91	0.36
SS-PEAT	Peat	F,S	834	16.7	11.1	0.88	0.30
SS-WOOD	Wood	All	772	15.4	10.3	0.88	0.25

* Fuel efficiency or heat rate. Measured as how many percent of the energy input that is converted to saleable energy, i.e. electricity or electricity and heated water (industrial or district heating purposes).

As table A3 indicates, not all technologies are available in all countries. Denmark, Finland and Sweden have already networks for distribution of heated water (district heating), while such systems are very limited in Norway. We assume exploration and/or transportation costs to prevent peat-fueled power generation in Norway and Denmark. The waterfalls available for development are located in Norway.

The cost estimates represent a complete, new power plant. For some power plants replacement of an existing, old plant may be tah case. Within such projects, costs may be lower if some of the ground investments are already undertaken.

New hydropower projects are available in Norway only. We base the cost estimates on the so-called Master Plan for New Hydropower, see NVE (1997).

Combined heat and power

Table A4 shows our assumptions about heat prices in the Nordic countries.

Table A4 Assumed market prices of heated water. øre/kWh

	Base block	Medium block	High block	Peak block
Winter	2,5	5,0	10,0	10,0
Summer	0,5	2,5	5,0	5,0

The estimated heat price for the high and peak blocks in the winter seasons is 10 øre/kWh. This is a low-end estimate, considerably lower than the heat price used in Olsen and Munksgaard op.cit. In the summer season and in the lower load blocks in the winter seasons, the prices are lower due to lower heat demand.

The potential for cogeneration of heat and power varies. While cogeneration covers 65-75 percent of the district heating production in Denmark and Finland, cogenerated *heat* accounts for only 25 percent in Sweden, see Olsen and Munksgaard op.cit. The fraction of cogenerated *power* differs also highly across the countries. The Swedish district heating systems are today mainly supplied by pure heat plants. Thus, there is a large potential for cogeneration. The potentials for cogenerating power capacity are shown in table A5.

Table A5 Upper limit for the capacity of cogeneration of electricity and heat in the year 2020, MW electricity*

	Denmark	Finland	Norway	Sweden
Large-scale	2800	1700		1700
Small-scale	760	1700	260	1700

* Normalized to coal-fired cogeneration capacity. Cogeneration based on gas has a larger MW_{el} potential.

Fuel supply

Existing and new natural gas pipelines and restrictions on national resource extraction limit the supply of fuels for use in conventional thermal power plants, see table A6.

Table A6 Restrictions on fuel supply for thermal power generation (gross figures = before conversion losses), TWh

	Denmark	Finland	Norway	Sweden
Existing gas pipel.	5.8	29.5	94.4	4.7
Troll gas	Total for all four countries: 94.4			
Halten gas	Total for Fin., Swe. and Nor.: 44.8			
Wood	6.0	20.0	10.0	20.0
Peat		15.0		15.0

Source: Bye and Johnsen (1995).

Depreciation of existing generation capacity

Wind and hydropower has long lifetimes and are not depreciated during our simulation period. Swedish nuclear power is reduced according to political decisions and annual capacity is 64 TWh from 2002. Old power generation equipment is gradually depreciated, and new investments are allowed from 2004. In average, existing thermal capacity has a residual lifetime of about 15 years in 2000. On this basis a 7 percent annual depreciation may sound reasonable. However, we have chosen to depreciate at a slower rate. International experience suggests that thermal power plants often last for a significantly longer time, see Ellerman (1996). Therfore, we start depreciation in 2002-2004 at an annual rate of 3-4 percent.

In Norway, we limit hydropower developments until 2010 to 8 TWh, Based on information available in January/February 2000, Norwegian hydropower generation is assumed to be 116 TWh in 2000. However, when this is written it is clear that water inflow and snowfalls during winter 2000 has been much richer than initially assumed. The figures reported for 2000 should be viewed in this light.

Transmission costs

Table A7 lists the costs of electric transmission among the Nordic countries.

Table A7 Transmission costs and annualized investment costs for new connections, øre/kWh and 1000 Nkr/MW

	Operating cost	Annualized investment cost
	øre/kWh	1000 Nkr/MW
Denmark - Norway	0.7	170
Denmark - Sweden	0.5	120
Finland - Norway	1.0	200
Finland - Sweden	0.4	110
Norway - Sweden	0.3	110

Source: Nordel (1997) and Vognild (1993).