Hydro reservoir handling in Norway before and after deregulation

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ABSTRACT

The Norwegian Energy Act that came into force in 1991 deregulated the electricity market and removed the former obligation power companies had to supply electricity to the geographical area they were responsible for. Hence producers can supply electricity on the basis of profitability. In 2007 the Energy Act was evaluated by the Government. As a part of this, a study concerning hydro reservoir handling before and after deregulation was carried out by SINTEF. Public statistics show that average hydro reservoir levels measured in per cent of reservoir capacity have been reduced after 1990. We have used the power-market model EMPS1 (EFI’s Multi-area Power-market Simulator) to analyze if this reduction can be explained by natural variation in climatic variables or by structural changes that have occurred after 1990. Simulation results show that the reduced reservoir levels cannot be explained by natural variation in climatic variables. Structural changes such as increased transmission capacities can, however, explain some of the reduction. Our study does not indicate that the present reservoir handling gives reservoir levels that are too low. In this paper we also describe the stochastic dynamic optimization problem for long-term hydropower scheduling, and we explain how this problem actually is solved by the EMPS model.

1. Introduction

In Norway, electricity production has always been based on decentralized decisions. Contrary to the situation e.g. in the UK, a central unit for operational planning has never existed. Instead, publicly owned regional hydropower companies were responsible for supplying enough electricity to their concessionary area. Consumer prices for electricity were set annually mainly based on average costs, but there was a market for power exchange between producers. As a result of the Energy Act [1] that came into force in 1991, the Norwegian power market was one of the first in the world to be liberalized. The law removed the power companies’ former obligation to supply enough electricity. Instead, producers can supply electricity on the basis of profitability. Wholesale spot prices for electricity are calculated on the Nordic power exchange Nord Pool based on bids for demand and supply. Consumers can choose between different suppliers, which act on behalf of small consumers at the exchange.

An overview of deregulation in the OECD countries is given in [2]. For policy-markers it is important to study the effects of liberalization, which typically are expected to reduce costs and stimulate efficiency. The influence of electricity deregulation on the design, operation and management of power plants owned by strategic and non-strategic producers is studied in [3]. The paper also discusses the effect of deregulation on system security and stability, focusing mainly on state-of-the-art combined cycles. In Norway, almost all power production comes from hydropower. An analysis of the effects of deregulation on a hydro dominated system like the Brazilian system is given in [4]. This study concludes that it is almost impossible to establish a viable daily market in such a system, because spot prices will be close to zero most of the time, and extremely high otherwise. On the other hand [5] shows that a deregulated power market with a large share of hydro can function well even during inflow shortages. One important difference between these studies is that the Norwegian system is well connected to thermal power generation capacity in other countries.

In the present analysis focus is on the actual handling of the hydro reservoirs in Norway. These reservoirs can store approximately 70% of the normal annual inflow. The handling of the reservoirs is therefore of major importance and often discussed in the public,
especially in dry years where electricity prices are high. If they are operated less efficiently in a market-based system this may reduce
the benefits of deregulation. Hence this was one of four main topics
when the Government evaluated the Energy Act in 2007, and the
main findings from the subsequent study [6] are documented in this
Section 2. Reservoir levels 1980–2007
Paper. The objective of the study is to assess whether the handling of
the Norwegian hydro reservoirs have changed after 1990 and to
consider if changes can be explained by natural variation in inflow to
reservoirs or by structural changes in the power system after 1990. In
the study we used the EMPS model (EFF’s Multi-area Power-market
Simulator), to simulate the Nordic power market.

Previous descriptions of the EMPS model have focused mainly on
the overall framework and algorithms [7], mathematical solution
methods for such problems [8] and on use of results from the
long-term model in models for the medium and short term [9]. In
the present paper we elaborate on the optimization problem we try
to solve, such as the different elements in the objective function,
and we describe how this multidimensional problem is simplified
so it can be solved within an acceptable computational time.

In Section 2 we show the registered reservoir levels in Norway
for different years and on average for different periods. This analysis
shows that reservoir levels have been reduced after the 1990 Energy
Act came in force. In Section 3 we describe the planning problem for
long-term hydropower simulation in the EMPS model. In Section 4
we investigate possible reasons for the reduced reservoir levels
based on results from EMPS model simulations. We consider natural
variation in climatic variables, such as variation in inflow to the
reservoirs, and structural changes that have occurred in the power
system after 1990. The isolated effects of some of these changes are
analyzed for different cases. In a separate scenario we try to simulate
the combined effect of all structural changes, and we compare the
resulting change in simulated reservoir levels with observations.
Summary and conclusions are provided in Section 5.

2. Reservoir levels 1980–2007

This shows the reservoir levels for each week for all years in the
period 1980–2007. It is based on information provided by The
Norwegian Water Resources and Energy Directorate (NVE) and
Nord Pool. The figure shows the typical seasonal pattern for the use
of reservoirs. The filling season starts in the spring when the snow
melts and continues through the summer and autumn. However,
during the winter consumption increases since electricity is used
for space heating, and much of the precipitation comes as snow and

### Nomenclature

<table>
<thead>
<tr>
<th>Sets and indices</th>
<th></th>
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</thead>
<tbody>
<tr>
<td>$F$</td>
<td>Load segments within a week, $f \in F$</td>
</tr>
<tr>
<td>$I_j$</td>
<td>Thermal generation units, $i \in I_j$, $j \in J$</td>
</tr>
<tr>
<td>$J$</td>
<td>Areas in simulated system, $j \in J$</td>
</tr>
<tr>
<td>$K$</td>
<td>Areas outside the simulated system, $k \in K$</td>
</tr>
<tr>
<td>$L_j$</td>
<td>Demand reduction options, $m \in L_j$, $j \in J$</td>
</tr>
<tr>
<td>$R$</td>
<td>Curtailment classes, $r \in R$</td>
</tr>
<tr>
<td>$T$</td>
<td>Planning period, $t \in T = {t, t+1, \ldots, N}$</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Parameters</th>
<th></th>
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</thead>
<tbody>
<tr>
<td>$a_{jm}$</td>
<td>Losses in transmission from area $j$ to area $n$, $a_{jm} \in [0, 1]$, e.g. 0.02</td>
</tr>
<tr>
<td>$\beta_{jm}$</td>
<td>Monetary tariff for transmission from area $j$ to area $n$, (Euro/MWh)</td>
</tr>
<tr>
<td>$c_{cur}$</td>
<td>Curtailment costs, (Euro/MWh)</td>
</tr>
<tr>
<td>$c_{dem}$</td>
<td>Cost of reducing consumption/marginal utility, (Euro/MWh)</td>
</tr>
<tr>
<td>$c_{gen}$</td>
<td>Marginal generation costs, (Euro/MWh)</td>
</tr>
<tr>
<td>$d_f$</td>
<td>Number of hours per week in load segment $f$, $d_f \in {1, 2, \ldots, 168}$</td>
</tr>
<tr>
<td>$\delta$</td>
<td>Discount factor per year, $\delta \in [0, 1]$, e.g. 0.95</td>
</tr>
<tr>
<td>$N$</td>
<td>Last week in planning period, (Week number)</td>
</tr>
<tr>
<td>$P_{imp}^{f}$</td>
<td>Import price from external areas, (Euro/MWh)</td>
</tr>
<tr>
<td>$P_{exp}^{f}$</td>
<td>Export price to external areas, (Euro/MWh)</td>
</tr>
<tr>
<td>$t$</td>
<td>Initial week, (Week number)</td>
</tr>
<tr>
<td>$\bar{z}_{jt}$</td>
<td>Minimum storage, (MWh)</td>
</tr>
<tr>
<td>$\chi_{jt}$</td>
<td>Maximum storage, (MWh)</td>
</tr>
<tr>
<td>$\gamma_{j}^{gen}$</td>
<td>Capacity for thermal power generation, (MW)</td>
</tr>
<tr>
<td>$\gamma_{j}^{gen}$</td>
<td>Minimum thermal power generation, (MW)</td>
</tr>
<tr>
<td>$\gamma_{j}^{hyd}$</td>
<td>Hydropower generation capacity, (MW)</td>
</tr>
<tr>
<td>$\gamma_{j}^{hyd}$</td>
<td>Minimum thermal power generation, (MW)</td>
</tr>
<tr>
<td>$\gamma_{j}^{dem}$</td>
<td>Demand reduction potential, (MW)</td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
<tr>
<td>$y_{j}^{exp}$</td>
<td>Export capacity from area $n$ to area $j$, (MW)</td>
</tr>
<tr>
<td>$y_{j}^{imp}$</td>
<td>Import capacity to area $n$ from area $j$, (MW)</td>
</tr>
<tr>
<td>$y_{j}^{end}$</td>
<td>A vector of stored water in all areas passed on from week $t-1$ to week $t$ in area $j$, (MWh)</td>
</tr>
<tr>
<td>$y_{n}^{end}$</td>
<td>A vector of stored water in all areas at the end of the final period $N$, (MWh)</td>
</tr>
<tr>
<td>$y_{n}^{dem}$</td>
<td>Demand reduction, (MW)</td>
</tr>
<tr>
<td>$y_{n}^{gen}$</td>
<td>Thermal power generation, (MW)</td>
</tr>
<tr>
<td>$y_{n}^{hyd}$</td>
<td>Hydropower generation, (MW)</td>
</tr>
<tr>
<td>$y_{n}^{cur}$</td>
<td>Curtained amount, (MW)</td>
</tr>
<tr>
<td>$y_{n}^{exp}$</td>
<td>Electricity export from area $j$ to area $n$, (MW)</td>
</tr>
<tr>
<td>$y_{n}^{import}$</td>
<td>Electricity import to area $j$ from area $n$, (MW)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Stochastic variables</th>
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<tbody>
<tr>
<td>$\bar{D}_{jt}$</td>
<td>Electricity demand with temperature dependency, (MW)</td>
</tr>
<tr>
<td>$\bar{y}_{j}^{wind}$</td>
<td>Wind-power generation, (MW)</td>
</tr>
<tr>
<td>$\bar{y}_{j}^{con}$</td>
<td>Controlled inflow to reservoir, (MWh)</td>
</tr>
<tr>
<td>$\bar{y}_{j}^{inc}$</td>
<td>Uncontrolled (non-storable) inflow to plant, (MWh)</td>
</tr>
<tr>
<td>$\bar{y}_{j}^{f}$</td>
<td>A vector of all stochastic variables in all areas, (MWh/MWh)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Functions</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>$S(x_{N}^{end})$</td>
<td>End-value function for reservoir water, (Euro)</td>
</tr>
<tr>
<td>$V(\bar{x}<em>{f}, \bar{v}</em>{f})$</td>
<td>Present value of all system costs in planning period, (Euro)</td>
</tr>
</tbody>
</table>
stays in the mountains, thus decreasing inflow. Reservoir levels are therefore reduced during the winter. As seen from the figure there is, however, considerable variation in reservoir levels for different years, mainly because of varying weather conditions.

Fig. 2 shows the average reservoir levels in different weeks before liberalization (1980–1990) and after (1991–2006). The levels are lowest for the period after 1990 in all weeks. The average reduction is 4.6% points, and the average reduction at the end of the filling season is 7.4% points. This is a major finding. In the following we show results from a study where we have used the EMPS model to investigate if reduced reservoir levels can be explained either by natural variation in climatic variables or by structural changes in the power system after 1990. But first we provide a description of the model.

3. The EMPS model

3.1. A model for hydro-thermal power systems

The EMPS model calculates the cost minimizing operation of a hydro-thermal power system such as the Nordic system. Optimization models are often used to analyze liberalized power markets even though the actual markets are not perfect, see e.g. [10] for a discussion, and many large power producers in the Nordic power market use the EMPS model for long-term hydropower scheduling (e.g. calculating strategies for use of reservoirs). The model is also commonly used for general power system studies such as the present study. The power system under consideration is divided into a number of interconnected areas, and area boundaries are mostly set on the basis of hydrological conditions and other properties of the hydropower system, bottlenecks in the transmission system and country borders. Fig. 3 illustrates the system that was simulated in the present study. All weeks and within-week load segments are simulated for a period of e.g. 5 years for all available climate scenarios.

The inputs to the model include costs and capacities for generation, transmission and consumption of electricity, information about climatic variables in the past, among other things. The description of the hydropower system within an area usually includes information of actual plants, reservoirs, waterways etc. The model calculates an optimal strategy for hydropower generation. For each area, week and stochastic scenario, the endogenous variables determined by the model during simulation include power prices, reservoir levels, electricity consumption and generation, and power exchange with other areas.

3.2. Aggregated strategy calculation and detailed simulation

The optimization problem is stochastic because of natural variation in climatic variables such as temperatures and inflow to reservoirs, and dynamic since the use of hydro reservoirs couple decisions in time. An application of stochastic dynamic programming called the water value method is used to solve the optimization problem in an iterative procedure described in (a)–(c) below.

(a) Strategy calculation

First, optimal strategies for hydropower scheduling are calculated for each area based on the described system, i.e. costs and capacities for generation, consumption, transmission etc. The probability distributions for stochastic variables in different weeks are calculated based on statistics for actual outcomes for these variables in the past. In order to reduce the computational time, all hydropower units within an area are aggregated to one equivalent power station with one equivalent reservoir, and water is measured in energy units. Still, the dimensionality of this optimization problem is so large that some additional
(b) Simulation as a part of strategy calculation

Second, the stochastic system is simulated with the optimal strategies for hydropower for all years where the needed information about stochastic variables are available, e.g. 1931–2005. This simulation uses the same aggregated representation of hydropower generation as the strategy calculation. Two different simulation types can be carried out. The first alternative is to simulate from a given week where reservoir levels are known, and in this case reservoir levels in the beginning of the first simulated week are set in accordance with observations (or assumptions in case of hypothetical studies). If a 5-year period is simulated, the first stochastic scenario is typically 1931–1935, the second is 1932–1936 etc. The second alternative is to simulate a given future period, e.g. year 2015. In this case the user sets reservoir levels for each area to be used in the beginning of the first simulated week, e.g. week 1 in 1931. The system is then simulated with calculated strategies from (a) and stochastic variables for year 1931. Next, the second year 1932 is simulated, and reservoir levels in the beginning of the first week are set equal to simulated levels at the end of 1931, etc. When all stochastic scenarios have been simulated, the strategy calculation in (a) is adjusted based on simulation results in an iterative process that continues until a convergence criterion is met.

(c) Final detailed simulation

Finally the simulated hydropower generation per aggregated area is allocated to the actual hydropower plants in the modeled system. A rule-based method that on the whole corresponds to how reservoirs traditionally have been utilized to deal with the seasonal profile for inflow and demand is applied. For example, during the wet season minimizing overflow is an important consideration. The detailed simulations account for many actual physical constraints in specific hydropower plants, varying efficiency for generators at different production levels, and hydraulic couplings in waterways among other things. If the calculated hydropower generation for a specific area in the aggregated model is unattainable in the detailed simulation, the total production for this area is adjusted.

3.3. The optimization problem for strategy calculation

In the following we describe the mathematical optimization problem for strategy calculation, cf. (a) in Section 3.2. The objective is to minimize the expected sum of all system costs from the initial week (t) to the finite planning horizon (N) in all modeled areas \( j \in J \).

Each week is divided into several load segments \( f \in \mathcal{F} \) where a segment represents a number of hours \( \Delta t \) within the week. The chronology within the week is not accounted for. The minimal cost is given by the value function \( V_t \) in Eq. (1). It is assumed that reservoir fillings passed on from the previous week \( \{x_t^f\} \) and all outcomes for stochastic variables in the present week \( \{v_t^f\} \) are known and therefore also arguments in the function in the present week \( \{t\} \). The Bellman formulation of the objective function is:

For thermal generation \( y_{t}^{\text{gen}} \), constant marginal costs \( c_{t}^{\text{gen}} \) that include all operating costs such as fuel costs, variable maintenance costs and possible costs of using CO2 permits are assumed. There may be a seasonal profile for production costs and for available capacity. For instance, some thermal power units have an obligation to produce heat in addition to electricity and this affects costs and capacities for electricity production.

The transmission between two areas \( j \) and \( n \) \( y_{j}^{\text{imp}} \) \( y_{n}^{\text{exp}} \) is restricted by the capacity of the transmission line \( y_{j}^{\text{imp}} \cdot y_{n}^{\text{exp}} \), which may not be the same in both directions.

A small share \( \alpha_{jn} \) of the transmitted energy is lost, cf. Eq. (6).

For import and export to areas on the outside of the simulated system there are exogenous prices \( p_{j}^{\text{imp}} \cdot r_{n}^{\text{exp}} \). It is also possible to model the price in an external area as a function of net import. Net
costs of trade with areas on the outside of the simulated system are included in the objective function.

For each area, week and load segment there must be a balance between demand and supply for any outcome of the stochastic variables, cf. Eq. 7. The dual value for one of these constraints (divided by the number of hours it represents) is the simulated power price.

\[
y_{\text{hyd}} + \sum_{i \in L_j} y_{\text{gen}} + y_{\text{wind}} = D_{ijt} - \sum_{r \in R} y_{\text{dem}} - \sum_{c \in (K \cup \{j\}) \setminus (L_j)} (y_{\text{exp}} - y_{\text{imp}}) \quad \forall j \in J, f \in F
\]

Demand and wind-power generation are affected by uncertain weather conditions such as temperatures and wind speeds. In the model they are stochastic variables as indicated by the "\(\sim\)" symbols in Eq. (7). In practice, wind-power is usually modeled as a correction to the demand or as separate hydropower areas with zero storage capacity. The demand has a within-week profile for load segments as well as a within-year profile for demand in different weeks. The annual temperature-adjusted demand may also increase from one year to the next. For each demand reduction option there is a constant marginal cost \((c_{\text{int}}^{\text{dem}})\), which represents the marginal value of consumption, and a capacity.

\[
y_{\text{dem}} \leq \gamma_{\text{dem}} \quad \forall f \in F, m \in L_j, j \in J
\]

Demand can also be specified as continuous variables. In this case the model generates a step-wise approximation to the continuous curve. This is mostly used for general demand. For those rare cases where a balance between demand and supply is unattainable given the specified flexibility for demand and supply, it is assumed that the balance is achieved through controlled curtailment \((c_{\text{cur}}^{\text{dem}})\) at high socio-economic costs per MWh \((c_{\text{cur}}^{\text{dem}})\). The curtailment cost per MWh can be implemented as an increasing function of the curtailed amount, and in this case there is a maximum capacity for each curtailment level. In practice the most expensive curtailment option can be used as much as needed.

\[
y_{\text{cur}} \leq \gamma_{\text{cur}} \quad \forall r \in R, f \in F, j \in J
\]

For market simulations the curtailment costs represent the producer price expected to be set by the government in cases where the market is out of operation for instance because no market equilibrium exists at the power pool or because the equilibrium price is unacceptable. The curtailment costs may therefore deviate from the actual loss in consumers’ utility if they are curtailed.

The amount of water available in the present week is the amount passed on from the previous week \(x_{j\tau}\) plus stochastic inflow to reservoirs in the present week \(s_{j\tau}^{1}\) plus non-storable inflow that goes directly to the plant \(s_{j\tau}^{2}\). For hydropower generation the most important decision is to determine the amount of water to be released from reservoirs \(u_{j\tau}\). This decision determines the amount of water passed on to the next week \(x_{j+1\tau}\) as well as the generation in load segments within the present week \(y_{j\tau}^{\text{hyd}}\)

\[
x_{j+1\tau} = x_{j\tau} + s_{j\tau}^{1} - \sum_{f \in F} \Delta t_{j\tau} y_{j\tau}^{\text{hyd}} \quad \forall j \in J
\]

\[
y_{j\tau}^{\text{hyd}} = u_{j\tau} + s_{j\tau}^{2} - s_{j\tau}^{1} \quad \forall j \in J, f \in F
\]

The amount of water that can be passed on to the next week is constrained by the storage capacity in reservoirs and by possible regulations for the minimum amounts of water that must be stored.

\[
x_{j\tau+1} \leq x_{j\tau+1} \leq x_{j\tau+1} \quad \forall j \in J
\]

Water may be lost because of overflow from the reservoir \(s_{j\tau}^{2}\) when the reservoir is full (this water does not go to the power station), and because of bypass discharge \(s_{j\tau}^{2}\) when the amount of water that comes to the station is larger than the generating capacity \(y_{j\tau}^{\text{dem}}\). Because of environmental concerns there may also be minimum restrictions on the discharge i.e. on the minimum amount that must be produced \(y_{j\tau}^{\text{hyd}}\).

\[
y_{j\tau}^{\text{dem}} \leq y_{j\tau} \leq y_{j\tau}^{\text{hyd}} \quad \forall j \in J, f \in F
\]

3.4. End-value function

In reality, hydropower scheduling is an optimization problem with an infinite or unknown horizon. In our finite horizon model it is therefore necessary to set a value on stored water at the end of the final week given by the \(S(\cdot)\) function in Eq. (1). Otherwise reservoirs would be emptied towards the end of the planning period in simulations. The end-value function for water is calculated by repeating the final year so many times that the used end-value function has no influence on the values of passing water to week \(N\), and these resulting values are used. In other words, the final year is assumed to represent an infinite future.

3.5. Water value method

A variant of the water value method, which is an application of stochastic dynamic programming, is used to solve the model. See e.g. [11] for an early reference to stochastic dynamic programming (SDP) and [12–14] for early references to the water value method. Here we only give a brief sketch of how such problems can be solved.

The availability of water in future weeks is reduced if extra water is used in the present week. The income from use of reservoir water in hydropower production in the present week must therefore be balanced against lost income in the future, and the size of this loss is uncertain. We must therefore derive the expected marginal value of passing more water to the next week before we can find the optimal release for the present week, cf. the Bellman formulation of the objective function in Eq. (2). The optimal strategy for hydropower generation can in principle be solved step by step starting in the final period \(N\) where there by assumption is uncertainty left. When the optimal strategy (generation, reservoir release etc) has been calculated for the final period for different reservoir fillings passed on from period \(N-1\) and for different stochastic outcomes for period \(N\), it is possible to calculate the expected value of passing additional water to the final period. Hence it is also possible to derive the optimal strategy for week \(N-1\) for different reservoir fillings passed on from period \(N-2\) and for different stochastic outcomes in period \(N-1\). The expected marginal value of passing more water from week \(N-2\) can therefore be calculated, etc. The final result of the strategy calculation is a water value table for each area that shows the expected marginal value of passing more water to different weeks for different reservoir levels. These water values are used as marginal production costs for hydropower generation during simulations.

In theory, the value of stored water in one area will be a function \(\bar{V}(\cdot)\) and of the full vector of the outcomes for stochastic variables in the present period \(\vec{\eta}\), cf. Eq. (1). The dimensionality of this optimization problem is, however, too large to be solved with SDP with acceptable computational times. Therefore, the water values are in practice calculated for each area in isolation. A share of the residual demand to be covered by hydropower, which is a function of price, is assigned to each hydropower area based on some calibration factors
that may be tuned by the user or automatically based on results from the detailed simulations (e.g. average socio-economic surplus or simulated reservoir levels). When strategies have been calculated the whole interconnected system is simulated for all available climatic years using optimal strategies for hydropower, and with demand and supply allocated to their respective regions.

4. Power-market simulations

4.1. Simulated cases

We have used the EMPS model to investigate possible causes for the reduced reservoir levels after 1990. The effects of climatic variation and the most important structural changes that have occurred are studied in different cases. We have also included a case where all major assumptions are set in accordance to the situation before deregulation. The motivation for this is to find out if the model’s ability to explain reservoir levels has changed after deregulation. The system planning that was carried out before deregulation, basically minimization of system costs, shall in principle give the same outcome as a competitive market. However, if there is a major difference in the model’s ability to explain reservoir levels before and after deregulation, this is an indication that the deregulation itself has affected the operation of reservoirs.

Table 1 gives an overview of all simulated cases and the resulting average reservoir levels for each case. Case 1 is the reference case where input data in general are set in accordance with the power system as it existed in 2005. In Case 2 we analyze if the reduced reservoir levels before and after deregulation, this is an indication that the deregulation itself has affected the operation of reservoirs.

Table 1
Simulated cases: description and average reservoir levels in simulations.a

<table>
<thead>
<tr>
<th>Case</th>
<th>Average reservoir levels</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Reference case</td>
<td>Input data are set in accordance to the situation in 2005. 56.2%</td>
</tr>
<tr>
<td>Simulated period</td>
<td>1980–1990 Observed 1980 60.9%</td>
</tr>
<tr>
<td></td>
<td>1991–1998 Observed 1991 58.9%</td>
</tr>
<tr>
<td></td>
<td>1990–2005 Observed 1999 62.7%</td>
</tr>
<tr>
<td>3. Curtailment cost</td>
<td>Curtailment costs are reduced from 37.5 to 8.75 Eurocents/kWh. 52.8%</td>
</tr>
<tr>
<td>4. Transmission capacity</td>
<td>Transmission capacities from 1990 are used. 58.7%</td>
</tr>
<tr>
<td>5. Power balance</td>
<td>The Norwegian power balance is adjusted to the situation in 1990. 53.4%</td>
</tr>
<tr>
<td>6. Climatic years 1931–1980</td>
<td>Water values are calculated based on statistics available in 1990. 58.8%</td>
</tr>
<tr>
<td>7. Climatic years 1970–2005</td>
<td>Water values are calculated based on statistics for the years after 1970. 48.4%</td>
</tr>
<tr>
<td>8. Case 1990</td>
<td>Several structural changes between 1990 and 2005 are accounted for. 59.9%</td>
</tr>
<tr>
<td>Simulated period</td>
<td>1980–1990 Observed 1980 64.9%</td>
</tr>
<tr>
<td></td>
<td>1991–1998 Observed 1991 62.5%</td>
</tr>
<tr>
<td></td>
<td>1990–2005 Observed 1999 66.3%</td>
</tr>
</tbody>
</table>


Cases 3–7. We consider changes in curtailment costs, transmission capacities, power balance, available statistics for stochastic variables and climate change. Finally, in Case 8 and 9 we study how reservoir levels change compared to the reference case if input data is set in accordance with the power system that existed in 1990. In these cases we include, among other things, partial structural changes that are studied in the previous cases.

For each case the model produces results for water values, prices, generation from different units, demand, transmission, water values etc for each area and simulated week, in addition to the operation of each hydro plant and reservoir. In the following we will present simulation results only for reservoir levels since this has been the focus in this particular study.

4.2. Reference case assumptions (Case 1)

Input data are in general set in accordance with the power system that existed in 2005, and based on the dataset used in [15]. The simulated system is illustrated in Fig. 3. Transmission capacities are based on information from Nordel (collaboration organization of Nordic TSOs). See also Table 2.

The production capacity used in simulations is set in accordance with the installed capacity at the beginning of 2005, cf. [16]. Inflow series for different regions in Norway in the period 1931–2005 were provided by NVE. Many specific thermal power production units are modeled for the Nordic system, and the marginal cost for the different units is a major uncertainty in the used input data. We have scaled previously used production cost data to account for price increases for fossil fuels. Marginal costs do not include costs of using CO2 allowances (the European market for CO2 allowances started in 2005). In 2005 most wind-power plants in the Nordic region were located in Denmark. For each year in the period 1961–1990 the annual and within-year variation per week is calculated based on observations [15], while monthly registrations [17] are used for the period after 2000. For other years average profiles are used. Actual generation in different years is scaled to account for the increase in installed capacity up to 2005.

The consumed amount of electrical energy is an output from the EMPS model. We have, however, tuned the demand so that simulated consumption on average is approximately equal to temperature corrected consumption registered for 2005. The temperature corrected gross demand in 2005 was 148.8 TWh for Sweden, 36.0 TWh for Denmark and 85.8 TWh for Finland [16]. For Norway we calculated the temperature-adjusted gross demand for 2004 to 123.9 TWh based on [18] and [19].

In simulations, general demand is affected by observed weekly temperatures and calculated temperature sensitivity. For Norway there is also price-flexibility for general demand. At high prices the demand is reduced by 7%, which is the same share as Nordel use in their calculations. For Norwegian manufacturing industry the production capacity used in simulations is set in accordance with the installed capacity at the beginning of 2005, and based on the dataset used in [15]. The simulated system is illustrated in Fig. 3. Transmission capacities are based on information from Nordel (collaboration organization of Nordic TSOs). See also Table 2.

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demand is assumed to be 34.7 TWh at low prices, but demand is reduced successively by 11.7 TWh at prices between 3.88 Eurocents/kWh and 12.5 Eurocents/kWh. For Sweden, Denmark and Finland the consumption in manufacturing industry is a part of general demand in our dataset. The demand from dual-fuelled electrical boilers responds to prices in all countries.

Import prices from Poland and Germany are set to 4.03, 2.74 and 2.46 Eurocents/kWh, respectively for day, night and week-end, while export prices are set to 3.45, 2.16 and 1.88. It is assumed that Finland imports 10.5 TWh from Russia each year, independent of prices. In the optimization we used the real interest rate of 2.15% which was the interest rate for a 10-years government bond in 2005 (3.75%) minus the Norwegian inflation rate for that year (1.6%). The resulting annual average for reservoir levels in Norway is 56.2% in the reference case, cf. Table 1. This is a weighted average for all Norwegian areas in 75 simulated climatic years (1931–2005) and 52 weeks per year.

4.3. Analyzing 1980–2005 using reference case strategies (Case 2)

Natural variation in climatic variables, especially inflow to reservoirs, affects reservoir levels. In the following we will use the EMPS model to estimate how this variability has affected reservoir levels for different years in the period 1980–2005.

Using the calculated strategy for the reference case (water values for different filling degrees in different weeks and areas), the Nordic power system was simulated week by week for the period 1980–2005 using observed values for climatic variables in each week. We used the registered reservoir levels in the beginning of week 1 for the years 1980, 1991 and 1999. This is done to prevent possible divergence between simulations and registrations in past years from having too much influence on the correspondence between simulations and registrations e.g. for the period after 1990.

Simulated and registered reservoir levels for Norway for the period 1999–2005 are shown in Fig. 4. The correspondence between simulations and registrations was better for this period than for 1980–1990 and 1991–1998, where the simulated reservoir level typically was lower than the registered. The average simulated reservoir levels for different weeks in each period are shown in Fig. 5. This figure shows those differences in reservoir levels that can be explained by variations in climatic variables. In most weeks the average reservoir level for the first period (1980–1990) is between the average levels for the two more recent periods. The reduced reservoir levels registered after 1990 can therefore not be explained by the variation in climatic variables. Fig. 6 shows the registered reservoir levels for the three periods, adjusted for differences in simulated levels using the first period (1980–1990) as the basis for adjustment. The effect of natural variation in climatic variables on reservoir levels has therefore been filtered out, and the remaining difference must be explained by other factors. In this figure, the average reservoir level is highest for the period before the 1990 Energy Act came into force and lowest for the most recent period. This shows that the reservoir handling has changed after 1990. In the rest of the paper we will investigate possible reasons for this change.

4.4. Curtailment costs (Case 3)

For the reference case input data are set in accordance with the power system that existed in 2005. In the following we will investigate whether structural changes that occurred between 1990 and 2005 can explain reduced reservoir levels. First we consider the curtailment price.

Curtailment may occur also after deregulation, especially in a hydropower dominated system with stochastic inflow to reservoirs. Because of unwanted distributional consequences of extreme electricity prices, it is expected that the regulator at some point will intervene in a critical situation. But the producer price for electricity during curtailment is unknown. If the expected price during curtailment, which is represented in the model, is below the real socio-economic curtailment cost, the outcome in a generally well-functioning market will not be fully efficient.
In the reference case we used the curtailment price 37.5 Eurocents/kWh. In the first years after the Energy Act came into force many producers used the curtailment price 8.75 Eurocents/kWh in their planning. This price was approximately equal to the marginal costs for the most expensive thermal power generation in the Nordic countries. In Case 3 we reduce the curtailment price from 37.5 to 8.75 Eurocents/kWh. As a consequence, the emphasis on avoiding curtailment is reduced relatively to the emphasis on avoiding flooding from reservoirs. Simulated reservoir levels decrease by 3.4% points on average compared to the reference case, cf. Table 1.

4.5. Transmission capacities (Case 4)

The transmission capacities between Nordic countries and between the Nordic region and other countries have increased between 1990 and 2005. The isolated effect of using the transmission capacities from 1990 instead of the capacities from 2005 is studied in Case 4. The assumed changes from 1990 to 2005 are shown in Table 2 and they are based on [16] for years 1989, 1991 and 2005. In the reference case it was assumed that Finland imported 10.5 TWh each year from Russia. The transmission capacity between these countries has increased from 1000 MW in 1991 to 1560 MW in 2005. In Case 4 we assume that the net import to Finland is 7.5 TWh each year.

The reduced transmission capacity in Case 4 compared to the reference case gives reduced import potential in dry years, and the probability for expensive curtailment increases. Hence more water is stored to reduce the curtailment in dry years, even though this gives additional flooding from reservoirs in wet years. The simulated reservoir levels increase by 2.5% points on average compared to the reference case, cf. Table 1.

4.6. Electric power balance (Case 5)

The balance between domestic demand and supply has changed considerably after 1990. According to [20] Norway would export 0.8 TWh in an average year in 1990. In 2005 the temperature-adjusted consumption was 129.6 TWh, hydropower production for a normal year was 119.7 TWh [19] and thermal power production was approximately 1 TWh. The normal year domestic balance has therefore changed with approximately 10 TWh after 1990. In Case 5 we study how this affects the use of reservoirs. It would be demanding to adjust our data for all changes that have occurred for specific generating units and demand since 1990. Instead we reduce general demand by 10 TWh compared to the reference case, distributed proportionally to Norwegian areas. This negative shift in demand gives reduced power prices, which in turn gives increased demand. As a consequence, the simulated reduction in consumption is only 8.3 TWh on average. The improved domestic balance in Case 5 makes it easier to handle dry years without curtailment, while the danger for reservoir overflow in wet years increases. This is reflected in the strategies for handling of reservoirs, and, as a consequence, average reservoir levels are reduced by 2.8% points compared to the reference case, cf. Table 1.

4.7. Climatic years 1931–1980 (Case 6)

In 1990 inflow series for hydropower were available only for the period 1931–1980 for most parties. Today, inflow series up to at least 2005 are available. The length of inflow series has therefore increased with 25 years or more since 1990. This affects the use of reservoirs since the average inflow to reservoirs has increased after 1980. The average hydropower production is 5.2 TWh higher for the period 1981–2005 than for 1931–2005 in the reference case. In Case 6 we study the isolated effect of using inflow series and other stochastic variables for the period 1931–1980 in strategy calculation. The whole period 1931–2005 is however, simulated after strategies have been calculated. The new strategies reflect the increased probability of relatively dry years and the reduced probability of relatively wet years compared to the reference case. As a consequence, more water is held back in reservoirs. The simulated average reservoir levels are increased by 2.5% points on average, cf. Table 1.


There is a growing awareness of the existence of climatic changes, and it is possible that some producers only use the most recent parts of the statistics in their operational planning. In Case 7 we investigate how the simulated reservoir levels change if water values are calculated based on statistics for the years 1970–2005. The average hydropower production is 3.2 TWh higher for the period 1970–2005 than for 1931–2005 in the reference case. The new strategies reflect the reduced probability of relatively dry years and the increased probability of relatively wet years. As a consequence, less water is held back in reservoirs. The simulated reservoir levels are reduced by 7.8% points on average compared to the reference case, cf. Table 1.

4.9. Case 1990 (Case 8)

Previous cases illustrate isolated effects of specific changes in the period 1990–2005 and uncertain factors. In Case 1990 we analyze the net effect of several changes that have occurred since 1990. In the following we will describe the major assumptions for Case 1990.

(a) Inflexible demand

A power market existed in Norway also before 1990, but this was mainly a market for trade between producers. Consumer prices were set mainly on basis of average costs and they were not affected by the short run market price. In Case 1990 we remove the price-flexibility that was used for general demand and industry in the reference case. For electrical boilers we use the same price-flexibility in both cases.

(b) Curtailment cost

Before the Energy Act came into force, power companies were supposed to use a specific curtailment cost function for possible deficiencies in their deliveries of so-called firm power. These costs were supposed to be used in the operational planning, but neither producers nor consumers had to pay these prices in case of curtailment. In Case 1990 we use the curtailment cost function that was specified for the period 1st May 1990–30th April 1991 [20], cf. Table 3. Electrical boilers respond to power prices in our simulations and they are not curtailed. In the reference case the curtailment cost was set to 37.5 Eurocents/kWh.

Table 3

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<thead>
<tr>
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<tbody>
<tr>
<td>Firm power (shares)</td>
<td>Curtailment cost (Eurocents/kWh)</td>
</tr>
<tr>
<td>0–10%</td>
<td>8.625–11.5</td>
</tr>
<tr>
<td>10–25%</td>
<td>11.5–57.75</td>
</tr>
<tr>
<td>25–100%</td>
<td>57.75</td>
</tr>
<tr>
<td>Dual-fuelled electrical boilers</td>
<td></td>
</tr>
<tr>
<td>Heavy oil</td>
<td>2.13</td>
</tr>
<tr>
<td>Light oil</td>
<td>3.08</td>
</tr>
</tbody>
</table>

* We have used the exchange rate 8 NOK per Euro.
(c) Transmission capacity
For Case 1990 we apply the exchange capacities that existed between Nordic countries and between the Nordic countries and other countries in 1990, cf. Case 4.

(d) Power balance
General demand is reduced by 10 TWh compared to the reference case, and this is distributed proportionally to different areas, cf. Case 5.

(e) Climatic years used in water value calculation
In the water value calculation for Case 1990 we use the inflow series that were available for most parties in 1990, i.e. 1931–1980, cf. Case 6.

For Case 1990, simulated reservoir levels are on average reduced by 3.7% points compared to the reference case, cf. Table 1. This indicates that a share of the observed 4.6% point reduction in reservoir levels after 1990 can be explained by structural changes that have occurred in the power system. This is investigated further in the next case by simulating each year in the period 1980–2005 using Case 1990 strategies.

4.10. Analyzing 1980–2005 using Case 1990 strategies (Case 9)
In Case 9, each year in the period 1980–2005 is simulated using observed values for climatic variables in each week and strategies for Case 1990. See Case 2 for more details. Fig. 7 shows annual average values for reservoir levels in Norway for each period 1980–1990, 1991–1998 and 1999–2005 from public statistics, for Case 2 (reference case strategies) and for Case 9 (Case 1990 strategies). For the period 1999–2005 the average reservoir levels for Case 2 (reference case strategies) is 0.3% points below the registered reservoir levels. For the period 1980–1990 simulated reservoir levels for the same case are 6.6% points below the registered levels. However, a share of this difference can be explained by the structural changes that have occurred after 1990 since average reservoir levels for Case 9 (Case 1990 strategies) are 4% points higher than for the reference case for this period (1980–1990).

5. Conclusions
Average reservoir levels have been reduced by 4.6% points in Norway after the Energy Act came into force. Simulations with the EMPS model show that this reduction cannot be explained by natural variation in inflow to reservoirs or other climatic variables. On the other hand simulations show that a share of the reduction in reservoir levels can be explained by structural changes that have occurred after 1990, such as increased transmission capacity, market-based consumer prices and availability of a longer statistical series for inflow to reservoirs.

Before deregulation, power companies had a formal responsibility for electricity supply in their region. It is therefore possible that they used hydro reservoirs more cautiously than implied by strategies calculated by the EMPS model, even though curtailment prices are reflected by strategies. Some power producers are concerned about the energy situation in their region also after deregulation. But it is reasonable to assume that they had a stronger focus on this before the Energy Act removed their formal responsibility.

In the latest period in the study, 1999–2005, there is a good correspondence between the registered and simulated reservoir levels. Consequently, our study does not indicate that present handling of reservoirs results in reservoir levels below socioeconomic optimal levels. The correspondence between observations and model simulations, where the latter is a result of system optimization, is better for the latest period than for the period before liberalization when using respective system descriptions for the two periods, cf. Fig. 7. While the registered reservoir filling is only 0.3% points above the simulated values for the latest period, the difference is 2.6% points for the period before liberalization. This indicates that structural changes and liberalization are approximately equally important for the observed reduction in reservoir levels.

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