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Simulations of the Capacity balance in Norway and Sweden

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RESULT (summary)

A model for the capacity balance in Norway and Sweden has been developed, and the capacity balance for all peak load hours for stadium 2005 is simulated. The following methodology has been used: Forecasts for the hourly general demand in 2005 are basically established by combining historical registrations of hourly demand with annual demand for the historical and the forecasted year. Constant demand profiles are assumed for other sectors. Each year with hourly registrations gives a unique load demand profile that can be used to study the effect of the temperature profile of that year. For years without hourly registrations demand profiles are estimated on basis of the demand profile in 2001 and the difference in daily temperatures in 2001 and the historical year. The supply side of the model accounts for hourly production and transmission capacities, availability of capacities in different periods, annual energy capacities, reserve requirements, production costs etc. In the model solution, the socio-economic surplus in the Norwegian/Swedish region is maximized.

In the Baseline scenario, which is slightly pessimistic, there is some capacity deficit and corresponding load shedding for Norway and more for Sweden. The average load shedding is considerably larger for historical load profiles between 1972 and 1989 than for newer years since the climate has been milder. For Norway, almost all load shedding occurs in weeks 1, 4, 6 and 7. While Norway is a net importer from Sweden on an annual basis, Sweden needs and obtains electricity from Norway during peak load periods in the Nordic region.

The scenario analysis shows that the load shedding is eliminated for the period after 1990 if the full export capacity from Denmark can be utilized, if the availability of hydropower is increased by 5%, if 1000 MW reserves are issued from consumers, if a 1200 MW cable is built e.g. to England, or if or Norwegian boilers are shut down during peak price periods (zero load shedding only for Norway). The trade between Norway and Sweden tends to give approximately the same effect of changed assumptions on the capacity balance in both countries. For load demand profiles of earlier years, the same scenarios gives considerable improvements for the capacity balance even though there is some load shedding.

KEYWORDS		
SELECTED BY AUTHOR(S)	Capacity balance in the Nordic region	Load shedding
	Capacity shortage	Electricity market forecasts

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1 INTRODUCTION

This report documents the results from sub-project "Capacity Balance Simulations" under the project "Competence Building – Capacity Shortage", financed by the Research Council of Norway and the Norwegian Electricity Industry Association (EBL), Statkraft, Statnett, Norske Skog, Nord Pool and Norsk Hydro. The objective of the project is to increase knowledge about central approaches aimed at solving the peaking capacity problem in restructured power systems. Specifically, the project will assess the following fields:

- Market based solutions to provide reserve capacity
- Consequences of specific reserve requirements
- Intensity, duration and uncertainty of shortage incidents
- Innovative solutions

The project has a Nordic perspective with relation to the applicability of proposed solutions, but an international perspective with respect to solutions, methods and cooperation.

To assess the intensity, duration and uncertainty of potential capacity shortage incidents, a simulation model was developed for the Norwegian/Swedish power market. The focus of the model is on the demand side rather than the generation side. The rationale behind this is that during extreme demand situations, generation in the Nordic power market is more predictable than demand. Alternatively, we can say that the uncertainty and variability of extreme peak demand is a more important factor in the analysis of extreme demand situations than the availability of generation capacity when the availability of the latter is high and predictable.

Recently, from the end of 2002 until presently, the energy situation has had more attention than the potential shortage of peaking capacity. This is naturally a result of the extremely dry autumn of 2002, resulting in very low reservoir levels and unusually high prices. This had an impact on total demand in Norway, with sunk from approximately 124 TWh in 2001 to 116 TWh in 2003, and this probably has at least a proportional effect on peak demand. It seems presently probable that a certain share of domestic heating demand has shifted to other fuels, and as a result demand will become less sensitive for low temperatures.

In the longer run, this will probably not be a lasting effect, unless we should experience frequent severely dry periods. Consequently, it is appropriate to estimate under what circumstances available capacity in the combined Norwegian/Swedish system will be insufficient to cover demand.

1.1 BACKGROUND

In a free electricity market it should in principle not be necessary to worry about the availability of peaking capacity. If there is a deficit, prices increase. This reduces demand and gives a signal to the supply side to invest in new capacity. However, there are good reasons why this mechanism does not guarantee an optimal solution in the electricity market:

- Electricity cannot be stored economically. This means that there has to be a continuous minute-to-minute balance between demand and supply.
- There are very high requirements to reliability. The reason for this is the high costs to consumers of power interruptions. Consumers' preferences for electricity can be viewed as "asymmetric": the cost of an interruption is much higher than the general willingness to pay.
- The power system is one large interconnected system, where problems under high-load conditions can result in new problems other places. The final consequence of a component outage somewhere in the network can be system collapse, resulting in long and extended interruptions of demand and huge costs, cf. recent cases in North-America, England, Sweden and Italy.
- Traditional tariff systems completely protected consumers from short-term variations of the spot-market price. Although this is slowly changing, total short-term demand response is still very limited.

As a result, the availability of peaking capacity is a potential (and in some places already real) problem in restructured electricity markets. Because most market reforms started in a surplus situation, this was not evident initially, but the problem is presently acknowledged as one of the major challenges of restructured power systems.

The characteristic property of peaking power is that it is needed only a few hours annually, especially when demand is strongly related to ambient temperature, and moreover that the need for it is uncertain. Partly because of this, it is unclear if the existing market design is capable to provide sufficient peaking capacity. Failure to solve the peaking power problem will sooner or later result in involuntary load-shedding. If a satisfactory solution to this problem is not found, the whole restructuring process may be at stake.

1.2 SCOPE

In the current project estimates are made of the probability that peak demand will exceed the production capacity for Norway and Sweden. In the analysis, we have used a model for capacity balance developed in a PhD thesis [1]. Many uncertain factors are important for the answer to this problem, among others:

- the possible import to Norway and Sweden from other countries during peak load periods
- annual demand in various sectors
- investments or closure of existing capacity
- demand elasticity
- availability of hydropower
- temperatures

All these uncertainties (except the uncertainty in annual demand) are dealt with in various scenarios in this report. Since a large share of the demand is sensitive to temperatures, and temperatures are very uncertain compared to most of the other uncertain factors mentioned, this is the most important short run (e.g. within a month) uncertainty for the capacity balance. Thus, temperatures have been given more attention that the other uncertain factors. For each scenario of e.g. import possibilities, production capacities etc, we have a systematic analysis of how the uncertainties with respect to temperatures affect that scenario.

The model simulates all peak-load (winter-day) hours for a set of observed temperature profiles over the year. The remaining hours are handled in aggregate, but they are included in the model so that an annual energy balance can be calculated. For each simulated hour the model calculates the capacity balance: production for various technologies, consumption in various sectors, trade from specific countries and a potential capacity deficit. If we assume that the temperature profiles are drawn from a representative pool of historical years, we can calculate the probability distribution e.g. for peak loads, involuntary load shedding, maximal electricity prices etc. However, as already mentioned, the model focus is on the demand side, and therefore, price calculations are not given too much weight.

1.3 STRUCTURE OF REPORT

Section 2 describes the general approach used in the project, the mathematical model and data preparations. Findings from scenario analysis are provided in Section 3. At first, historical peak load periods are reproduced. Secondly, a base-year scenario for 2005 is calculated, and finally we study the effects of changing various assumptions with respect to demand and supply. Section 4 concludes.

2 METHOD

2.1 General approach

While it takes a long time to increase generation capacity in the electrical system, the peak load changes from day to day depending especially on ambient temperatures. Thus, the handling of temperature influence on demand is the core of the model. It is also the most refined part of the model. The model is an alternative to the calculation of peak demand and comparison with available generation and import capacity, and offers several advantages:

- Instead of giving a single peak demand point, a complete duration curve for peak demand is calculated
- Because many temperature scenarios are analyzed, it is possible to say something about the probability distribution of peak load

The HOMAX model (HOurly MAX model), is a single-year model for demand and supply of electricity. It is a linear optimization model programmed in AMPL and solved in C-PLEX. In the current project, the HOMAX model was extended to a multi-area model. Presently, data for Norway and Sweden has been implemented, but there are no principal problems with extending the model to more areas. The model accounts for trade with other regions at exogenous prices that vary over the season. The model maximizes the aggregate socio-economic surplus in Norway and Sweden. This can, however, be interpreted as a market solution since the first welfare theorem of economics states that a decentralized economy is efficient unless there are externalities [2]. The model accounts for the utility of power consumption, production costs of various technologies, income and expenses from trade with non-model countries and load shedding costs.

There are a number of constraints on the supply side in the model, e.g. maximum generation capacity for individual hours and for the aggregate over the year for hydropower. Domestic demand can be sensitive to prices. The model finds the optimal balance for each period within the year. There may, however, be load shedding if demand in a particular hour exceeds the available capacity or if annual demand exceeds maximum supply when constraints for annual hydropower production is taken into account.

Based on forecasts for annual demand and relative demand in different hours in specific years in the past, a set of load demand profiles is established for the forecasted year. We assume that variations in the relative consumption in a particular hour between different years are caused entirely by differences in the temperature profiles for these two years. Thus, a set of load demand profiles corresponding to historical temperature profiles is established. Each temperature profile's influence on annual consumption is also calculated. The model is solved for a future year for each historical temperature profile. The *baseline scenario* is in fact a set of scenarios covering different historical temperature profiles. In *sensitivity analyses*, we change other uncertain factors for demand and supply, and for each of these scenarios we loop over all temperature profiles.

The mathematical model is shown in Appendix A.

2.2 TIME RESOLUTION

Extreme peak demand occurs in the winter season, on working days during daytime. In the model, these hours are represented individually, while nights, weekends and off-peak seasons do not need a detailed representation. In total there are 2210 periods in the model, compared to 8760 hours in a 365 days year.

2.3 DEMAND DATA

The final goal in our demand data preparations is to establish demand profiles over the year. To do this, we combine relative demand in past years with forecasts for annual power consumption for a future year, and then we derive how the hourly demand in the future year would be if temperatures in past years were reproduced. We also take into account how temperatures for historical years affected the annual consumption compared to a year with normal temperatures, which typically are used in forecasts.

Since we establish several demand profiles from historical years, we also get several hourly forecasts for the simulated year, and each forecast corresponds to a particular historical temperature-profile. Since only parts of the demand is sensitive to temperatures and the relative demand in different sectors change over time, it is also necessary to divide the demand into various sectors.

2.3.1 Years with hourly demand registrations

For the years 1989-2002 for Norway and 1996-2002 for Sweden, hourly gross use of electricity are available from [3]. For our purpose we do, however, need information about hourly consumption of electricity in different sectors since not all sectors are sensitive to temperatures. We make the following assumptions:

(a) Demand from the energy-intensive industry and boilers is constant throughout the year. Annual demand is taken from official statistics.
(b) Pumping demand is constant during the summer period, week 19-44. Annual demand is taken from official statistics.
(c) General demand is registered total demand minus estimated demand for energy-intensive industry and pumping.

These assumptions can also be written mathematically. Let J be the set of sectors where $j \in J = \{ind, boil, pump, gen\}$ and T be the set of hours in a year in where $t \in T = \{1, \ldots, t_{year}\}$. In a year with 365 days, t_{year} *is* 8736. Let T^{summer} be the a subset of T for week 19-44 and let t_{summer} be the number of hours during the summer. Let $P_{j,t}$ be hourly power demand in sector j in hour t, while P_t is total demand. Moreover, According to assumption (a), we know that

$$P_{j,t} = \frac{W_j}{t_{year}} \quad \text{for} \quad \forall t, j \in \{ind, boil\} \tag{1}$$

where W_j, $j \in \{ind, boil\}$ is annual consumption. Data for Norwegian industry are taken from [4] for years before 2002, from [5] for 2002, from [6] for boilers (numbers for occasional power are used), while industry in Sweden is taken from [7]. For Norway, numbers for industry is "power intensive industry", while paper, chemical, steel and metal industry is used for Sweden. For boilers and pumping Swedish numbers are set to zero. According to assumption (b) we know that

$$P_{pump,t} = \begin{cases} \dfrac{W_{pump}}{t_{summer}} & \forall t \in T_{summer} \\ 0 & \forall t \notin T_{summer} \end{cases} \qquad (2)$$

where W_{pump} is taken from [6] for Norway. From (c) we know that

$$P_{gen,t} = P_t - P_{ind,t} - P_{pump,t} \qquad (3)$$

Now we can substitute (1) and (2) into (3), and this gives

$$P_{gen,t} = \begin{cases} P_t - \dfrac{W_{ind} + W_{boil}}{t_{year}} - \dfrac{W_{pump}}{t_{summer}} & \forall t \in T_{summer} \\ P_t - \dfrac{W_{ind} + W_{boil}}{t_{year}} & \forall t \notin T_{summer} \end{cases} \qquad (4)$$

Thus, we have established data for $P_{j,t}$ $\forall j,t$. The relative demand profile for general demand, the *per unit demand*, is defined by

$$pu_t \equiv \frac{P_{gen,t}}{\sum_{t \in T'} P_{gen,t}} \qquad (5)$$

where T' is the set of all hours in a full 52-week year staring by the first hour in week 1. These per unit demand profiles are calculated for each year according to (1) – (4) for years where hourly demand is available. This approach implicitly takes into account the temperature influence on relative consumption for different years. In addition we need information about how the temperatures in various years affect annual general demand compared to normal temperatures. This information is provided by [8] for Norway after 1994 and calculated for 1989-1994. For Sweden information is available from [9] for Sweden. In cases where numbers are given net of loss, we have assumed 10% loss for general demand, 3% loss in industrial consumption and 7% loss in pumping.

The final output from these data preparations is

- relative values of general demand for each hour (period), pu_t
- temperature influence on annual general demand
- 52-week sum for consumption in general demand (temperature corrected), industry and boilers

2.3.2 Years without hourly demand registrations

For years before 1989 for Norway and before 1996 for Sweden, hourly demand registrations are not available. However, if the relation between temperature and demand is known, demand from years with hourly registrations can be transformed to years without such registrations. NVE uses factors describing such relations, based on a method developed in [10]. These factors are given on a regional basis in GWh/°C/week. These factors are used to apply temperature correction of demand, i.e. to find out what demand would have been with normal temperatures:

$$W_N(w) = W_M(w) + (\tau_M(w) - \tau_N(w)) \cdot c_E(w) \tag{6}$$

where w is the week number, W_N and W_M normal and measured energy consumption, τ_N and τ_M normal and measured temperature and c_E the temperature correction factor in GWh/°C/week. This corresponds to an average hourly correction factor c_P (MW/°C) by dividing c_E by 0.168. We make the additional assumption that this correction factor in MW/°C can be used on a daily basis, using average *daily* temperatures. The argument for this assumption is that the demand for heating is relatively independent of the time of day. However, there are some complications, which are discussed in the next section

With a base year with registered hourly demand, the demand profile can then be transferred to another year with given temperatures:

$$P_{gen,t} = P_{bas,t} + \left(\tau_t - \tau_{bas,t}\right) \cdot c_P(w) - P_{ind,t} - P_{boil,t} - P_{pump,t} \tag{7}$$

where $P_{bas,t}$ is total demand in hour t the base year, and τ_t and $\tau_{bas,t}$ mean daily temperature on the corresponding day in the calculated and base year respectively.

2.3.3 Non-linearity of temperature correction

It is well known that the assumed linear relation between temperature and demand is unrealistic for very low temperatures. The physical explanation is that there is a saturation effect – when it becomes very cold, consumers do not have enough heating capacity and compensate by using other fuels or (involuntary) reducing indoor temperature. The linear model of (7) thus overestimates real temperature dependency for extreme temperatures.

The program used by NVE takes this into account by limiting the correction of demand a certain maximum deviation from normal temperatures. The maximum deviation is taken as a certain number of times the standard deviation of the temperature in the actual week. The standard deviation is typically calculated by taking the average weekly temperature for that week in the last six years, and applying some (undocumented) smoothing. In their calculations, NVE probably use a maximum temperature deviation of two standard deviations.

It is not straightforward to decide how to use this only partly documented procedure to the calculation of daily demand based on daily temperatures. There are a number of factors to take into consideration, e.g.:

- average daily temperatures vary more than average weekly temperatures
- there is a certain delay in demand when temperatures fall quickly – when a sequence of several cold days occurs, demand will normally peak after two or three days
- six years is a short period to calculate the standard deviation of demand

These issues should be explored further in a future project. In the present analyses we have chosen to limit the correction of demand to 2.0 times the standard deviation of the weekly temperature. Without this limitation, calculated demand clearly was too high for very low temperatures.

2.3.4 Annual forecasts and growth rates

We use annual forecasts to establish growth factors for various sectors from a historical year to an arbitrary future year, preferably between the historical year and the year with an annual forecast. Let the growth rate of demand in sector *j* be r_j, and suppose that we use numbers from 2001 and a forecast for 2005 to calculate growth rates, we get:

$$r_j = \left(\frac{W_j^{2005}}{W_j^{2001}} \right)^{\frac{1}{2005-2001}} - 1 \qquad (8)$$

where W_j^{nnnn} is a forecast of annual consumption in sector *j* in year *nnnn* with normal temperatures. For Norway growth rates are calculated on the basis of numbers for 1999 and 2005 in [11], while numbers for Sweden (2001 and 2004) are taken from [12]. For Sweden we use numbers for "industri" and "bostäder, service m.m." to represent the growth rate of our categories "industry" and "general demand".

2.4 SUPPLY SIDE PARAMETERS

The following power production technologies are accounted for in the model for Norway and Sweden: hydropower, thermal (condensing power plus gas turbines etc), CHP (district heating plus industry), wind and nuclear. The three first technologies are "endogenous", so that the supply is determined by optimization, while the production is exogenous for the last two technologies.

Maximum production capacity is approximately 27650 MW for Norway, while the wind power capacity was about 17 MW in by the start of 2002 [13]. For Sweden, capacity numbers are taken from [12], except from thermal and CHP that is taken from [14].

Availability for Norwegian hydropower is assumed to be 0.89 during the winter, 0.80 during late winter.. For wind-power in Norway, relative availability is calculated on basis of relative production from [5], and these availability numbers are scaled so that they are consistent with the

annual relative magnitude between production capacity and annual production [13]. For Swedish hydropower, the availability for winter and late winter is calculated as the fraction between the assumed available capacity for hydropower during peak loads (in MW) in [15], and the hydropower capacity [12].
The available capacity for thermal production is taken from [15], but we add 1000 MW since the numbers in [15] are net of these reserves. In our model, the reserves are divided between technologies based on optimality. The total capacity numbers are taken from [12], which also must be increased by 1000 MW. The availability for thermal production during peak load is calculated as the fraction between the available capacity and the total capacity, and this gives 0.54. This number is also used for CHP, but the availability is reduced to 0.27 during the summer. Availability for Swedish nuclear and wind-power is set as average production in winter, late winter and summer in 1997-2001 respectively [16] as a fraction of the average capacity in the same years [12].

Import capacities are taken from [17]. For Norway we assume that 50 % of the physical import capacity from Denmark is available for import during (winter, day) and (late-winter, day) to take into account that not enough generation capacity may be available in Denmark to sustain full export to Norway and Sweden. For Sweden we base our assumptions on [18], where maximum import during peak loads are discussed. We assume that the maximum import capacity for Sweden during daytime in winter and late-winter is 1000 MW from Denmark, 200 MW from Finland and 300 MW from others (Germany+Poland). The import from Norway is determined by the model and restricted by import capacities in [17]. The import price from Denmark is assumed to be 150 NOK/MWh except in winter day and late-winter day where the price is 350 and 200 respectively. The import price from others is assumed to be 250 NOK/MWh except during winter-day, where the price is set to 350.

2.5 LOAD SHEDDING

Load shedding may occur in the model for two reasons:

- A shortage of available capacity in the combined Norwegian-Swedish system, including import capacity to third countries.
- A shortage of available annual energy.

The present analysis is focused on the first reason, but energy shortage can occur in dry year hydro scenarios. A shortage of available capacity occurs when all generation and import capacity is utilized, and demand is reduced to a level where there is no more price elasticity. Shedding costs are set to approximately 2000 NOK/MWh. The exact level is not important in the present analysis, the main point is that these costs are very much higher than all other alternatives.

Shedding costs are given in three levels of 2000, 2100 and 2200 NOK/MWh for 3, 6 and 100 % shedding respectively. This differentiation has two effects:

- A certain spreading of shedding between Norway and Sweden. A loss of 7 % is used on the interconnection. This means that the price difference[1] between the countries cannot exceed 7 %, which in turn means that shedding level 1 in the exporting country is taken in use before the third level in the importing country is used.
- In the case of energy shortage, rationing is divided over longer periods

Table I shows the corresponding prices in the importing and exporting country if there is load shedding in either of them. If the load shedding in the exporting country is *caused* by extreme prices in the importing country, then the price in the importing country must be at least NOK 2150. For the 31 annual peak load hours for Sweden, one for each load demand curve for 2005, there are 9 occurrences of prices equal to 2150 or 2200. During these hours there is load shedding in both Norway and Sweden, and in 3 cases the Norwegian export to Sweden is larger than the Norwegian load shedding.

Table I: Prices in the importing and exporting country respectively for different shedding levels.

Importing country		Exporting country	
Domestic price (p_{imp})	Shedding level	Domestic price (p_{exp})	Shedding level
p_{imp}	-	$0.93*p_{imp}$	-
2000	1	1860	- (*)
2100	2	1953	- (*)
2150	2	2000	1
2200	3	2046	1

(*) One extra MW exported would generate 1 MW domestic load shedding.

Shedding costs are also slightly differentiated between day, night and weekend, the daytime having the highest value. This implies that rationing due to energy shortage is done during weekends and nights if possible.

[1] Price calculation in the model is very simple and just represents the variable cost of the marginal technology. Norway and Sweden can in market terms be viewed as two price areas, but there will be a price difference corresponding to the losses on the interconnection.

3 SCENARIOS FOR 2005

3.1 BASELINE SCENARIO

In the first simulation a baseline scenario for the assumptions described in Chapter 2 is established. Afterwards the effects of changing some important assumptions are analyzed.

The baseline scenario is somewhat pessimistic since it is assumed all demand, including electrical boilers and other types of occasional power, are insensitive to prices. Appendix B provides detailed input data. The model is solved for the year 2005 for each load demand curve in the period 1972-2002. The differences between model solutions for different load demand curves illustrate the span of uncertainty for the energy- and capacity-balance due to the uncertainty in temperatures in 2005. Table II shows the mean energy balance for the 31 load demand curves and the peak load hour capacity balance for the highest. The peak load balance for load demand curves in the period where we have hourly registrations of consumption is also provided (from 1989 for Norway and from 1996 for Sweden), because the input data for this period is considered more reliable. The annual balance shows that the average annual load shedding is 6 GWh for Norway. The division of the annual load shedding over different weeks is shown in Figure 1.

3.1.1 Comparing main figures with Nordel's forecasts

If we assume that the temperature profile in 2005 will be drawn from the set of temperature profiles from 1972-2002, and that each profile has equal probability, then the mean energy balance is the expected energy balance. Thus, we can compare our mean energy balance numbers with other forecasts for "normal" years. In the following we will compare some of the main figures in our simulated energy and capacity balance with historical numbers and Nordel's forecasts for 2005.

The expected total demand in 2005 in our model is 127 TWh for Norway and 149 TWh for Sweden. On the supply side, the *annual* energy is fixed for some technologies. In the model, the largest degree of freedom is for thermal production in Sweden and for import/export.

Thermal production, which only covers gas turbines and condensing power in our model, has zero production in our model. The reason for this is that this is the most expensive technology. Thus, the whole thermal capacity stands as reserves in our baseline simulation. The CHP production, which exists of thermal production in the district heating systems and in industry, is sensitive to prices in the model. The mean annual production for CHP in Sweden is 12,1 TWh in our simulations. By comparison, Sweden produced 11,2 TWh thermal power in 2002 [19].

The expected net import is 8,2 TWh for Norway and 6,3 TWh for Sweden. Nordel's numbers are 10 TWh for Norway and 6 TWh for Sweden. Thus, the trade balances are roughly in accordance with Nordel's forecasts.

Table II: Mean annual balance and balance in the peak load hour for 2005.

	Mean annual balance (GWh)		Peak load hour balance 1972-2002 (MW)		Peak load hour balance Norway: 1989-2002 Sweden: 1996-2002	
	Norway	Sweden	Norway	Sweden	Norway	Sweden
demand						
general	87025	111469	20608	24687	19755	23509
industry	34291	37606	3925	4305	3925	4305
boilers	5490		628		628	0
pumping	877					0
TOTAL	127683	149075	25161	28992	24309	27813
supply						
hydro	119472	65972	23102	13807	23102	13807
nuclear		64123		8870		8870
CHP		12147		1862		1862
thermal						
wind	49	504	7	70	7	70
net import	8155	6296	600	2112	600	2289
shedding	6	31	1453	2271	600	915
TOTAL	127683	149075	25161	28992	24309	27813
import						
Norway		1445		612		789
Sweden	3201					
Others	7084	17270	600	1500	600	1500
export						
Norway		3442				
Sweden	1554					
Others	575	8975				

Since we have used load demand curves for the period 1972-2002, the peak load balance in Table II can be interpreted as the peak load for a 30-year winter. The peak load is 25161 MW for Norway and 28992 MW for Sweden. Nordel's numbers for a 10-years winter in are 23880 MW for Norway and 28800 MW for Sweden in [17], and 24100 MW for Norway and 28100 MW for Sweden in [20]. Thus, the hourly peak load in our analysis is 1061 MW and 192 MW higher than the highest Nordel forecasts for a 10-year winter for Norway and Sweden respectively. However, in [25] it is pointed out that expected demand in a 30-year winter is 400 MW higher than in a 10-year winter in Norway and 1500 MW higher in Sweden.

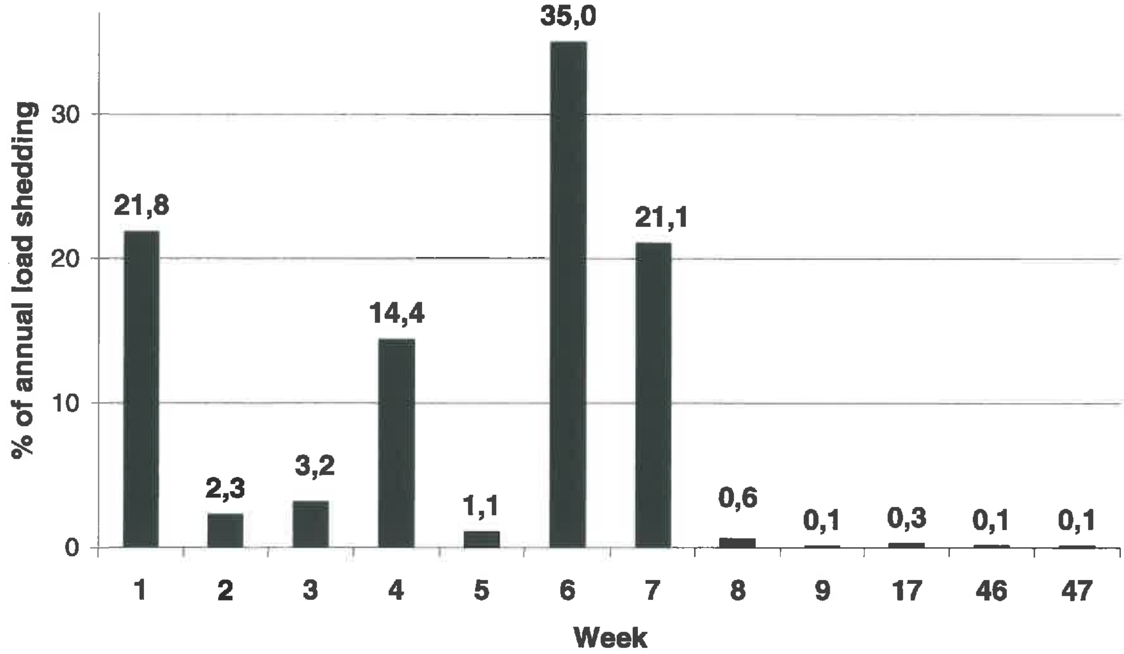

Figure 1: The average distribution of load shedding over the year for Norway for 2005 with load demand curves 1972-2002.

The climatic conditions of the late 70's and the 80's were colder than the climate of the 90's. As a consequence, we do not have hourly registrations of demand for coldest period. The methodology used for calculating load profiles for years where hourly registrations are missing, have made it possible for us to establish load demand curves also for the colder 80's. This may explain why our peak load estimates are somewhat above Nordel's peak load forecasts. We do, however, believe that the temperature correction methodology we have used can be improved since it is relatively sensitive to the selection of basis-year (a year with hourly registrations) at current. For years with hourly registrations, we do not have to use temperature correction (1989 and later for Norway, 1996 and later for Sweden). The peak load for that period is 24309 for Norway and 27813 for Sweden. For Norway, this is 209 MW above the highest of Nordel's estimates, and for Sweden it is 287 MW below the lowest of Nordel's estimates.

Another possible explanation to the difference between our estimates and Nordel's estimates can be that the demand is insensitive to prices in our model. In reality, there is probably a tendency in the direction of increased price elasticity even in the short term. Especially boilers and industry are assumed inelastic in our baseline scenario. In Norway, boilers use 628 MW in the peak load hour in our simulations, cf. Table II. This is over half the difference between our peak load estimate and Nordel's peak load estimate. Moreover, our 10-years peak (average of the 3 largest maximum peak loads of the 31 load demand curves), is about 100 MW less than the largest peak. If we assume boilers are shut down during the peak load, the difference between our estimate for a 10-years winter and Nordel's estimate is approximately 300 MW for Norway.

As a conclusion, the peak loads estimates used in this study are compatible with Nordel estimates, allowing for uncertainties and different assumptions.

3.1.2 Peak load capacity balance for Norway and Sweden

Figure 2 shows the peak loads in Norway and Sweden and load demand curves 1972-2002 for 2005. On average, the Swedish peak load is approximately 4000 MW larger than the Norwegian peak load. Moreover, there is a clear positive correlation between the peak load estimates in Norway and Sweden. This is of some importance since the possible import from the other country during the peak load hour is reduced in practice if both countries have a tight capacity balance.

If we look at the loads above 28000 MW for Sweden and above 24000 MW for Norway, it is evident that the climatic conditions of the late 70's and the 80's gave higher peak loads than the climate of the 90's and up to today. As a result, we can expect significant load shedding in the peak loads if we believe the climate from the 80's comes back, while the situation is far more comfortable if we think the climate from the 90's continues, cf. Figure 3, e.g. due to global warming.

The load shedding in the peak load hour is larger for Sweden than for Norway for all temperature-years except 1984 and 2001, and approximately twice as large on average. The largest load shedding for Sweden is for 1978 (2603 MW). For Norway the largest load shedding is for 1984 (1453 MW).

If we look at all load demand curves, there is load shedding for 2005 in 19 of 31 years for Sweden, and in 14 of 31 years for Norway. One interpretation of this is that it the probability for load shedding in the peak load hour is 61% for Sweden and 45% for Norway. However, if we believe that the climate from 1990 onwards continues, the corresponding probabilities are 38% and 15%. Thus, the situation is far more comfortable, especially in Norway, if we believe that the mild climate continues. Still, there will not be enough capacity for the peak load in 1 out of 7 years in this case either. It can of course be argued that there should be controlled load shedding in some years if the socio-economic efficient capacity is installed since there is a trade-off between the costs of installing additional capacity and the expected load shedding costs.

It has been assumed that reserves are maintained at their required levels, i.e. that load is shed without using available fast reserves to avoid or reduce load shedding. In practice the TSOs will use a certain share of these reserves to avoid load shedding at the cost of reduces system security. Thus the load shedding estimates in this analysis are too high, but on the other hand load shedding clearly indicates a severe situation with respect to system security.

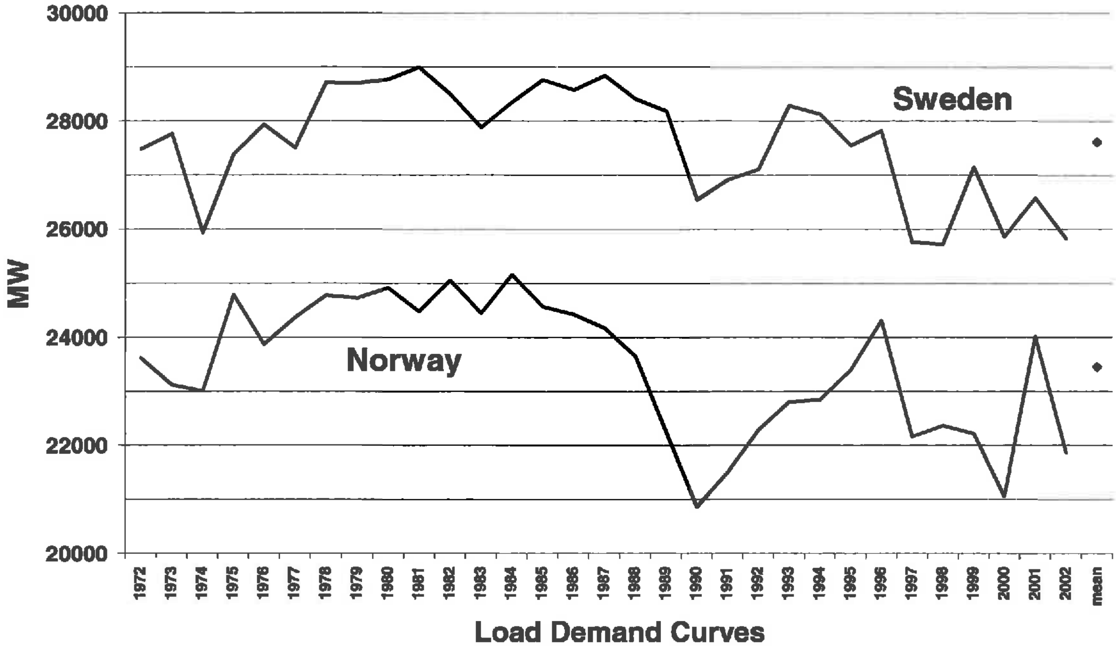

Figure 2: Peak loads forecasts for Norway and Sweden in 2005 for the baseline scenario.

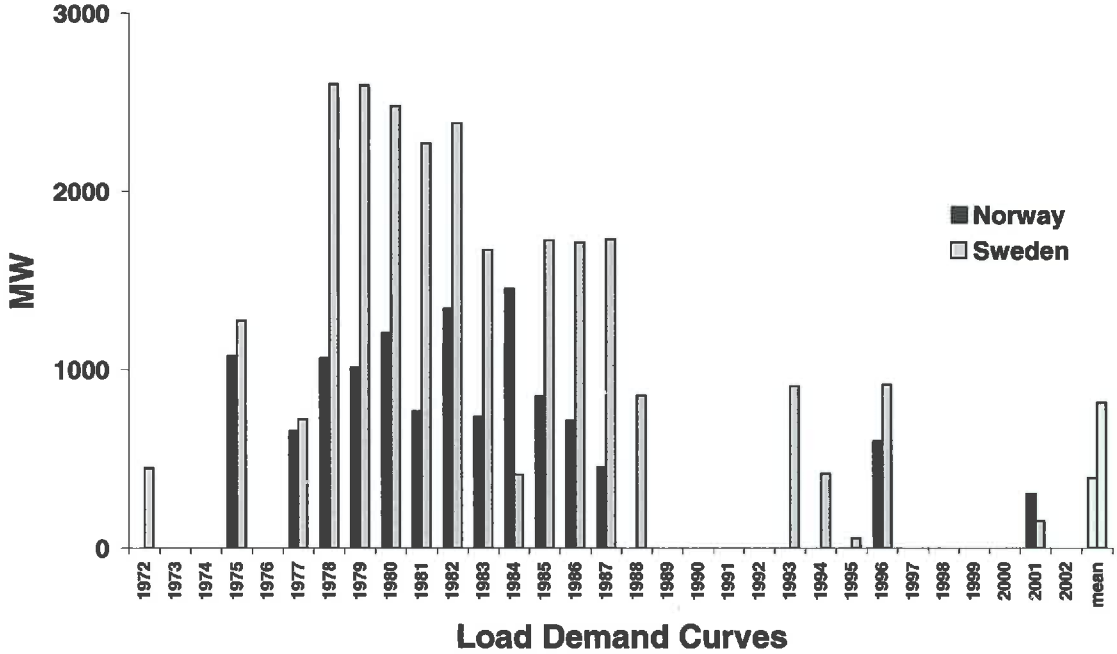

Figure 3: Load shedding in peak load hour for Norway and Sweden in 2005 for the baseline scenario.

The number of hours with annual load shedding is shown in Figure 4. Again we can see that the situation is worse for load demand curves of the 80's than for the 90's, and worse for Sweden than for Norway. The maximum for Sweden for 1985 (138 GWh), while the maximum for Norway is for 1982 and 1984 (36 GWh). If 1 extra MW of capacity had been installed in Norway, this would, on average, reduce the average annual load shedding by approximately 13 MWh since the average number of hours with load shedding is 13 hours, cf. Figure 5. If we assume a shedding cost of 20 000 NOK/MWh the value of reduced load shedding is 260 000 NOK. Thus, if the annualized costs of installing and using 1 MW capacity during capacity shortage hours is less than 260 0000 NOK, this analysis suggest that this is a profitable and socio-economic efficient project. The income from peak load hour production is, however, very sensitive to changed assumptions. If the mild climate of the 10 most recent years continues, the corresponding number is 12 000 NOK. On the other hand, the average number of hours with load shedding in Sweden is more than twice as large as in Norway. The value of increased production in Norway will be at least $20000 \cdot (1-0.07) = 18600$ NOK in these hours unless all the transmission capacity is used, and that is not the typical case, cf. Figure 6 that shows the Swedish import during the Swedish peak load hour. Figure 7 shows the Norwegian import during the Norwegian peak load hour.

In Figure 5 we can again see some of the main findings: The number of hours with load shedding is larger for Sweden than for Norway, and there are more hours with load shedding during the late 70's and the 80's than in the 90's. Thus, there is a strong positive correlation between the number of hours with load shedding in Norway and Sweden.

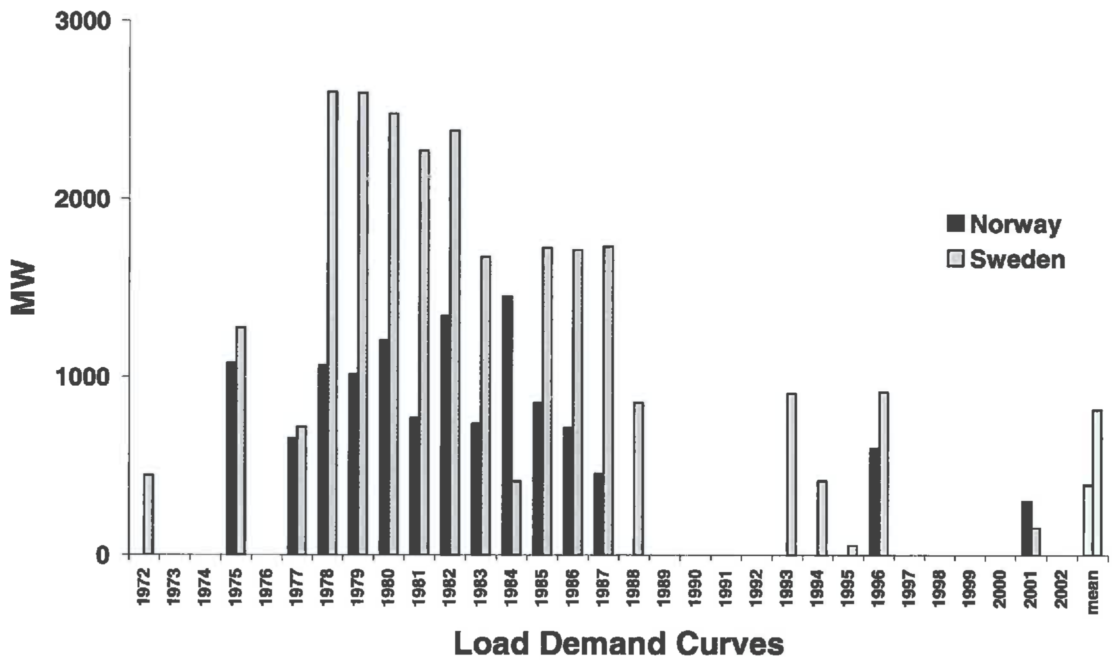

Figure 4: Annual load shedding in Norway and Sweden in 2005.

The maximum number of hours with load shedding in 2005 is for the 1986 load demand curve for Sweden (133 hours), and for the 1984 load demand curve for Norway (58 hours). After the 80's the largest number of hours with load shedding is for 1996: 30 hours in Sweden and 4 hours in Norway.

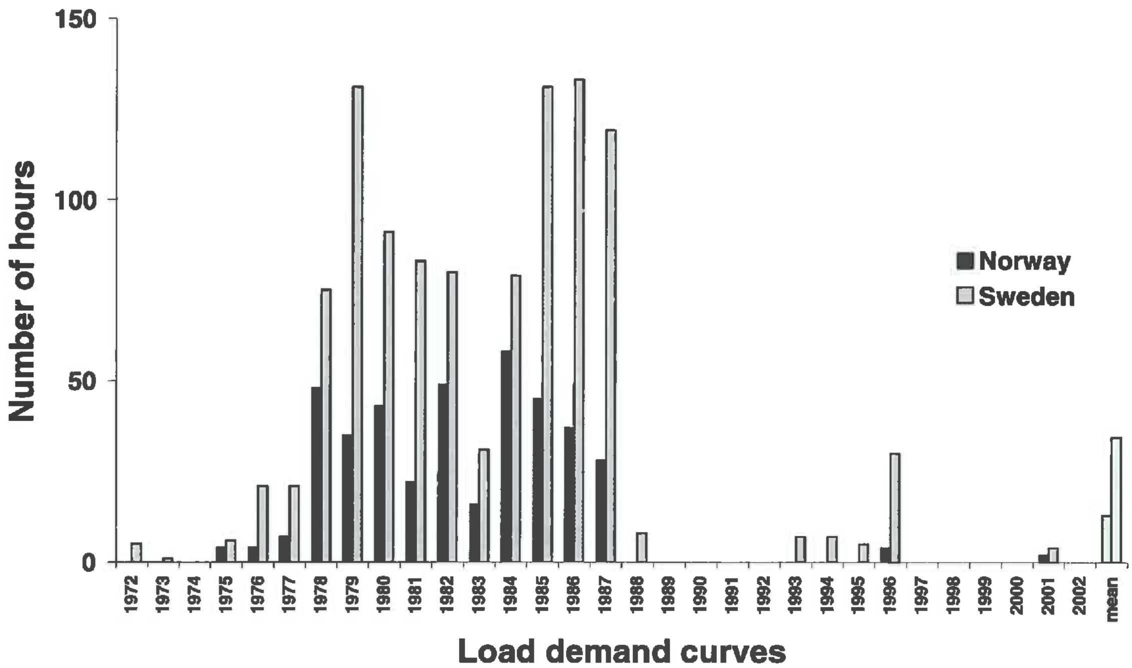

Figure 5: Number of hours with load shedding in Norway and Sweden in 2005.

The potential import during the peak load hour is an important parameter in studies of the capacity balance, cf. [15] and [18]. While Norway is a net importer from Sweden on an annual basis, the trade balance for peak load hours goes in the opposite direction. On average, Sweden can import 839 MW from Norway during the Swedish peek load hour, cf. Figure 6. During the Nordic (Norway+Sweden) peak load, Sweden imports 364 MW on average. Even during the Norwegian peak load hour, Sweden imports 60 MW from Norway on average, cf. Figure 6. The reason for this is that there is an even tighter capacity balance in Sweden during the Norwegian peak load hour. This illustrates why the full import capacity from other countries cannot be included on the supply side in capacity balance analysis. Moreover, our simulations imply that the capacity balance of the peak load hour will not improve (i.e. that the load shedding will not be reduced) if the transmission capacity between Norway and Sweden is increased. The reason is that there already is unused transmission capacity between Norway and Sweden during the extreme peak loads.

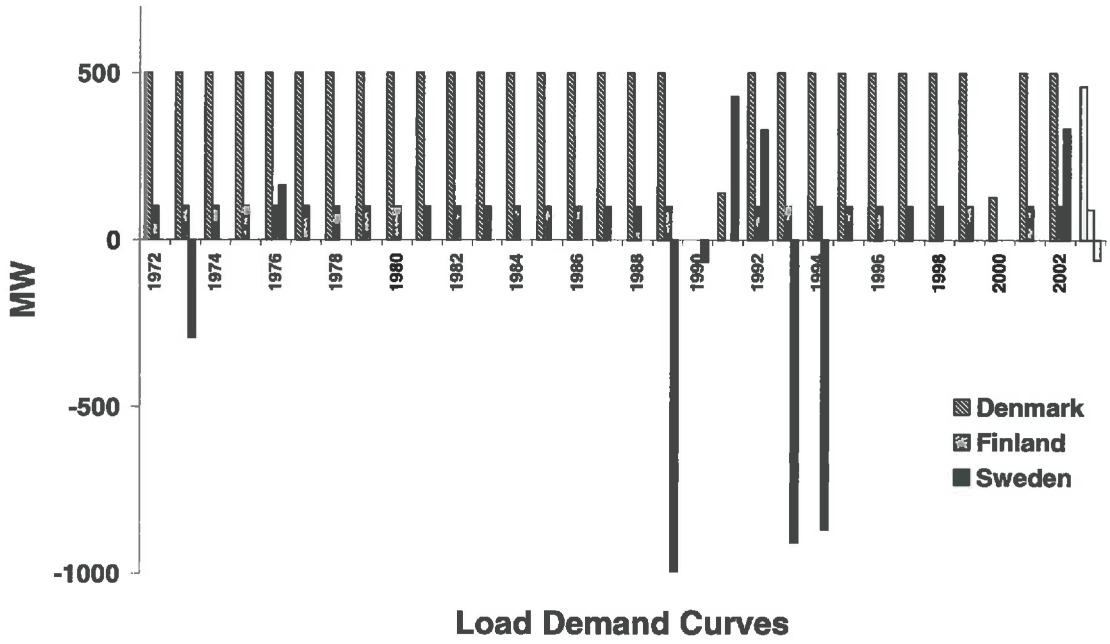

Figure 6: Norwegian net import in the Norwegian peak load hour in 2005.

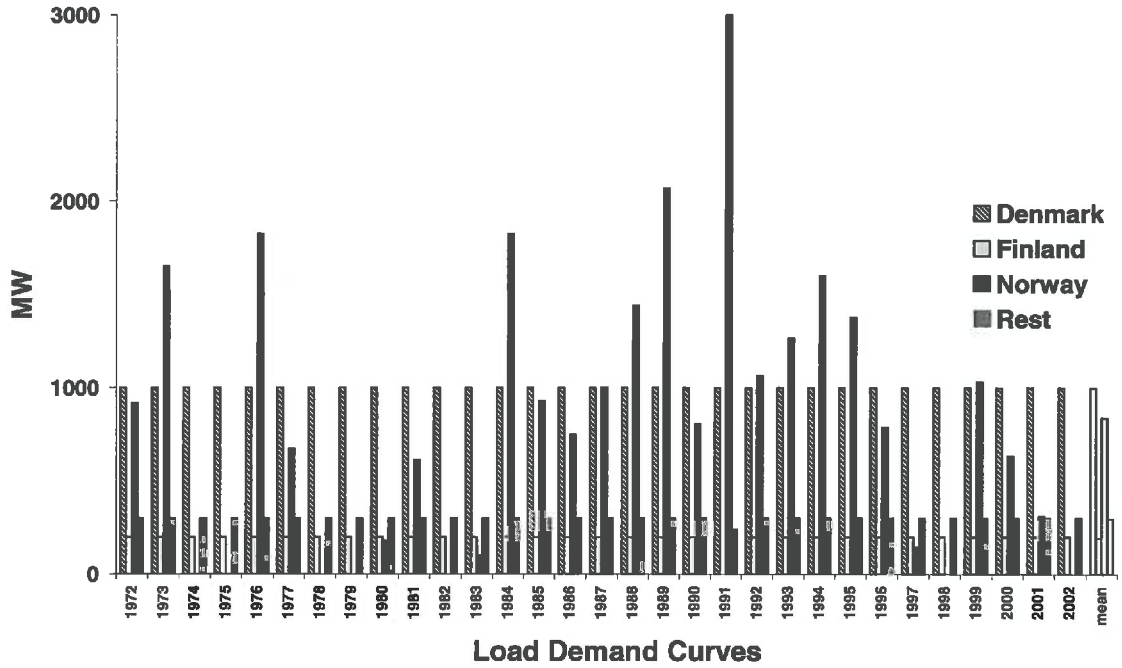

Figure 7: Swedish net import in the Swedish peak load hour in 2005.

Since the potential import e.g. to Sweden depends on the capacity balance in the other model country, e.g. Norway, it is not necessarily the case that the load shedding is largest for the hour with the highest peak demand. In Sweden, the highest peak load is observed for the temperature statistics of 1981, cf. Figure 2. The load shedding during the domestic peak load hour is, however, larger for the load demand curves for the period 1978-1980 and for 1982, Figure 3. The reason is that the import to Sweden from Norway during the Swedish peak load hour is larger for 1981 than for any of the other 4 load demand curves, cf. Figure 7.

The variation in the highest peak load hours within a year is relatively small compared to the variation in the top peak loads for different years, cf. the duration curves for loads in Figure 8 and Figure 9. The upper solid line shows the average over all load demand curves, while the lower solid line shows the average over the load demand curves for the 10 latest years. Figure 8 and Figure 9 show that a load demand curve typically lies above or below another curve in all peak load hours (there are of course exceptions for load demand curves in the closest neighbourhood). As a consequence, the duration curve for load shedding shows a similar pattern, cf. Figure 10 and Figure 11. The upper solid line in Figure 10 is the average of all load demand curves, while the lower solid line is the average of the 10 latest years. The median is zero for all periods. In Figure 11 the upper solid line is the average, the median curve is approximately equal to the average curve for the first period, while the third solid line shows that average for the 10 latest years.

The duration curves for load shedding show why there are many hours with load shedding for some load demand curves and zero hours for other years, cf. Figure 5: If the maximum load shedding for a load demand curve is relatively large compared to another year, then it is likely that there are many hours with load shedding in this year since the variation in the top 200 peak loads are relatively small for the top peak loads.

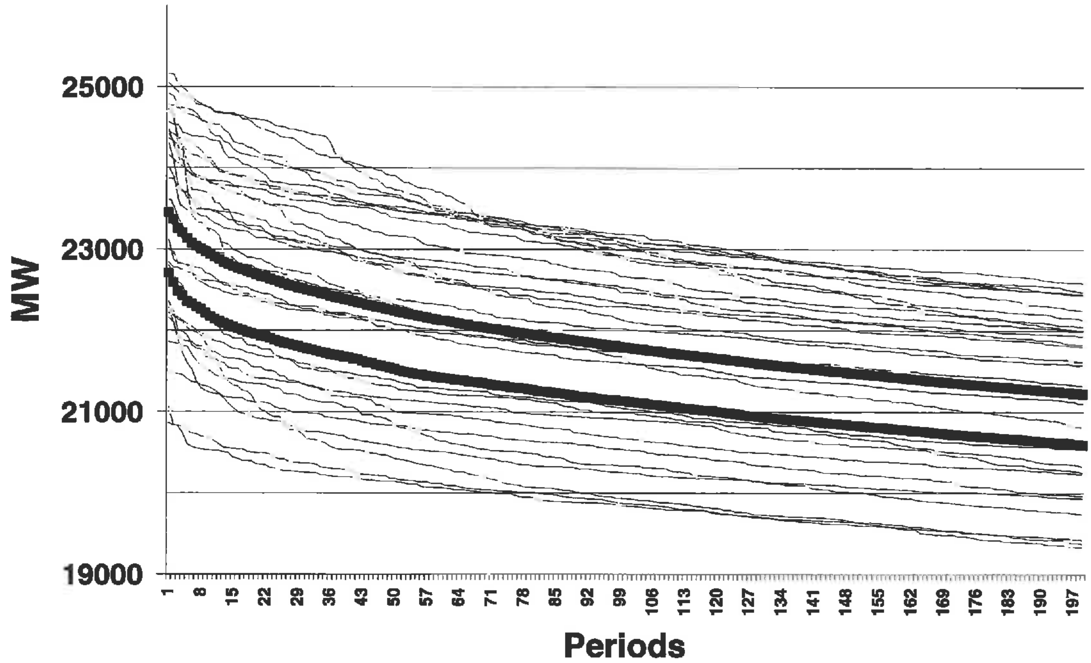

Figure 8: Duration curves for 200 highest loads, Norway 2005 with load demand curves 1972-2002.

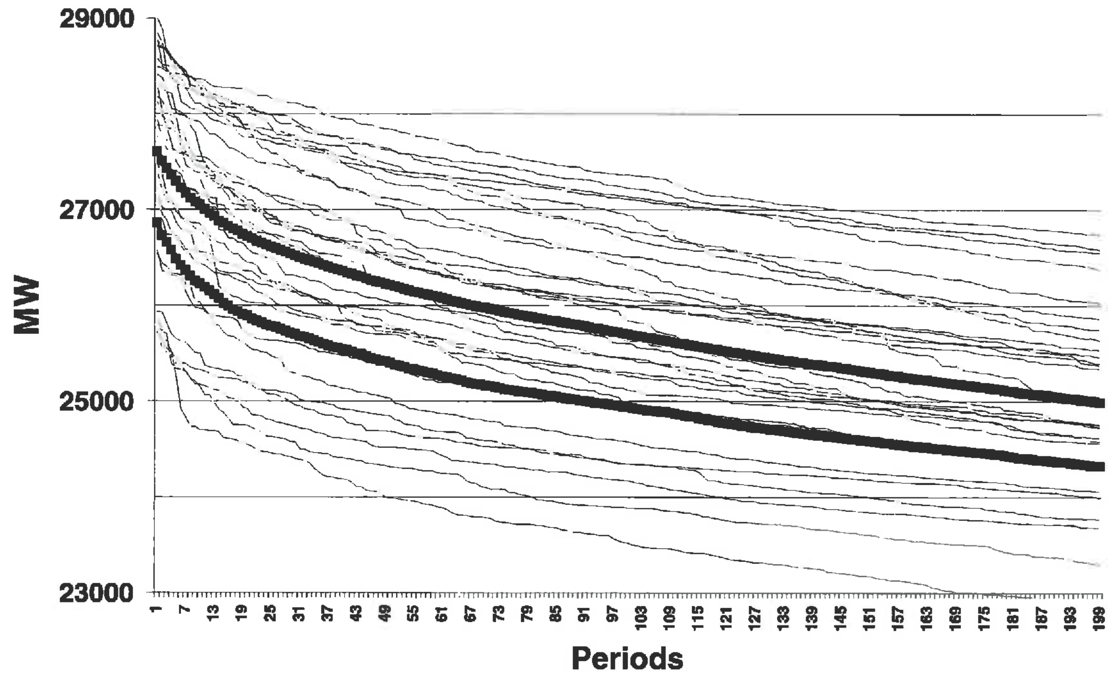

Figure 9: Duration curves for 200 highest loads, Sweden 2005 with load demand curves 1972-2002.

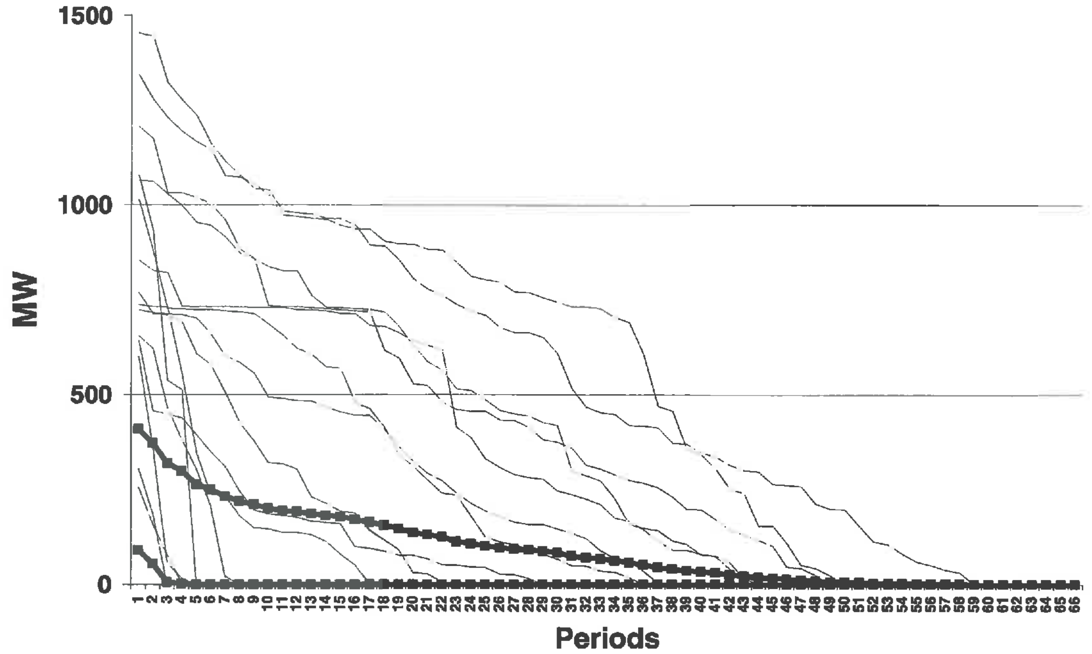

Figure 10: Duration curves for load shedding, Norway 2005 with load demand curves for 1972-2002.

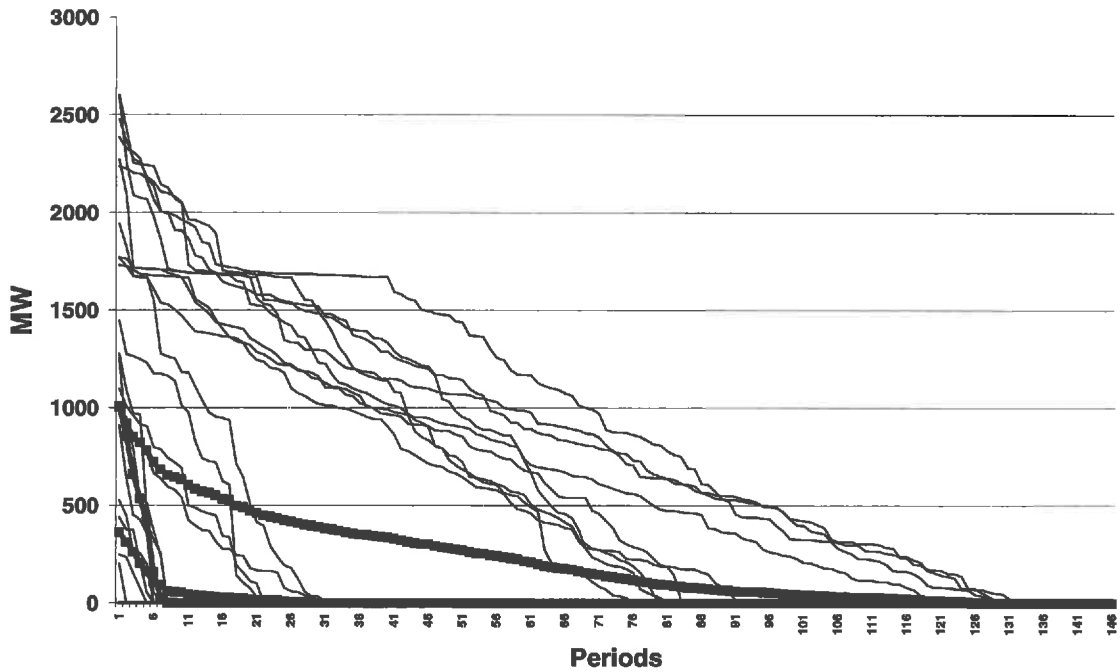

Figure 11: Duration curves for load shedding, Sweden 2005 with load demand curves for 1972-2002.

3.2 ALTERNATIVE SCENARIOS

In the scenario analysis we study the effect of changing some important assumptions. The next Section gives an overview of scenarios and results, while each scenario is discussed more in detail in separate sections.

3.2.1 Overview of scenarios and results

Table III gives an overview of the scenarios we have studied:

Table III: An overview of scenarios.

No.	Scenario	Deviation from baseline
1.	Baseline	
2.	Wind	Sufficient wind power generation is assumed available in Denmark for full utilization of the import capacity to Norway and Sweden from Denmark also during winter-day and late winter-day.
3.	No wind	The import capacity to Norway and Sweden from Denmark is assumed zero during winter-day and late winter-day.
4.	More hydro	The availability of hydropower is increased by 0.05 for Norway and Sweden during winter and late winter.
5.	Less hydro	The availability for hydropower is reduced by 0.05 for Norway and Sweden during winter and late winter.
6.	Boilers	Norwegian boilers are switched off if the price exceeds 450 NOK/MWh.
7.	Reserves	The need for capacity reserves from the supply side is reduced by 1000 MW for Norway and Sweden.
8.	Cable	Norway can import 1200 MW from England in all periods. Prices (in NOK/MWh) are 350 during winter-day, 300 during late winter-day and 250 else.

The average capacity balance over all load demand curves for each scenario for Norway and Sweden is shown in Figure 12 and Figure 13. The average of the largest peak load during the year for the 31 load demand curves is shown by the height of the columns for each scenario. The average supply is shown for technologies where the produced amount varies across scenarios. In addition to the technologies shown in these figures, there is assumed to be 7 MW wind power generation in Norway while there is 8870 MW of nuclear power, 1862 MW CHP and 70 MW wind power assumed in Sweden. The average import to Norway and Sweden during respective peak load hours is given in Figure 14 and Figure 15.

The share of load demand curves that gives load shedding in the estimated peak load hour for 2005 is shown in Table IV, while the average number of hours with load shedding within the whole year is shown in Table V. The share of load demand curves that gives load shedding in the peak load hour and the average number of hours with load shedding within the whole year is lower for Norway than for Sweden in any scenario or period represented in the tables. Moreover, the shares and number of hours are considerably less for the period 1990-2002 than for the whole period 1972-2002 in all since the late 70's and the 80's were colder than the 90's and onwards.

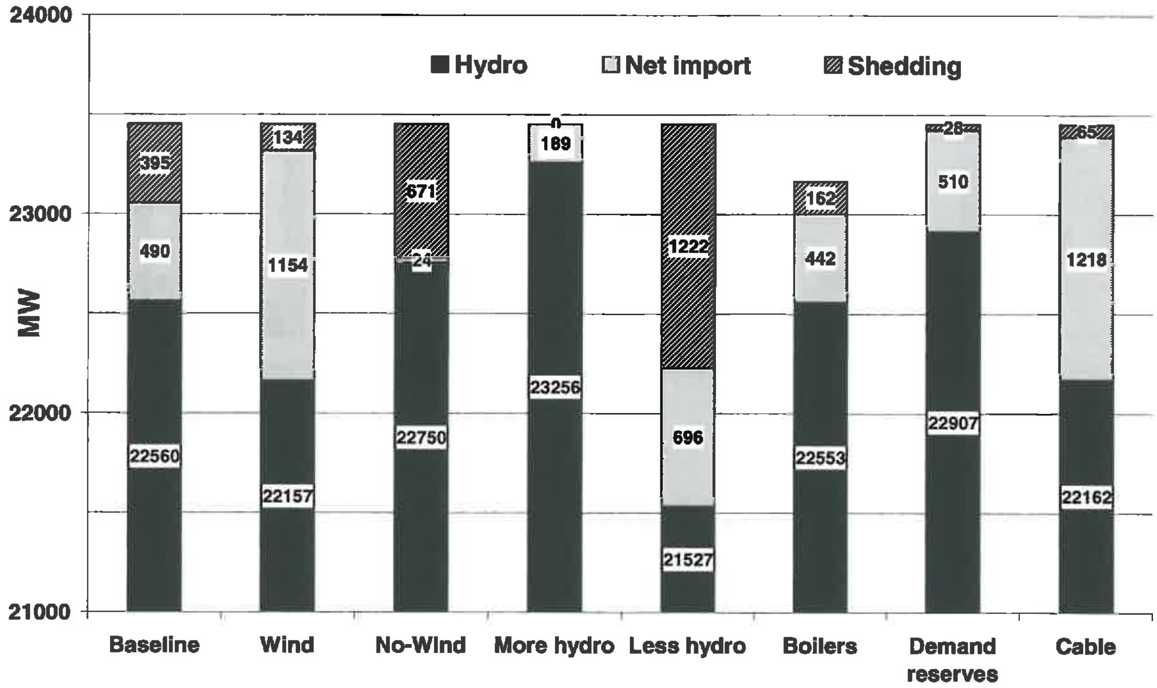

Figure 12: Average capacity balance for Norway during the Norwegian peak load hour 2005.

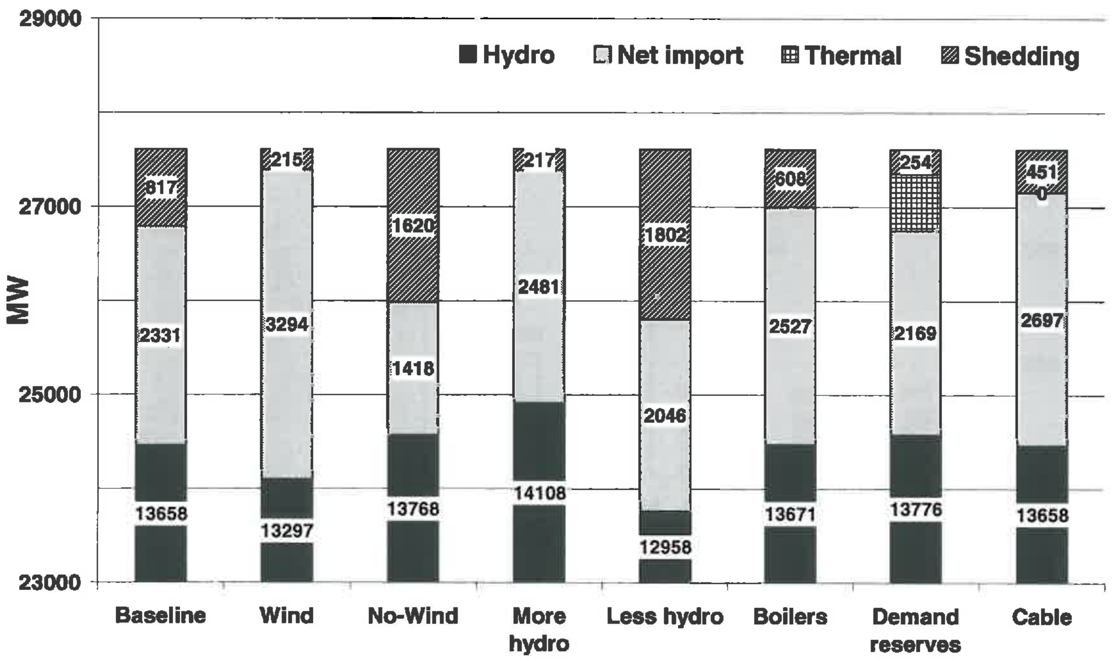

Figure 13: Average capacity balance for Sweden during the Swedish peak load hour 2005.

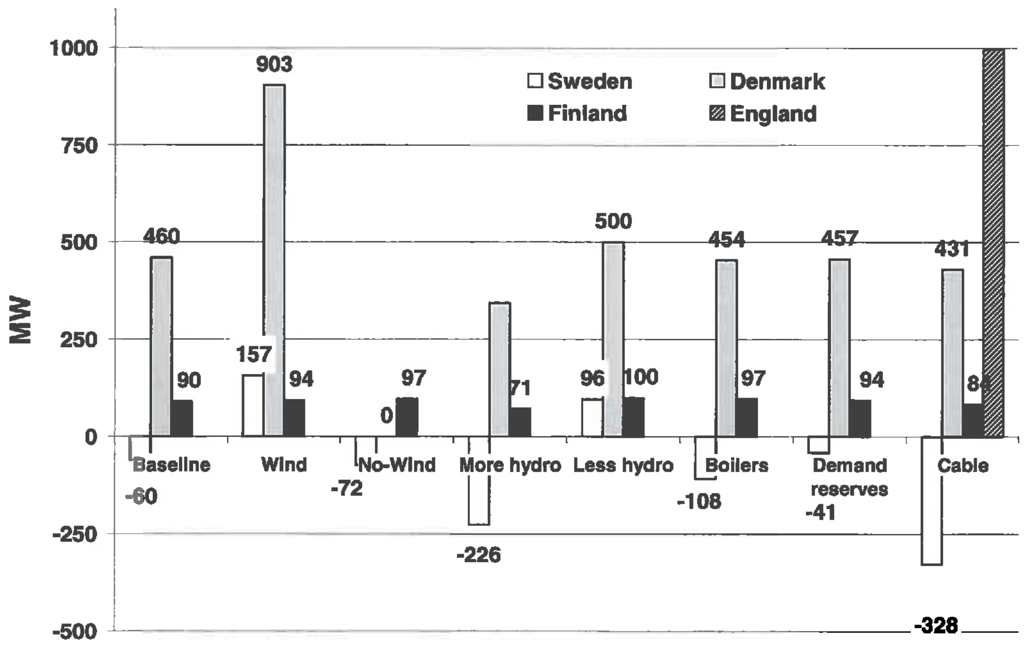

Figure 14: Average net import to Norway during the peak load hour 2005.

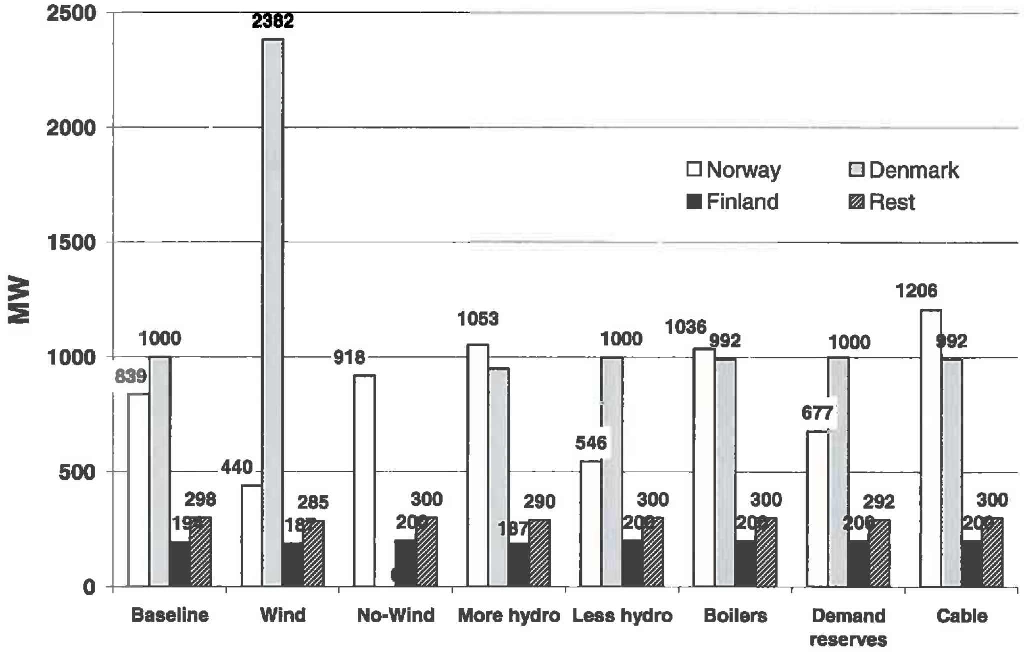

Figure 15: Average net import to Sweden during the peak load hour 2005.

Table IV: The % of load demand curves that gives load shedding during the peak load hour for 2005.

	Load demand curves			
	Norway		Sweden	
	1972-2002	1990-2002	1972-2002	1990-2002
Baseline	45,2	15,4	61,3	38,5
Wind	29,0	-	29,0	-
No Wind	61,3	30,8	74,2	46,2
More hydro	-	-	25,8	-
Less hydro	74,2	38,5	80,6	53,8
Boilers	35,5	-	45.2	15,4
Reserves	19,4	-	29,0	-
Cable	16,1	-	32,3	-

Table V: The average number of hours with load shedding during the whole year for 2005.

	Load demand curves			
	Norway		Sweden	
	1972-2002	1990-2002	1972-2002	1990-2002
Baseline	13,0	0,5	34,5	4,1
Wind	3,4	-	5,2	-
No Wind	38,3	4,4	80,3	17,2
More hydro	- [2]	-	4,6	-
Less hydro	77,0	14,6	107,8	28,2
Boilers	4,8	-	22,8	1,0
Reserves	0,9	-	5,5	-
Cable	1,4	-	14,1	0,1

3.2.2 More import from Denmark during peak load

On very cold days there is often little or no wind. Thus, if there is a particular cold weather type over the whole Nordic region, we can expect reduced wind-power production in Denmark. This reduces the possible export from Denmark to Norway and Sweden. This "cold and calm" effect is already accounted for in the Baseline scenario since the import capacity from Denmark is reduced from 1000 to 500 for Norway and from 2420 to 1000 for Sweden during winter-day and late winter-day. In the *Wind* scenario we assume we assume that the full transmission capacity from Denmark to Norway and Sweden can be utilized during peak demand conditions. The actual flow of electricity from Denmark in non-peak situations is the result of the total balance between supply and demand and the resulting prices.

[2] There is one single hour with load shedding for the 31 load demand curves, but this gives less than 0,05 hours in average, and this is rounded downward to zero.

The average import during the peak load hour is, however, increased by 664 MW for Norway compared to Baseline, which is more than the increase in the transmission capacity, and by 963 MW for Sweden. The explanation for the large increase in the average import to Norway is that the increased export from Denmark to Sweden makes it possible for Sweden to increase the net export to Norway during peak load hours, cf. Figure 14. The average import to Norway from Denmark is increased by 443 MW, which is slightly less than the increase in the transmission capacity since price in the Norwegian peak load hour is less or equal to the Danish price corrected for transmission loss for some load demand curves. In addition, the average import to Norway from Sweden increases by almost 100 MW so that Norway becomes a net importer from Sweden during the Norwegian peak load.

Sine the increase in the import capacity from Denmark is more than twice as large for Sweden than for Norway, it is not surprising that the peak load trade for between Norway and Sweden changes somewhat compared to the baseline scenario. On average, Sweden imports almost 400 MW less from Norway during the Swedish peak load, cf. Figure 15, while the import from Denmark is increased by 1392 MW, and this is close to the increase in the transmission capacity (1420 MW).

The increased availability of Danish import reduces peak load prices for several load demand curves. For such hours it is possible to reduce the hydropower production, which is relatively expensive on the margin close to the available capacity. As a consequence, the average hydropower production is reduced by 403 MW in Norway and by 361 MW in Sweden, cf. Figure 12 and Figure 13. For Norway, the size of the reduction in hydropower production is over 60% of the increase in import. In cases of capacity deficit and load shedding, the hydropower production is, however, maximized and equal to 23102 MW also in the Wind scenario.

The average load shedding are reduced by 260 MW and 602 MW for Norway and Sweden respectively in the Wind scenario. Moreover, the share of load demand curves that give load shedding for 2005 is 29% for the period 1972-2002 for both countries, and this is a reduction of 16.2% and 32.3% respectively for Norway and Sweden, cf. Table IV. The average number of hours with load shedding is reduced from 13 to 3,4 for Norway and from 34,5 to 5,2 for Sweden.

In total, the Wind scenario improves the capacity balance considerably for Norway and Sweden, and more for Sweden than for Norway. For the period after 1990 there are no occasions of load shedding neither for Norway nor for Sweden. In other words, with full availability of import from Denmark and the climate of the 1990's, there is no load shedding.

> With full availability of import from Denmark and the climatic conditions of the 1990's, there is no need for load shedding in Sweden and Norway during peak load conditions.

3.2.3 Zero import from Denmark during peak load

In the *No wind* scenario we consider the worst-case scenario regarding the import from Denmark: we assumed that there is no surplus generation capacity in Denmark for export to Norway and

Sweden. The import capacity to Norway and Sweden from Denmark is set to zero during winter-day and late winter-day, compared to 500 MW and 1000 MW respectively in the Baseline scenario.

The average net import is reduced by 466 MW for Norway (to only 24 MW) and by 913 MW for Sweden, cf. Figure 12 and Figure 13. For Sweden, the average net import from Norway during the Swedish peak load hour increases by 79 MW, but the import from Norway is reduced for some load demand curves.

The reduced availability of Danish import increases peak load prices for several load demand curves. For such hours it is optimal to increase the hydropower production to the maximum, even though this is relatively expensive on the margin. As a consequence, average hydropower production during peak loads are increased by 190 MW in Norway and by 110 MW in Sweden.

Since the reduced import is only partly offset by increased hydropower production, the average load shedding of the peak load hour is increased by 276 MW for Norway and by 803 MW for Sweden. Moreover, the share of load demand curves that give load shedding for 2005 increases by 16,1% and 12,9% for Norway and Sweden respectively for the period 1972-2002 and by 15,4% and 7,7% for the period 1990-2002, cf. Table IV. Thus, the share of years with load shedding increases more for Norway than for Sweden even though the Swedish capacity balance is more affected than the Norwegian capacity balance. One possible explanation for this is that the large Swedish deficit in the Swedish peak load hours gives a "level 3" shedding which by assumption gives a socio-economic costs of 2200 NOK/MWh. In this case, it will obviously be optimal to export as much as possible from Norway to Sweden given that there is zero load shedding in Norway. When the exported amount is so large that an extra MW exported generates 1 MW load shedding in Norway, the cost of increased export to Sweden is 2000 NOK/MWh since this is the cost of load shedding in Norway for each MWh. But this additional export generates a $2200(1-0.07)=2046$ NOK reduction in the shedding costs for Sweden. Thus, it is optimal to increase the export of power from Norway to Sweden in some hours even though this *creates* a capacity deficit for Norway.

The number of hours with load shedding, cf. Table V, increases by 25,3 hours for Norway and by 45,8 hours for Sweden. In total, the No wind scenario weakens the capacity balance considerably for Norway and Sweden, and more for Sweden than for Norway.

> Without import from Denmark, expected load shedding is 4,4 hours per year for Norway and 17,2 hours per year for Sweden, even with the climatic conditions of the 1990's

3.2.4 Increased availability for hydropower

The availability of the existing hydropower capacity potential during peak loads is less than 100 % for several reasons. Firstly, it may not be possible to use the full capacity due to transmission constraints. Secondly, reduced head reduces generation capacity when reservoirs are less than

100 % full. Thirdly, some generators may be out of operation because of failure, maintenance or upgrading. Finally, the actual production is lower than installed capacity for most run-of-river plants during the winter.

In the baseline scenario, the availability during winter, late winter and else for Norway and Sweden is set to (89%,80%,95%) and (86%,86%,95%) respectively. In the *More hydro* scenario, we assume increased availability for hydropower. The availability is increased to (94%, 85%, 95%) and (91%,91%,95%) for Norway and Sweden respectively. This corresponds to a 1383 MW increase for Norway and 812 MW for Sweden during winter and late winter.

The average hydropower production during the peak load hour is increased by 696 MW for Norway and 450 MW for Sweden since the available capacity has increased and all the available capacity is used during hours with capacity deficit. For Norway, the average import is reduced with 301 MW, cf. Figure 12, and this includes a 166 MW increase in the net export to Sweden, cf. Figure 14. For Sweden, the average net import is increased by 150 MW, cf. Figure 13. The average import from Norway during the peak load hour is increased by 214 MW since the capacity balance has improved more in Norway than in Sweden, cf. Figure 15, while the import from others are reduced. The reason is that the increased availability of hydropower and the increased import has reduced the price, and reduces the average import to Sweden from other regions in the optimal solution.

As a consequence of increased hydropower production in the peak load hours, the average load shedding for Norway during the peak load hours is zero for Norway, and this is a reduction of 395 MW, cf. Figure 12. The increased hydropower production plus the increased import to Sweden, reduces the average load shedding for Sweden during the Swedish peak load hour by 600 MW, down to 217 MW, cf. Figure 13.

The % of load demand curves that gives load shedding during the peak load hour is zero for Norway for the More hydro scenario, compared to 45,2% in the baseline scenario for the period 1972-2002 and 15,4% for the period 1990-2002, cf. Table IV. For Sweden, the share is 25,8% and zero for the two periods, compared to 61,3% and 38,5% in the Baseline scenario. While there are no hours with load shedding on average for Norway in this scenario, Sweden has 4,6 hours of load shedding on average for the period 1972-2002, cf. Table V. The reduction in the average number of hours with load shedding is 13 hours for Norway and almost 30 hours for Sweden.

In total, the capacity balance is considerably improved in the More hydro scenario. For Norway, the problem with capacity deficit is eliminated; there is load shedding only for one single hour for 2005 in the set of load demand curves from 1972-2002. For Sweden, there is load shedding for the highest peaks also in this scenario, but the average number of hours is greatly reduced from the Baseline scenario.

> With optimistic assumptions on hydro power availability, load shedding is not observed for Norway for any scenarios. For Sweden there is no load shedding for the period 1990-2002, but an average of 4,6 hours per year for the whole period 1970-2002.

3.2.5 Reduced availability for hydropower

In the baseline scenario, the availability of hydropower during winter, late winter and else for Norway and Sweden is set to (89%, 80%, 95%) and (86%, 86%, 95%) respectively. In the *Less hydro* scenario, we assume reduced availability for hydropower. The availability is set to (84%,75%,95%) and (81%,81%,95%) for Norway and Sweden respectively. This corresponds to a 1383 MW decrease for Norway and 812 MW for Sweden during winter and late winter.

The average hydropower production is reduced by 1033 MW for Norway and by 700 MW for Sweden. Moreover, the effect of *reduced* available capacity for hydropower has a stronger effect on average equilibrium production than a corresponding *increase* in the available capacity, cf. the previous Section. The reason for this is that the production is maximized for several load demand curves when the hydropower capacity is low. Thus, the effect of changing the available capacity by one unit is closer to 1 when the available capacity is low initially.

For Norway, the average import during the peak load hour is increased by 206 MW, while the Swedish import is reduced by 285 MW. The reason for this is that the capacity balance has weakened more for Norway than for Sweden. Thus, the Norwegian net export to Sweden during the peak load hour for Norway has been reduced with 156 MW and turned in a net import, cf. Figure 14 and Figure 15. The import from other countries to Norway and Sweden is, on average, equal to the assumed available transmission capacity during the respective peak load hours for Norway and Sweden in the Less hydro scenario.

Although the direct effect of reduced availability of hydropower is larger for Norway than for Sweden, the average increase in load shedding during the peak load hour is largest for Sweden 827 MW and 985 MW respectively, cf. Figure 12 and Figure 13, since Norwegian net import from Sweden is increased during peak load hours.

The Less hydro scenario is the worst scenario for the capacity balance by all measures considered here. There is load shedding in the bulk of the load demand curves for Norway (74,2%) and Sweden (80,6%), cf. Table IV. Even for the period starting in 1990 there is load shedding for many load demand curves; 38,5% for Norway and 53,8% for Sweden. The increase is 29% and 19,3% for Norway and Sweden respectively. The average number of hours with load shedding is 77 for Norway and 107,8 for Sweden in the whole period, and 14,6 and 28,2 respectively in the period after 1990, cf. Table V. The increase for the whole period is 64 and 73,3 hours for Norway and Sweden respectively.

In total, the Less hydro scenario is the worst scenario for the capacity balance in Norway and Sweden. The largest amount of load shedding after 1990 is 1983 MW for Norway and 2464 MW for Sweden. Thus, if a 5% reduction in the availability of hydropower

> With pessimistic assumptions on hydro power availability, there is considerable load shedding in both Norway and Sweden during peak demand hours, even with the climatic conditions of the 1990's

for winter and late winter is a realistic assumption, the possibility for load shedding in 2005 cannot be disregarded even if the mild climate from the 90's continues and we assume some flexibility on the demand side.

3.2.6 Price elasticity of electrical boilers

In the baseline scenario, the demand side of the model is assumed inelastic; the same amount of electricity is consumed no matter how large prices are. This may be a good description of the bulk of consumption since end-users traditionally have been protected from short run price fluctuations. However, if end-users are exposed to the spot prices and we experience several years with high electricity prices, at least in some periods, the overall demand may be reduced and more sensitive to prices. Traditionally, some electrical boilers have been disconnected in periods with high electricity prices. In the *Boilers* scenario, we assume that the Norwegian boilers (628 MW) are shut down if the electricity price exceeds 450 NOK/MWh.

The reduced demand in Norway during the highest peak load hours, reduces the price in Norway in some of these hours. As a consequence, the net export to Sweden during the Norwegian peak load hour increases by 48 MW, cf. Figure 12 and Figure 14. The average export to Sweden during the Swedish peak load hour increases by 197 MW, cf. Figure 15, and the corresponding export for Norway is $197/0.93 = 212$ MW. Thus, the average capacity balance during the peak load hour is improved almost as much for Norway and Sweden (288 MW vs 218 MW). The average load shedding during the peak load hour is reduced by 233 MW and 208 MW in Norway and Sweden respectively, cf. Figure 12 and Figure 13.

The share of load demand curves with load shedding during the peak load hour is reduced by 9,7% for Norway and by 16,1% during 1972-2002, cf. Table IV. For the period after 1990 the share of load demand curves with load shedding for Norway and Sweden is zero and 15,4% respectively, while the average number of hours with load shedding is zero and one hour respectively.

In total, the capacity balance is considerably improved in the Boilers scenario, even though there are many problematic years peak load hours during the late 70's and the 80's in this scenario. The disconnection of electrical boilers in Norway improves the capacity balance approximately equally much for Norway and Sweden since Sweden increases the import from Norway considerably during the Swedish peak load hour compared to the Baseline scenario.

> If electrical boilers in Norway respond to short term price signals, there is no load shedding in Norway for the climatic conditions of the 1990's, and only minor load shedding in Sweden.

3.2.7 Demand-side reserves

The system operators need reserves to secure the stability of the electrical system due to continuous variations in demand and in cases of technical fallouts. In the Baseline scenario, the total capacity reserve requirements are 1513 MW for Norway and 1733 MW for Sweden.

Traditionally, the system operators have acquired reserves from producers. The system operators can in principle use secondary reserves from the demand-side too, provided the demand side is prepared to deliver such reserves. In the *Reserves* scenario, we assume that 1000 MW reserves are provided from consumers in both Norway and Sweden.

The supply side of the capacity balance is improved by 1000 MW when the capacity reserve requirement for the supply-side is reduced by this amount. Since the demand is inflexible in our model, the demand side of the capacity balance is unchanged. Thus, the capacity balance is improved when some reserves are acquired from consumers.[3]

The average production of hydropower in Norway during the peak load hour is increased by 347 MW. This is considerably less than the 1000 MW reduction in reserves acquired from hydropower in Norway. The reason for this is that the efficiency of using more water already is relatively low in the Baseline scenario during the peak loads. Thus, the optimal supply in the peak load hour does not change for many load demand curves even though it is *possible* to increase production. The production is, however, maximized if there is load shedding during the peak load hours. For such hours, the hydropower production is 24102 MW, and this is 1000 MW increase compared to the Baseline scenario.

In Sweden, thermal capacity provides 1574 MW reserves in the Baseline scenario during the peak hours, while hydropower capacity provides 159 MW. Thus, available capacity is increased for thermal production and hydropower production in the Reserves scenario. The marginal costs for these technologies are, however, high during the peak load hour. As a consequence, the average increase in production is 607 MW for thermal power and 118 MW for hydropower.

The net import to Norway during the peak load hour increases by 20 MW on average, cf. Figure 12, and this corresponds approximately to the reduced export to Sweden, cf. Figure 14. The Swedish import is reduced by 162 MW, cf. Figure 13, and this is equal to the reduced import from Norway, cf. Figure 15. An explanation for the reduced net export from Norway to Sweden during the peak load hours for Norway and Sweden is that the there are more hours with capacity balance deficit and load shedding in Sweden than in Norway in the Baseline scenario. As a consequence, 1000 MW extra capacity reduces the number of hours with load shedding more in Sweden than in Norway, cf. Table V.

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[3] This finding supports the view that reserves should be acquired from the demand side also so that the flexibility on both sides of the market is utilized. This reduces the socio-economic costs of holding reserves, and the system operators' expenses are reduced. On the other hand, this finding does not provide a solid basis for the view that reserves from the demand side of the market should obtain a larger premium for their reserves. The optimal design of an incentive structure for the provision of reserves needs a more detailed representation of different kinds of markets, such as the market for capacity reserves, the spot market and the regulating power market. The interactions between these markets are dealt with in [24].

On average, the Norwegian production and import have increased during the Norwegian peak load hour. As a consequence, the average load shedding is reduced from 395 MW to 28 MW, cf. Figure 12. For Sweden, the reduced import during the peak load hour offsets only parts of the increase in production in Sweden on average. As a consequence, the average load shedding for Sweden is reduced from 815 MW in the Baseline scenario to 254 MW, cf. Figure 13.

In the Reserves scenario there is zero load shedding in Norway and Sweden in the period after 1990. For the whole period 1972-2002, there is load shedding during the peak load hour for 19,4% and 29% of the load demand curves for Norway and Sweden respectively. These shares are less than half than the corresponding shares in the Baseline scenario, cf. Table IV. Moreover, the average number of hours with load shedding within the whole 1972-2002 period is less than 1 for Norway and 5,5 for Sweden, compared to 13 hours and 34,5 hours respectively in the Baseline scenario.

In total, the capacity balance is considerably improved in the Reserves scenario. There is no capacity deficit for the period after 1990. For the whole period, the average load shedding is only 0,9 hours for Norway, but there is load shedding during the peak load hour in almost 1 out of 5 years. For Sweden, the capacity problems are larger than for Norway, but they are considerably reduced compared to the Baseline scenario.

> With assumption that 1000 MW of reserves is provided by the demand side in both Sweden and Norway (2000 MW in total), there is no load shedding with the climatic conditions of the 1990's. For the whole simulation period 1970-2000, average load shedding is 0,9 MW for Norway and 5,5 MW for Sweden

3.2.8 Cable

In May 2003 Statnett applied for a concession to build the 1200 MW "North Sea Interconnector" between Norway and England. Their application was, however, rejected since there was too much uncertainty about the socio-economic value of the project. In the *Cable* scenario we study how a 1200 MW cable to England would have affected the capacity balance. We assume that 1200 MW can be exchanged in both directions throughout the year, and that the electricity prices in England are 350 NOK/MWh during winter-day and 250 NOK/MWh else.

On average, Norway imports 996 MW from England during the peak load hour, cf. Figure 14. Thus, Norwegian peak load prices are significantly reduced. As a consequence, the average export to Sweden during the Norwegian peak load hour increases with 268 MW, while the net import from Denmark and Finland is reduced with 35 MW.

The extra import from England gives fewer hours with load shedding. In Norway, the load shedding is reduced from 13 hours to 1,4 hours and in Sweden the reduction is from 34,5 hours to 14,1 hours, cf. Table V. Since peak load prices are reduced for some years the average power production during peak load hours is reduced by almost 400 MW in Norway. The average load shedding is reduced from 395 MW in the Baseline scenario to 65 MW. For Sweden, the average load shedding is reduced from 817 MW to 451 MW as a result of increased import from Norway.

Compared to the Reserves scenario, which improved the capacity balance in both Norway and Sweden by 1000 MW initially, the share of load demand curves with load shedding during the peak load hour is less for Norway but larger for Sweden, cf. Table IV. The differences are, however, small. The average number of hours with load shedding for Norway is slightly larger in the Cable scenario than in the Reserves scenario (0,9 hours vs 1,4 hours), while the Reserves scenario gives considerably fewer hours with load shedding for Sweden (5,5 hours vs 14,1 hours), cf. Table V. The reduction in number of hours with load shedding compared to the Baseline scenario, is, however, larger for Sweden than for Norway.

A cable to England would almost have eliminated the capacity deficits for the climatic conditions of the 1990's. For the whole period, the average load shedding is only 1,4 hours for Norway and 14,1 hours for Sweden.

In total, the Cable scenario almost eliminates the capacity deficits for load demand curves in the period after 1990. For the whole period, the average load shedding is only 1,4 hours for Norway, but there is load shedding during the peak load hour in almost 1 out of 6 years. For Sweden, the capacity problems are larger than for Norway, but they are considerably reduced compared to the Baseline scenario.

4 CONCLUSIONS

4.1 Main findings

(a) There is some load shedding for Norway and Sweden in the Baseline scenario for 2005, which is slightly pessimistic.
(b) There is more load shedding for Sweden than for Norway.
(c) Our forecast for the annual electricity balance is largely in accordance with Nordel's forecasts.
(d) Our peak load forecast for Norway and Sweden is 25161 MW and 28992 MW respectively. For Norway, this forecast is over 1000 MW larger than Nordel's forecasts. For the period 1990-2002, the peak load forecast is very similar to Nordel.
(e) The climate from the 70's and the 80's is considerably colder than the climate of the 90's and onwards. The capacity balance is therefore considerably better for the load demand curves after 1990.
(f) Norway and Sweden import significant amounts of electricity from Denmark both on annual basis and during peak load hours.
(g) While Norway is a net importer from Sweden on an annual basis, Sweden imports some power from Norway during the peak loads in the Nordic region. The average import to Sweden from Norway is 839 MW during the Swedish peak load hour.
(h) The capacity balance in the peak load hour in Norway and Sweden will not improve if the transmission capacity between Norway and Sweden is increased.
(i) The load demand curves for the period 1990-2002 gives zero load shedding for Norway and Sweden
  - if the Danish capacity balance is so good that the full transmission capacity from Denmark to Norway and Sweden can be utilized during peak loads, or
  - if the availability of hydropower is increased by 5% during winter and late winter, or
  - if 1000 MW reserves are available from consumers in Norway and in Sweden, or
  - if a cable is built to England or another country and 1200 MW can be imported on this cable throughout the year,
  - while there is zero load shedding only in Norway if electrical boilers in Norway are price elastic
(j) For the whole period 1972-2002 the same scenarios gives considerable improvements for the capacity balance even though there is some load shedding. In the scenario with increased availability of hydropower there is load shedding for Norway only in a single hour in one year.
(k) Even if the initial effect of changed assumptions affects the capacity balance in Norway and Sweden differently, the overall equilibrium effect will typically be relatively similar for both countries as a consequence of changed trade pattern between them.

4.2 PROSPECTS FOR 2005

If one believes that the demand is inflexible and that the system operators only will use supply-side reserves, the probability for load shedding during the peak load hour is approximately 15% for Norway and more than the double share for Sweden even if the mild climate of the 90's continues and the import possibility from Denmark and the availability of hydropower are as assumed in the baseline scenario. On average, there are 0,5 hours with load shedding in Norway under these assumptions and 4,1 hours in Sweden. A worst-case scenario with less availability of hydropower *and* zero import from Denmark during the peak load *and* a colder climate would be considerably worse for the capacity balance than the baseline scenario, but the combined probability for all these events is very low. The probability that one of these events will occur is, however, considerably larger, and the corresponding average number of hours with load shedding are in the range of 4 to 15 for Norway and 17 to 35 for Sweden.

If, however, one believes that there is some domestic flexibility on the demand side *and* that system operators are able to use reserves from the demand side of the market, the probability for load shedding during the peak load hour is close to zero if the mild climate continues and the availability of Danish import and hydropower is normal.

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APPENDIX A: MATHEMATICAL DESCRIPTION

Sets:

SALL	-	set of all periods
SEASON	-	set of seasons
SDAY	-	set of all workday periods
SWKD	-	set of all weekend periods
SNGT	-	set of all night periods
LPER	-	set of load periods
TECH	-	set of generation technologies
$TECH^{en}$	-	set of those generation technologies which has endogenously determined production
$TECH^{ex}$	-	set of those generation technologies where production exogenously given
IMPSEG	-	set of import (and export) segments in addition to countries in REG
DEMSEG	-	set of demand segments
REG	-	set of regions
SHEDLEVEL	-	set of shed levels

Indexes:

t	-	time period, $t \in$ SALL
s	-	season, $s \in$ SEASON
l	-	load period, $l \in$ LPER
i	-	technology, $i \in$ TECH
j	-	demand segment, $j \in$ DEMSEG
k	-	import segment, $k \in$ IMPORT
e	-	export segment, $e \in$ EXPORT
h	-	counter for weights, $h \in \{1, 2, 3\}$
n, u	-	region, $n,u \in$ REG
sh	-	shed levels

Constants:

T	-	number of time periods
NHR_t	-	number of hours in period t
$PMAX_{ni}$	-	maximum power capacity region n technology i (MW)
$RMAX_{ni}$	-	relative resource use at maximum power for region n technology i (MWh/MWh)
$PBEST_{ni}$	-	point of best efficiency region n technology i (% of PMAX)
$RBEST_{ni}$	-	relative resource use at point of best efficiency for region n technology i (MWh/MWh)
VC_{ni}	-	variable cost region n technology i (\$/MWh)
W_{ni}	-	maximum resource use in production region n technology i (GWh/year)
PPS_n	-	pumped storage capacity region n (MW)
TPS_n	-	number of hours storage capacity pumped storage region n
$ETAP_n$	-	efficiency pumping cycle region n
$IMPMAX_{nkt}$	-	maximum import region n segment k in period l
$EXPMAX_{nkt}$	-	maximum import region n segment k in period l
$VCIMP_{nkt}$	-	variable cost import region n segment k in period l

$AVAIL_{nit}$	-	availability region n technology i in period t
R_{nt}	-	total spinning and non-spinning reserve requirement in region n period t (MW)
$DMAX_{njt}$	-	maximum demand region n segment j in period t (MW)
$DMIN_{njt}$	-	minimum demand region n segment j in period t (MW)
ACC_{nj}	-	accumulation capacity region n demand segment j (MW)
$TACC_{nj}$	-	maximum number of hours for demand accumulation, region n segment j
$VCACC_{nj}$	-	variable accumulation cost region n demand segment j ($/MWh)
$SRAV_{nj}$	-	short-run added-value region n demand segment j ($/MWh)
$SHEDCOST_{njt}$	-	variable cost of shedding for region n demand segment j in period t ($/MWh)
$EXPMAX\_B_{nut}$	-	transmission capacity from region n to region u
$IMPMAX\_B_{nut}$	-	transmission capacity from region u to region n
$MAXSHED_{nsh}$	-	maximum shedding in region n shed level sh
$LOSS_{nut}$	-	% loss in the transmission from region n to region u in period t

Positive variables:

p_{nit}	-	generation region n technology i in period t (MW)
r_{nit}	-	resource use region n technology i in period t (MW)
$lambda_{nhit}$	-	weight of point h in resource use curve technology i region n
cp_{nit}	-	generation cost of technology i in region n period t ($)
pg_{nt}	-	pumped storage generation in region n period t (MW)
pp_{nt}	-	pumped storage pumping in region n period t (MW)
stp_{nt}	-	pumped storage volume region n at the start of period t $\in$ {1..T+1} (MWh)
imp_{nkt}	-	import, region n segment k, period t (MW)
exp_{nkt}	-	export, region n segment k, period t (MW)
$cimp_{nkt}$	-	cost of net import region n segment k in period t ($)
d_{njt}	-	demand, region n segment j, period t (MW)
dg_{njt}	-	demand from grid, region n segment j, period t (MW)
vd_{njt}	-	value of demand region n segment j in period t ($)
$dacc_{njt}$	-	accumulated demand region n segment j at the start of period t $\in$ {1..T+1} (MWh)
$cacc_{njt}$	-	accumulation cost region n demand segment j in period t ($)
$shed_{njtsh}$	-	shedding of load region n segment j in period t (MW)
$cshed_{njt}$	-	cost shedding of load region n segment j in period t ($)
exp_b_{nut}	-	region n's export to region u
imp_b_{nut}	-	region n's import from region $_u$

Relations:

$$\mathrm{MAX}\left[\sum_{t=1}^{T}\sum_{n}\left\{\sum_{j} vd_{njt} - \sum_{j} cacc_{njt} - \sum_{i} cp_{nit} - \sum_{k} cimp_{nkt} - \sum_{j} cshed_{njt}\right\}\cdot NHR_t\right] \quad \text{(A1)}$$

subject to:

$$\sum_i p_{nit} + pg_{nt} + \sum_{u\in IMPSEG}(imp_{nut} - exp_{nut}) + \sum_{u\in REG}(imp\_b_{nut} - exp\_b_{nut}) + \sum_{j,sh} shed_{njtsh} - \sum_j dg_{njt} - pp_{nt} = 0 \quad \forall n,t \quad \text{(A2)}$$

$$r_{nit} - RBEST_{ni} \cdot PBEST_{ni} \cdot PMAX_{ni} \cdot AVAIL_{nit} lambda_{n2it} - RMAX_{ni} \cdot PMAX_{ni} \cdot AVAIL_{nit} lambda_{n3it} = 0 \quad \forall n,i,t \quad \text{(A3)}$$

$$p_{nit} - PBEST_{ni} \cdot PMAX_{ni} \cdot AVAIL_{nit} lambda_{n2it} - PMAX_{ni} AVAIL_{it} lambda_{n3it} = 0 \quad \forall n,i,t \quad \text{(A4)}$$

$$\sum_h lambda_{nhi} = 1 \quad \forall n,i \quad \text{(A5)}$$

$$\sum_t NHR_t \cdot r_{nit} \le W_{ni} \cdot 1000 \quad \forall n,i \quad \text{(A6)}$$

$$\sum_i p_{nit} + pg_{nt} \le \sum_{i\in TECH^{en}} PMAX_{ni} \cdot AVAIL_{nit} + PPS_n - R_{nt} \quad \forall n,t \quad \text{(A7)}$$

$$stp_{n,t+1} - stp_{nt} + NHR_t \cdot pg_{nt} - ETAP_n \cdot NHR_t \cdot pp_{nt} = 0 \quad \forall n,t \quad \text{(A8)}$$

$$dacc_{nj,t+1} - dacc_{njt} + NHR_t \cdot d_{njt} - NHR_t \cdot dg_{njt} = 0 \quad \forall n,j,t \quad \text{(A9)}$$

$$cacc_{njt} - VCACC_{nj} \cdot NHR_{nt} \cdot (d_{njt} - dg_{njt}) \ge 0 \quad \forall n,j,t \quad \text{(A10)}$$

$$dcacc_{njt} = TACC_{nj} \cdot ACC_{nj} \quad \forall n,j; t \in \{1, T+1\} \quad \text{(A11)}$$

$$cp_{nit} = VC_{ni} \cdot r_{nit} \quad \forall n,i,t \quad \text{(A12)}$$

$$vd_{njt} = SRAV_{nj} \cdot d_{njt} \quad \forall n,j,t \quad \text{(A13)}$$

$$cimp_{nkt} = VCIMP_{nkt}\left(imp_{nkt} \cdot (1 + LOSS_{nkt}) - exp_{nkt} \cdot (1 - LOSS_{nkt})\right) \quad \forall n,k,t \quad \text{(A14)}$$

$$cshed_{njt} = \sum_{sh} SHEDCOST_{njtsh} shed_{njtsh} \quad \forall n,k,t \quad \text{(A15)}$$

$$imp\_b_{nut} = exp\_b_{unt}(1 - loss_{un}) \quad \forall n,u,t \quad \text{(A16)}$$

Bounds:

$p_{nit} \le AVAIL_{nit} \cdot PMAX_{ni}$	$\forall n,i,t \in TECH^{en}$	(A17)
$p_{nit} = AVAIL_{nit} \cdot PMAX_{ni}$	$\forall n,i,t \in TECH^{ex}$	(A18)
$pg_{nt} \le PPS_n$	$\forall n,t$	(A19)
$pp_{nt} \le PPS_n$	$\forall n,t$	(A20)
$stp_{nt} \le TPS_n \cdot PPS_n$	$\forall n; t \in \{1, T+1\}$	(A21)
$DMIN_{njt} \le d_{njt} \le DMAX_{njt}$	$\forall n,j,t$ [4]	(A22)
$dacc_{njt} \le TACC_{nj} \cdot ACC_{nj}$	$\forall n,j,t$	(A23)
$\sum_j shed_{njtsh} \le MAXSHED_{nsh} \cdot \sum_j dg_{njt}$	$\forall n,t,sh$	(A24)
$imp_{nkt} \le IMPMAX_{nkt}$	$\forall n,k,t$	(A25)
$exp_{nkt} \le EXPMAX_{nkt}$	$\forall n,k,t$	(A26)
$imp\_b_{nut} \le IMPMAX\_B_{nut}$	$\forall n,u,t$ [5,6]	(A27)

(A1) is the objective function, expressing maximization of social benefit. (A2) is the power balance equation. (A3), (A4) and (A5) describe a very simple version of a linearized generation cost curve, implying maximum efficiency up to a point $PBEST_i$, and an area of reduced efficiency between $PBEST_i$ and $PMAX_i$. This is primarily aimed at the typical characteristics of Norwegian hydro plants. The resource use relation must be convex. For thermal plants $PBEST_i$=$PMAX_i$ could be used if appropriate. (A6) takes care of annual resource constraints. For hydro W_i is the annual inflow volume, for thermal plants W_i can be given by emission or fuel constraints. (A7) expresses a weak version of reserve requirements, implying that all available capacity can be use for reserve. (A8) gives the balance for pumped storage reservoirs. Pumping is multiplied with the efficiency of the pumping cycle, which means that more energy than generated must be used to refill the reservoir.

(A9), which is similar to (A8), describes accumulation of demand. In this case no efficiency loss is assumed, but a cost given by (A10), which depends on the difference between actual use of energy from the grid dg_{jt} and demand d_{jt}. As can be seen from (A9), these to quantities are equal if demand accumulation is zero. In (A10) "≥" is used instead of "=" to avoid negative costs (i.e. income) when storage is refilled. (A11) dictates that there shall not be net accumulation during the

[4] In the AMPL code, the parametric restrictions for demand is formulated somewhat differently. The full notation would, however, complicate the mathematical restriction unnecessary. The actual restrictions for demand can easily be restated according to the formulation in these bounds.

[5] There is not a corresponding bound for export to region countries. The reason is that the restriction on export to region countries is determined implicit by the restriction on import for the other country. If, for instance, Sweden only can import 3000 from Norway, we know by the equation for transmission between region countries that the export from Norway to Sweden only can be 3000/(1-LOSS). This amount includes transmission losses from Norway to Sweden. It is of course possible to include an additional bound on the export, but then either the implicit bound or the explicit bound on export must be incorrect unless they are identical.

[6] The AMPL code includes some additional equations for sum r, p and imp. But these equations are only bookkeeping and not part of the optimization problem.

simulation period. (A12) - (A15) calculate costs and benefit for generation, import and load shedding respectively.[7] (A16) dictates that the import for importing country must be equal to the export for the exporting country, adjusted for losses.

Furthermore, (A17) limits maximum generation capacity for endogenous technologies, while (A18) gives the generation for exogenous technologies. (A19) and (A20) limit generation and pumping from pumped storage. (A21) limits storage capacity, which is given by a number of hours. (A22) gives maximum demand, while (A23) limits demand accumulation. Finally, (A24) restrict the amount of load shedding for each penalty interval, while (A25) - (A27) restrict the trade.

When the data for various parameters are given in the data-files of the model, it is convenient to represent many of these periods more aggregated than the 2210 periods, e.g. based on seasons or parts of the day. Thus, two additional sets for periods are defined: SEASON and LPER. The elements in the set SEASON are “winter”, “late winter” and “rest”, while the elements in the set LPER is “day”, “night” and “weekend”. Thus, the input data, except the demand profiles which are given for all elements, is given for the matrix of elements in SEASONS and LPER, e.g. for (winter,day). The “winter” is from week 45 to week 52 plus week 1 to week 11. The “late winter” is from week 12 to week 18, while “summer” is from week 19 to week 44. The “day” is Monday-Friday from 07:00 to 22:59, the “night” is Monday-Thursday from 23:00 to 06:59, and the weekend is from Friday 23:00 to Monday 06:59.

[7] The net import cost in (A14) is caused by net import from countries in IMPSEG and not by countries in REG, where the latter set shows those countries we model the capacity balance for. As a consequence, there will not be double counting of losses even though losses are given both for import and export. The reason for this is that we want to make sure that it is uneconomical for Norway to import electricity from Sweden through Denmark if there is available capacity from Sweden to Norway.

APPENDIX B: PARAMETER VALUES BASELINE SCENARIO 2005

Generation

	Capacity MW	Variable Cost øre/kWh	Availability %			Max Annual Energy GWh
			WIN	LWIN	REST	
Norway						
Hydro	27657	4	0.89	0.80	0.95	119600
Wind	17	0.1	0.41	0.32	0.2	1000
Sweden						
Hydro	16239	4	0.86	0.86	0.95	66200
Nuclear	9436	5	0.94	0.90	0.63	63600
CHP	3448	23	0.54	0.54	0.27	[8]
Thermal	2915	40	0.54	0.54	0.54	[4]
Wind	293	0.1	0.24	0.18	0.17	[4]

Import/Export capacites (MW)[9]

From\to	Norge		Sverige		Denmark		Finland		Rest	
	Peak load[10]	Else	Peak load	Else	Peak load	Else	Peak load	Else	Peak load	Else
Norge	-	-	3000	3000	500	1000	100	100	-	-
Sverige	3100	3100	-	-	1210	2420	1600	1600	800	800
Danmark	500	1000	1000	2420	-	-	-	-	-	-
Finland	100	100	200	1600	-	-	-	-	-	-
Andre	-	-	300	800	-	-	-	-	-	-

Electricity prices (øre/kWh)

Country	win-day	lwin-day	else
Denmark	35	20	15
Finland	35	25	25
Rest	35	25	25

Total Reserve Requirements (MW)

Norway	1513
Sweden	1733

[8] Annual energy is only restricted by the capacity and the availability.
[9] We assume that these numbers are net of transmission losses. The capacity used for export in the exporting country can therefore be larger.
[10] Peak load is "Winter day" and "Late winter day".

Demand in a full 52 week year with normal temperatures (TWH/year)

	Norway			Sweden		
	2001	2005	Growth %	2001	2005	Growth %
General	84.20	87.86	1.07	112.10	112.50	0.09
Industry	32.97	34.30	0.99	36.11	37.61	1.02
Boilers	5.49	5.49	-	-	-	-
Pumping	0.87	0.87	-	-	-	-
Total	123.53	128.52	0.49	148.21	150.11	0.32

Load Shedding Penalty (øre/kWh)

	Day	Night	Weekend
level 1 (first 3%)	200	199	198
level 2 (next 3%)	210	209	208
level 3 (rest)	220	219	218

Other parametrers

1. DMIN, DMAX is set so that all demand is exogenous, and general demand follows pu-curve, industry and boilers have constant demand and pumping has constant demand during REST and zero consumption in other periods.
2. Parameters ACC, TACC and VCACC are all zero.
3. Parameter LOSS is 7% for all indexes.
4. PBEST is 0.85 for hydro and 1 for other technologies, RBEST is 1 while RMAX is 1.1 for hydro and 1 for other technologies.
5. PPS and TPS is zero, while ETAP is 0.8.
6. There is 2210 periods. The number of hours in each period is given by

Hours for each period-type

	DAY	NGT	WKD
WIN	1	8	56
LWIN	1	8	56
REST	4424	0	0

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