Technical University of Denmark

WP7 Case analysis of operational management of grids
SUPWIND Deliverable D 7.1

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SUPWIND Deliverable D 7.1
WP7 Case analysis of operational management of grids

Report on Findings of Working Package 7

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Abstract:

This deliverable is part of a series of working documents within the project *Decision Support for Large Scale Integration of Wind Power SUPWIND*, supported by European Commission within the 6th FP under Contract No. TREN/05/FP6EN/S07.61830/020158 SUPWIND. This report documents the development and findings in WP 7 of the SUPWIND project.

Considering operational management of grids, the aim of Supwind WP7 is to analyze a selected case in close collaboration between model developers and a transmission system operator (TSO). The case serves to examine the ability of the modeling tools to assist in day-to-day operation and planning of the TSO. Special emphasis is placed on day-ahead scheduling, including the estimation of power reserves ahead of an operation day. To fully illustrate the nature of day-to-day planning, the tools are run with data that represented the latest information while operating (online data). The case is based on the Danish power system.

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1 Day-to-day operational management: A Danish case study

Considering a real case study on the Danish power system, the present chapter aims to illustrate the collaboration between model developers and the transmission system operator (TSO) in day-to-day planning. In particular, the idea is to analyse the ability of the modelling tools to assist the TSO in operating the system ahead of operation, referred to as day-ahead planning.

1.1 The modelling tools

The modelling tools of the SUPWIND project comprise the Scheduling Model and the Scenario Tree Tool [Barth et al. 2006, Meibom et al. 2006, Meibom et al. 2007].

The Scheduling Model is a mixed-integer multi-stage stochastic programming model [Birge and Louveaux 1997] for planning unit commitment and dispatch under uncertainty in a liberalized power system integrating wind power. The transmission system is captured by the use of a multi-regional model. Since used for short-term planning, it has an hourly time resolution and a time horizon that includes at most the current and the following operation day. The model takes into account the market equilibria in a day-ahead market, an intra-day market and other markets, e.g. a reserve market. The day-ahead market facilitates the physical delivery of power for the following day, taking into account scheduled outages and the expected load and wind power given by *forecasts*. In contrast, the intra-day market handles forced outages and imbalances between expected and realised load and wind power caused by *forecast errors*. Basically, scheduling decisions divide into stages according to the information flow such that day-ahead decisions are first-stage and intra-day decisions relate to the remaining stages.

Uncertainty of forced outages and load and wind power forecast errors are represented by stochastic parameters in the stochastic programming model. The Scenario Tree Tool serves to generate a discrete distribution of the parameters that complies with the flow of information, i.e., a scenario tree. Drawing samples from a statistical model, clustering simultaneously reduces the sample size and induces a tree structure.

The modelling tools of SUPWIND have been adapted to the Danish case study as an attempt to reflect reality as closely as possible.

The Scenario Tree Tool

Where possible, the Scenario Tree Tool, cf. [Barth et al. 2006] has been updated to comply with the forecast and the forecast accuracy of the Danish TSO. The changes required follow below.

To accommodate day-ahead planning, the Scenario Tree Tool works with a forecast horizon up to 36 hours, i.e. from 12:00 the current day to 00:00 the following day.

As wind speed forecast errors are not as difficult to model than wind power forecast errors, wind power is transformed to wind speeds by the use of a multi-turbine power curve that represents all wind turbines in a region and accounts for the installed wind capacity, the size of the region and the distribution of wind within the region, including the propagation of wind and the smoothing effect between turbines, cf. [Norgard and Holtinnen 2004, Norgard et al. 2004]. Due to the non-linearity of the power curve, realised and forecasted wind power has been transformed to realised and forecasted wind speeds before wind speed forecast errors has been derived. The forecast errors are used to estimate a statistical model from which simulation is possible. Having simulated a set of scenarios for wind speed forecast errors, scenarios for wind power forecast errors are obtained by a reverse power curve transformation.

Wind speed forecast errors are simulated by sampling from a statistical model able to capture autocorrelations of the errors over the forecast horizon and correlations between errors at different measurements stations, cf.

[Söder 2004]. The stochastic process of wind speed forecast errors at station is modelled as an ARMA(1,1) process such that

$X(k) = \alpha X(k-1) + Z(k-1) + \beta Z(k),\ k \in N$

where X(k) denote the wind speed forecast error in hour k, Z(k) is a Gaussian random variable with mean value zero and standard deviation σ_Z in hour k and α and β are parameters. The parameters have been re-estimated to reflect the real forecast accuracy of the Danish TSO by minimizing the square error between empirical standard deviations and those of an ARMA(1,1) process. Simulation has been done by means of Monte Carlo sampling. Correlations between errors are assumed instantaneous and have been obtained during sampling by Cholesky decomposition of the correlation matrix. The result is a number of sample paths, also referred to as scenarios. As real forecast errors usually have a mean value different from zero, a single draw has been added to every scenario. This single draw consists of forecast errors from the Danish TSO which at the same time ensures a mean value of the forecast scenarios equal to the real forecast of the Danish TSO. Load forecast errors are simulated in the same way as wind speed forecast errors, assuming load and wind power are independent.

By clustering the scenarios, cf. [Dupacova et al. 2000, Gröwe-Kuska et al. 2003], the distribution of forecast errors can be described by a scenario tree. Assuming new information arrives only every 6 hours, the duration of the stages of the scenario tree should be 6 hours. Using a three-stage scenario tree as an approximation, the first and the second stages have duration of 6 hours while the third stage occupies the remainder of the time horizon. The forecasts are used in all three stages although these could have been replaced by realised values to obtain a deterministic first stage. For the purpose of day-ahead planning, the difference is small since the first stage serves only to compute the state of the system prior to planning.

Forced outages of the units are described by a Semi Markov process with two states; available and unavailable and corresponding transition rates; the probabilities of being available and unavailable, cf. [Endrenyi 1978, Anderson and Davidson 2005]. The Semi Markov process has the property that the time spent in a state depends on the current state of the process but not on previous states. Being available/unavailable, the time spent is randomly generated from at Weibull distribution with a scale factor equal to the mean time to failure/repair. It is assumed that the states of different units are independent. The estimation of probabilities and scale factors requires a forced outages rate and a mean time to repair, either derived from empirical observations or based on subjective judgements at the Danish TSO. The Semi Markov process has been used for sampling, incorporating updated scheduled outages such that these apply to units not subjected to forced outages.

The Scheduling Model

Recall that the Scheduling Model is a mixed-integer linear programming model for unit commitment and dispatch. Since the scheduling of the Danish units are of main interest, as the data quality of the larger units are superior and finally to improve solution times, only major Danish units are modelled using mixed-integer programming. The remaining units are handled by linear programming as concerns start-up costs, minimum up- and down times etc.

Likewise, the most important regions being the Danish, Denmark faces a forecast in the day-ahead market and a scenario tree of forecast errors in the intra-day market. Since wind power uncertainty is the most significant source of uncertainty in the Danish system, being less predictable than load, wind power forecast errors are represented as stochastic parameters whereas load forecast errors are deterministic. For computational reasons and due to data requirements, the remaining countries are assumed to have a perfect forecast.

When the Scheduling Model is to be used in day-to-day planning, information will occasionally be updated and the model is therefore rerun, referred to as rolling planning. For every rerun or loop, the state of the system at the previous run is taken as starting conditions and unit outages, wind power forecasts and load forecasts are updated. Assuming a 5 hour delay of forecasts between the Danish weather service and Energinet.dk (in reality the delays are varying), wind power forecasts become available at 00:00, 06:00, 12:00 and 18:00 and load forecasts at 12:00. With this update of information, the model is rerun at 00:00, 06:00, 12:00 and 18:00. The

12:00 loop takes care of day-ahead scheduling according to the forecasts and the forecast errors. The real wind power forecast applies from 12:00 the current operation day to 0:00 the following operation day. However, the load forecast used consists of two real load forecasts, from 12:00 to 0:00 and from 0:00 to 0:00. The use of fundamental models for load forecasting at the Danish weather service implies constant forecast accuracy and justifies this. The day-ahead scheduling is done such as to facilitate intra-day rescheduling of the following day in response stochastic wind power forecast errors and deterministic load forecast errors. Apart from day-ahead scheduling for the following day, the 12:00 loop handles intra-day rescheduling for the current day. The intra-day rescheduling also applies to the 00:00, 06:00 and 18:00 loops, considering forecast errors with a time horizon from 00:00 to 0:00, 06:00 to 00:00 and 18:00 to 00:00, respectively.

To reflect the reserve market of Denmark, the Scheduling Model includes a demand for positive non-spinning reserves, referred to as replacement reserves, and a demand for positive and negative spinning reserves or ancillary services. Replacement reserves may represent tertiary reserve capacity in the Danish system whereas ancillary services correspond to primary reserves for Eastern Denmark and both primary and secondary reserves for Western Denmark. The modelling of reserves is investigated more thoroughly in the following sections.

1.2 The Danish case

The case study of WP7 is based on the data set of [EWIS]. Considering the year of 2006, data from this year has been used when available. When not, data from 2002 was found to provide good estimates. Denmark, being the country of main interest, is represented by two regions, whereas the surrounding countries considered, Norway, Sweden, Finland and Germany, each have one region. Special efforts have been made to update data for the regions of Denmark such that the modelling tools can be run with data that represented the latest information while actually operating. This serves to illustrate the situation where the modelling tools were run with *online* data by the TSO, which in real time would require an automatic update of data in the modelling tools. Historical time series of realised and forecasted load and wind power have been updated with data validated recently by the Danish TSO, Energinet.dk [Energinet]. Forecasts are made at the Danish weather service, once a day at 7:00 and wind power forecasts four times a day at 01:00, 07:00, 13:00 and 19:00. Wind power forecasts are made two days ahead whereas load forecast are made only for the following operation day. The time series of realised values are given by hourly measurements whereas forecasted values consists of hourly averages of values at :15, :30, :45 and :60. When single forecasted values were missing, these were derived from realised values and sample forecast errors, assuming independent normally distributed forecast errors to complete the data set. It should be remarked that the wind power forecasts are biased, especially for Western Denmark, cf. the systematic underestimation of realised wind power production in Figure 1 and *Figure 2*. This may be explained by problems in the power curve transformation between wind speeds and wind power. To obtain unbiased wind power forecasts, the forecasts have been transformed such as the forecast errors have a mean value of zero. Likewise, historical data have replaced the estimates of [EWIS] for maintenance and failure, referred to as scheduled and forced outage, of those units that report to the Nordic market, Nord Pool.

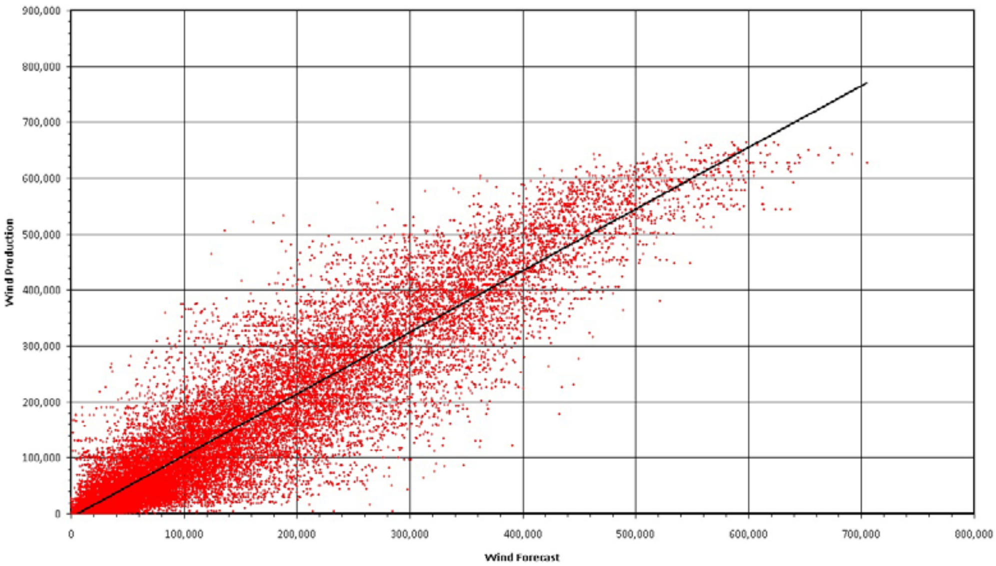


Figure 1 Wind power forecasts and production for Eastern Denmark, 2006.

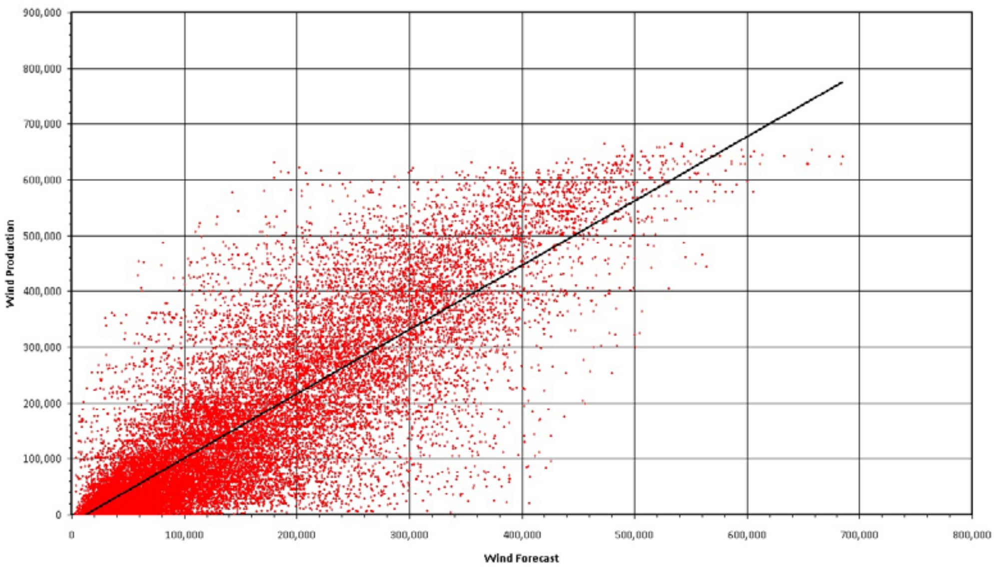


Figure 2 Wind power forecasts and production for Western Denmark, 2006.

1.3 Preliminary model results

To illustrate the use of the modelling tools for day-to-day operation and planning, the modelling tools have been run for the Danish case study, considering January and July 2006. The following presents results for January. The same conclusions can be made on the basis of results for July.

Expected load and wind power

A day ahead of operation the Danish TSO plans according to expected net load given by the difference between forecasted electricity demand and forecasted wind power. Expected net load is displayed in Figure 3. The mostly positive net load induces day-ahead scheduling of conventional production and import whereas the infrequent negative net load is handled by scheduling export a day ahead. When electricity demand dominates wind power, net load inherits its daily and weekly variations which reduces the difficulty of day-ahead prediction and thereby day-ahead scheduling.

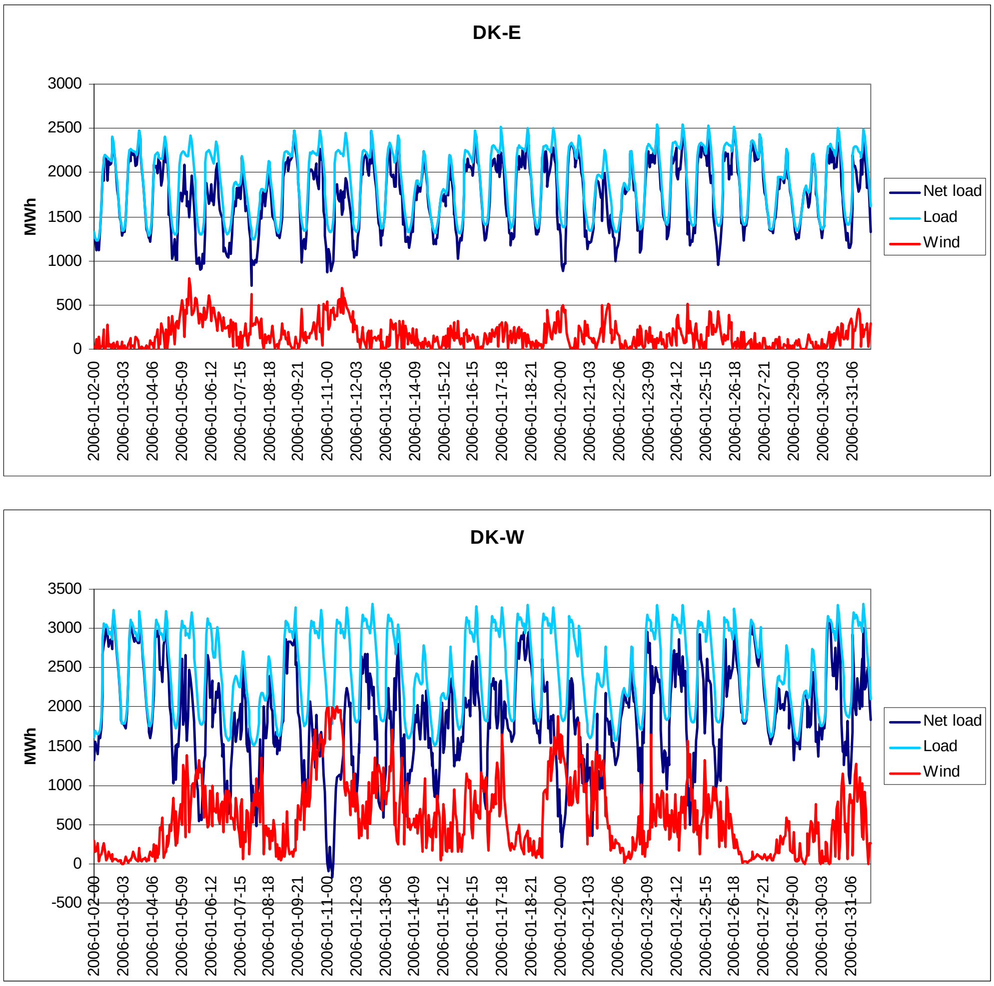
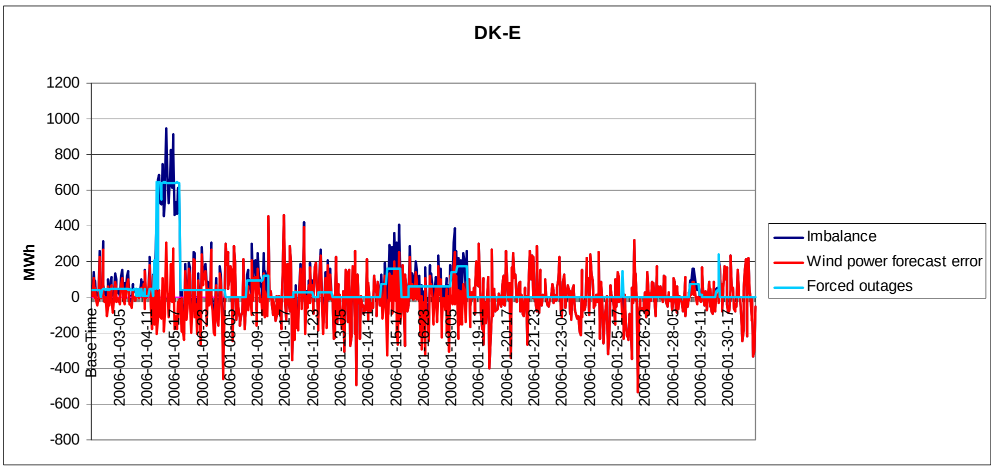


Figure 3 Net load forecast for Denmark, January 2006.

Imbalances

Due to imbalances caused by wind power forecast errors and forced outages of the generating units the day-ahead schedule may not exactly meet expected net load and rescheduling is necessary during operation. A forecast of the system imbalances faced by the TSO is shown in Figure 4. Positive imbalances occur more frequently than negative imbalances due to forced outages. A positive imbalance is offset by up-regulation of conventional production and by import and a negative imbalance by down-regulation and export. By means of stochastic programming, the Scheduling Model aims to assist the TSO in determining a day-ahead schedule that hedges against the uncertainty of system imbalances during the operation day.



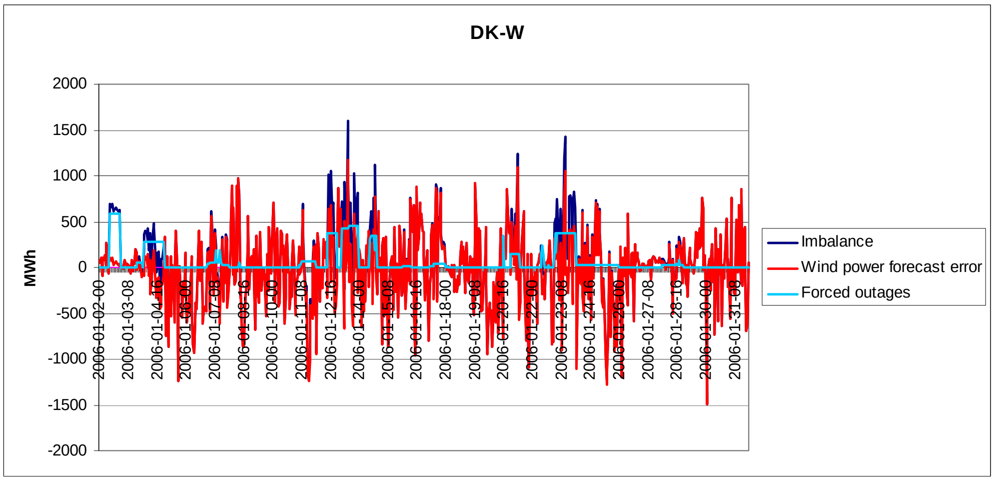


Figure 4 System imbalance (forecast) for Denmark, January 2006.

Renewable power production

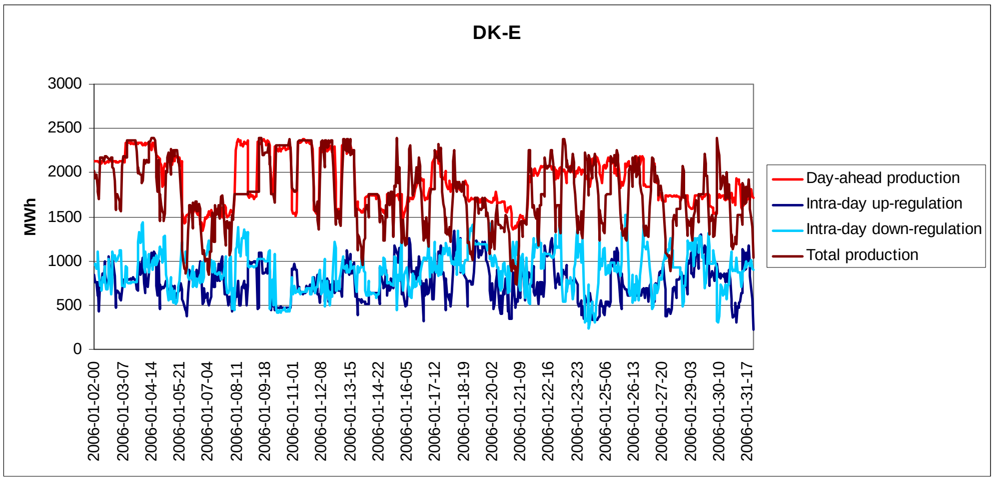
Since renewable power in Denmark notably includes wind power, this is displayed in Table 1. Installed capacity and total power production is higher in Western than in Eastern Denmark as already indicated above. Still, the capacity factors of wind are nearly the same for Eastern and Western Denmark, i.e. 22.38% and 25.87% in January. The shares of wind power production of total electricity demand are 8.73% and 25.28% in January for Eastern and Western Denmark, respectively, which suggests that net load is less predictable for Western than for Eastern Denmark.

Table 1 Average wind power capacity and total wind power production for Denmark, January 2006.

	Capacity	Day-ahead production	Intra-day production
	MW	MWh	MWh
DK-E	739.42	119121.28	113804.92
DK-W	2391.14	445325.11	422916.07

Dispatch of conventional power production

As concerns the dispatch of conventional power production, coal and natural gas constitute the main fuels. Natural gas and coal are both used for production scheduled day-ahead. Intra-day up-regulation is dominated by coal, its part-load efficiency being high, whereas both fuels serve as down-regulation. According to Figure 5, the day-ahead dispatch generally follows the trend of the net load but is rather stable, leaving a large part of the variations in net load to be handled by import and export. This does not apply within the operation day. The stability of the day-ahead dispatch may be explained by the hedging against uncertainty of intra-day imbalances and the possibility to defer start-ups and shut-downs. Occasionally, the day-ahead and intra-day dispatches do not follow the trend of the net load since import and export is profitable. The average utilization factors for conventional production are 76.40 % and 76.03 % for Eastern and Western Denmark, respectively. Online capacity may exceed production either to avoid the costs of alternating between shut-downs and start-ups or to start-up sufficient capacity ahead of operation when start-up times apply.



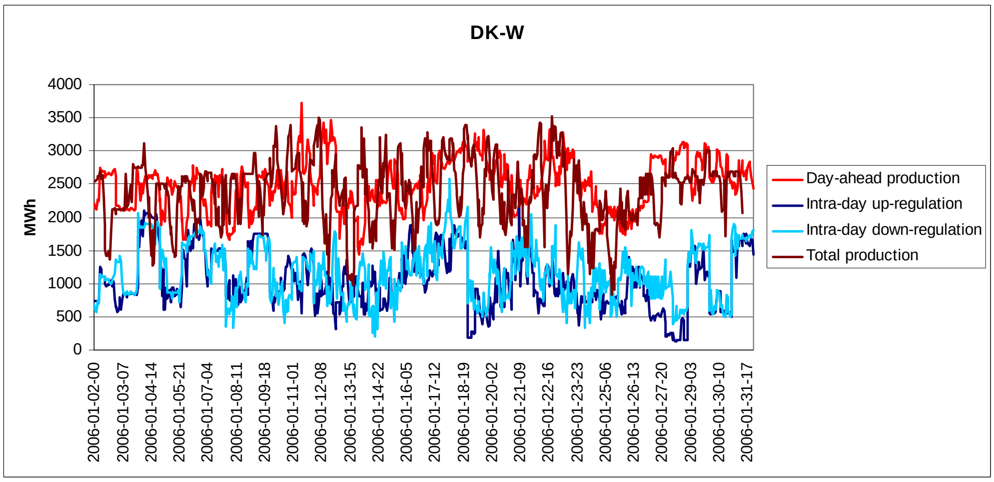
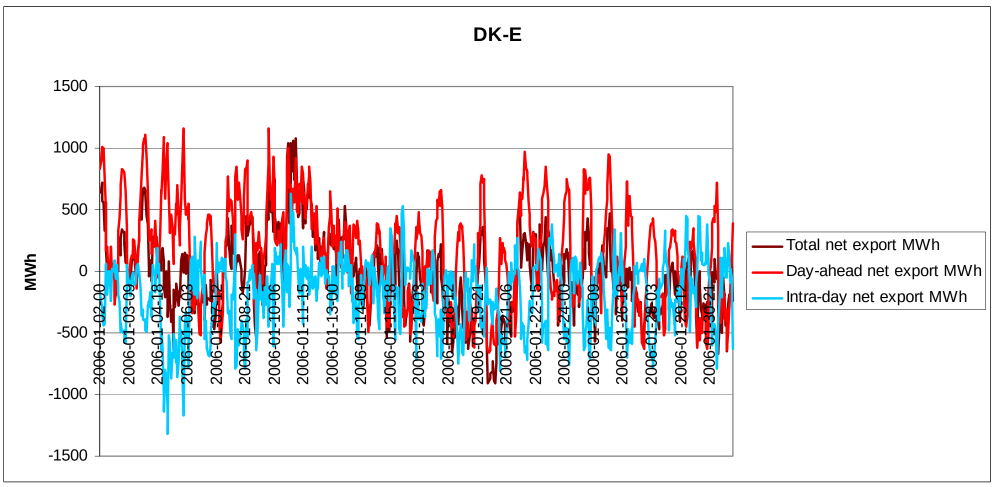


Figure 5 Dispatch of conventional production for Denmark, January 2006.

Power exchange

Denmark is divided into two regions, i.e. Eastern and Western Denmark, Eastern Denmark being connected to Sweden and Germany and Western Denmark to Norway, Sweden and Germany. Net export between the Danish regions and the surrounding countries is shown in Figure 6. As already mentioned, a large part of the variations in net load is handled by import and export day-ahead, inducing the reverse within the operation day. Additional power exchange may be profitable, the production costs of Denmark being different from those of the surrounding countries. This will be analysed more thoroughly in the following sections.



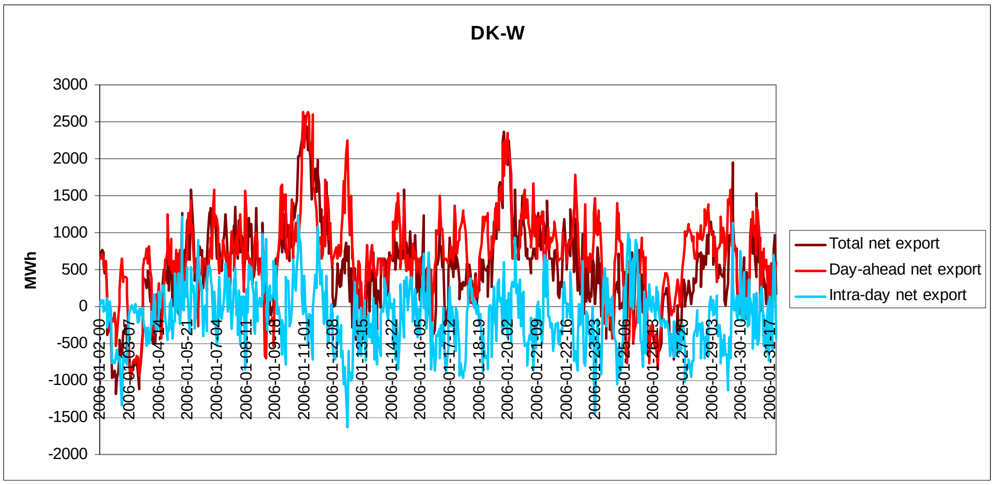


Figure 6 Net export for Denmark, January 2006.

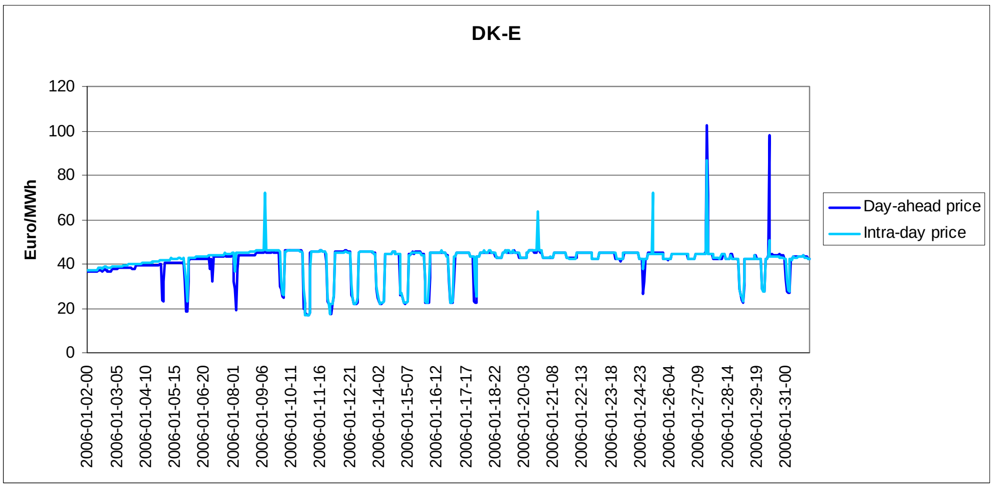
Operation costs consist of fixed start-up costs and variable operation costs, including operation and maintenance costs, fuel costs and emission costs. Total costs for 2006 are shown in Table 2. The allocation of operation costs between variable operation costs and fixed start-up costs depends on the production mix, e.g. OCGT's show small start-up costs but high operating costs whereas CCGT's show small operation costs but high start-up costs.

Table 2 Total operation costs for Denmark, including total fixed start-up costs, variable operation costs and emission (CO_2) cost. January 2006.

	Start-up costs	Fuel costs	O&M costs	Emission costs
	mill. Euro	mill. Euro	mill. Euro	mill. Euro
DK-E	0.42	54.09	3.81	19.61
DK-W	0.36	75.01	7.42	31.55

Prices

Danish day-ahead and intra-day prices are displayed in Figure 7. For both Eastern Denmark and Western Denmark, prices follow the trend of the net load. Eastern prices are more stable than Western prices which reflects the larger variations of net load in Western than in Eastern Denmark. However, for none of the regions it is immediately possible to determine whether conventional production or import/export is price-setting.



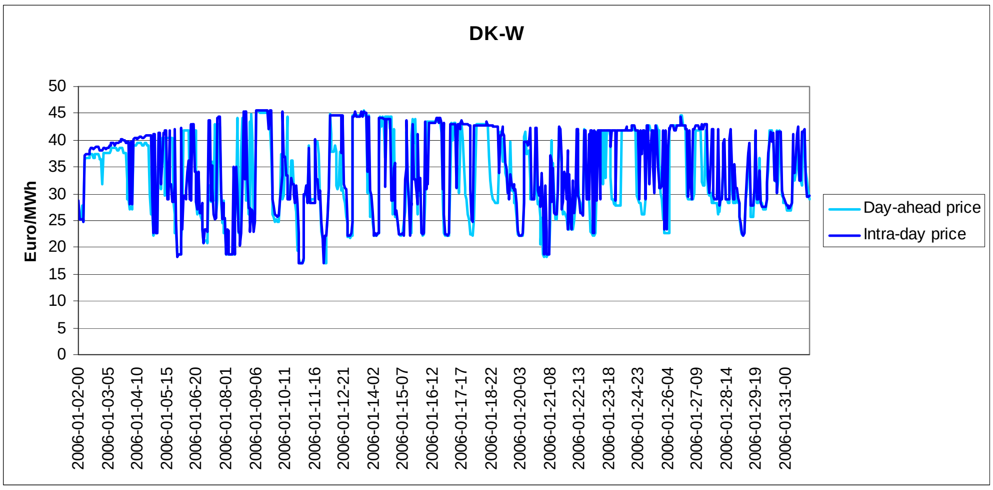


Figure 7 Day-ahead and intra-day prices in Denmark, January 2006.

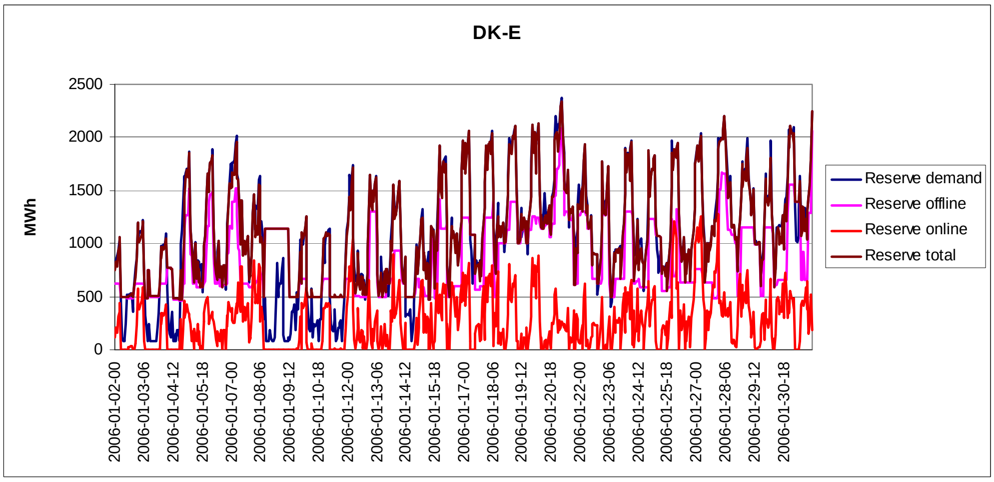
Reserves

For Denmark reserves are assumed to include positive and negative spinning reserves and positive non-spinning reserves. Spinning reserves should be sufficient to simultaneously cover an outage of the largest generating unit online and a fast decrease in the current wind power production. As these have to be immediately available, spinning reserves are activated a day ahead of operation and provided only by online units. The dispatch of spinning reserves is nearly constant over time. The average hourly dispatch of spinning reserves is shown in Table 3.

Table 3 Dispatch of spinning reserves for Denmark, January 2006.

	Positive reserves	Negative reserves
	MW	MW
DK-E	75.00	263.53
DK-W	110.00	35.00

Non-spinning reserves serves to cover extreme imbalances caused by wind power forecast errors and outages of the generating units. Hence, the more extreme the system imbalances, the larger the reserves. The demand for non-spinning reserves can be seen in Figure 8. Non-spinning reserves are activated during operation and may be provided by both off- and online units, reflecting that capacity has to be available but not necessarily online. As can be seen from the figure most of demand is covered by offline units.



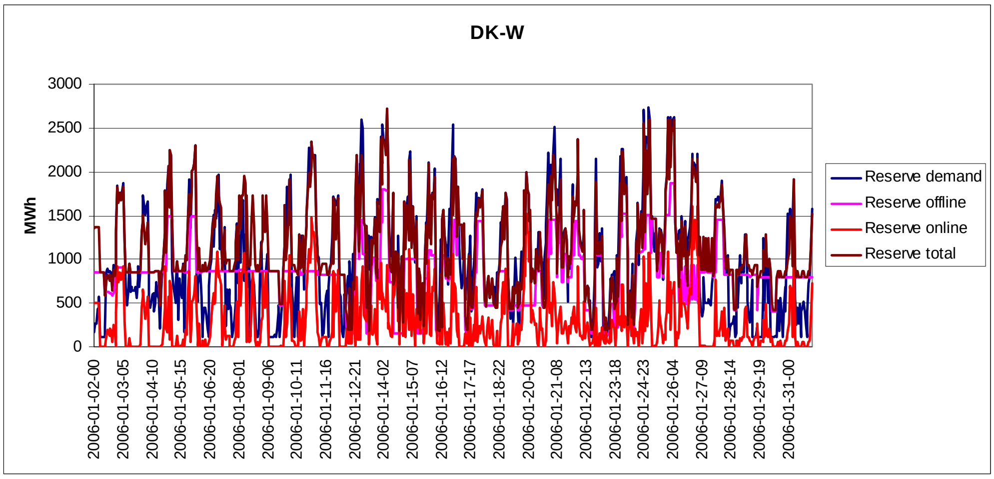


Figure 8 Demand and dispatch of non-spinning reserve for Denmark, January 2006.

1.4 Day-ahead planning: Historical evidence

In order to analyse the ability of the modelling tools to assist the TSO in operating the power system ahead of operation, this section compares the results of using the tools for day-ahead scheduling to historical data for the Danish case study, paying special attention to transmission flows. Obviously, the comparison can be made only when historical data is available. As previously, results are based on January and July 2006.

Day-ahead dispatch

Considering dispatch of conventional production, historical data only consists of observations within the operation day. For renewable power production, and specifically wind power dispatched a day ahead of operation, historical wind power forecasts are available. However, these have been transformed in order to remove bias and a direct comparison with the wind power forecast generated by the Scenario Tree Tool is infeasible.

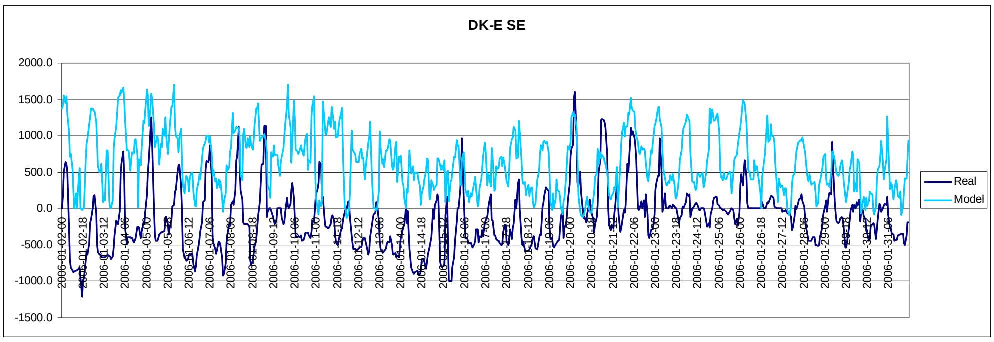
Day-ahead transmission

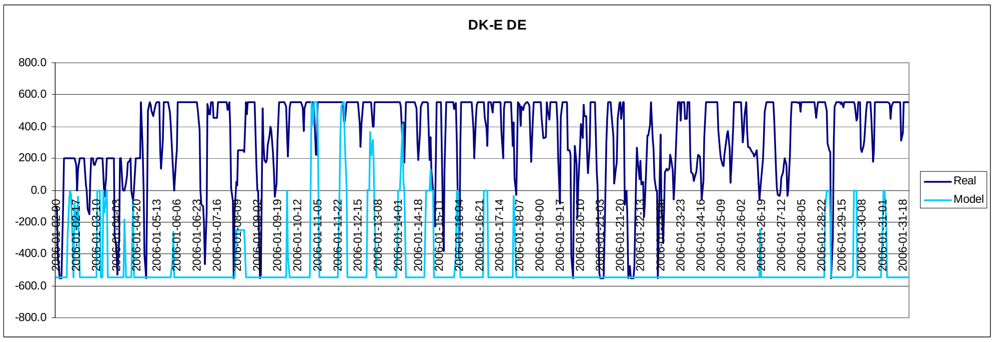
The results of running the Scheduling Model include the transmission flows scheduled a day ahead of operation. Figure 9 and Figure 10 compare these to historical transmission flows scheduled in the Nordic day-ahead market at Nord Pool. For both January and July, transmission flows display the same daily variations as historical flows. The general tendency is for Denmark to export (or decrease import) during the night and import (or decrease export) during the day in order to avoid excessive shut-downs and start-ups of the generating units.

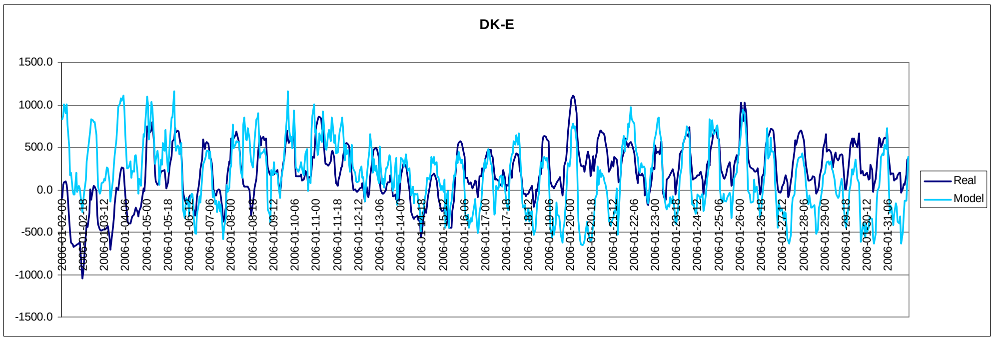
For January, total net exports of Eastern and Western Denmark can be verified by historical data. However, transmission flows in opposite directions. It may be argued that fuel prices for both Eastern and Western Denmark are too high compared to German fuel prices and too low compared to Norwegian and Swedish water values for January.

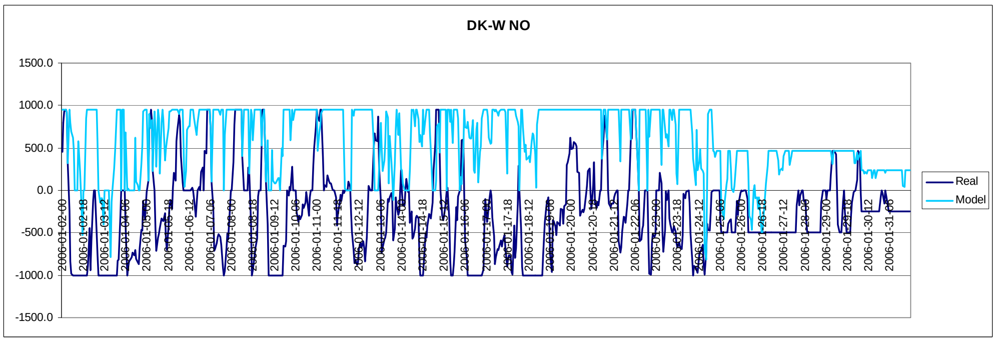
For July, transmission flows between Western Denmark and Norway closely follows the historical observations. Exchanges between Western Denmark and both Sweden and Germany are likewise backed up by historical data although net export is slightly less than observed in reality. The results indicate that fuel prices for Eastern Denmark are too high compared to German fuel prices and Swedish water values for July. Moreover, on one hand exchanges between Eastern Denmark and Germany follow the historical observations reasonably close. On the other, net export between Eastern Denmark and Sweden differs in such a way that net exports are higher than real in the beginning of the month and lower in the end. This suggests that Swedish water values vary more than was really the case during July.

The directions of transmission flows are induced by price differences between regions in the Scheduling Model and as a result the model-based flows are very sensitive to small differences in fuel prices and water values. The calibration of the model output against historical observations puts forward crucial requirements to the input data.









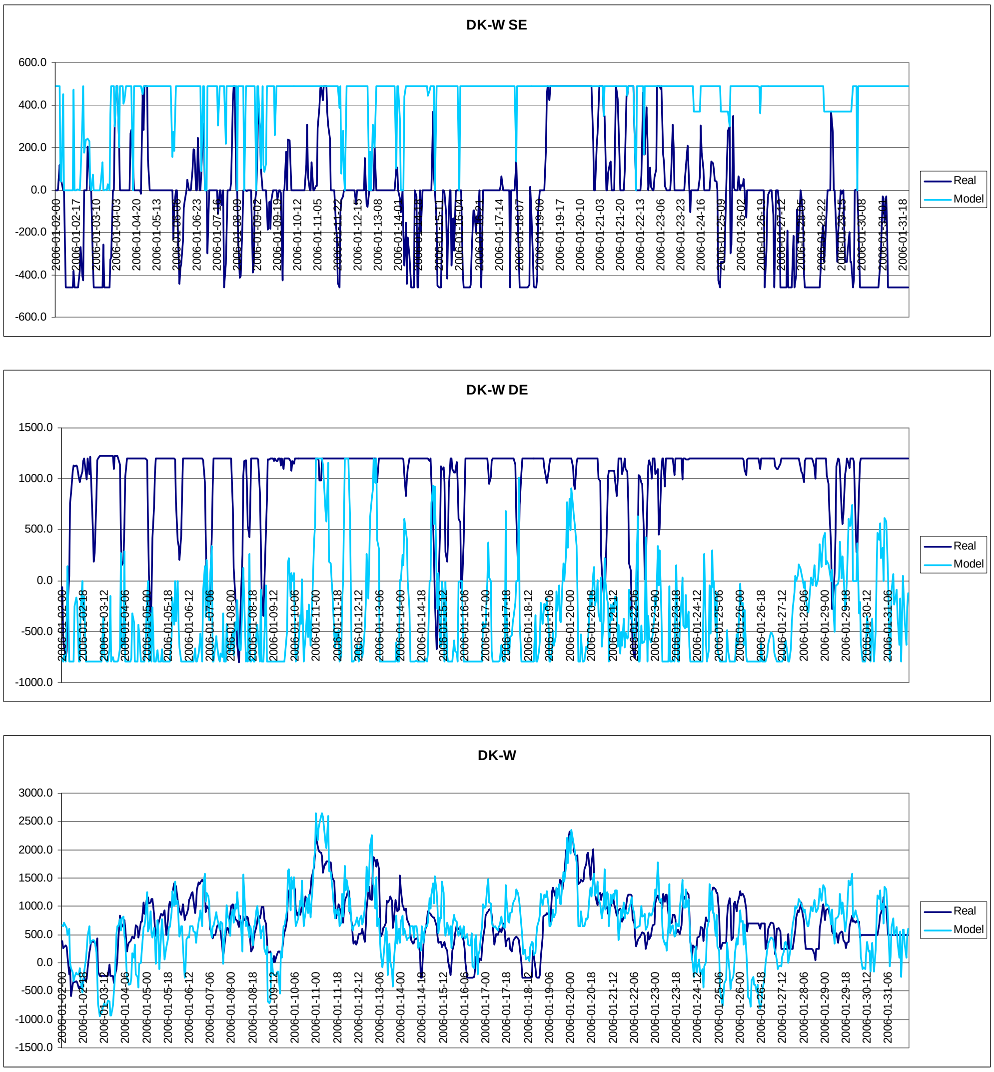
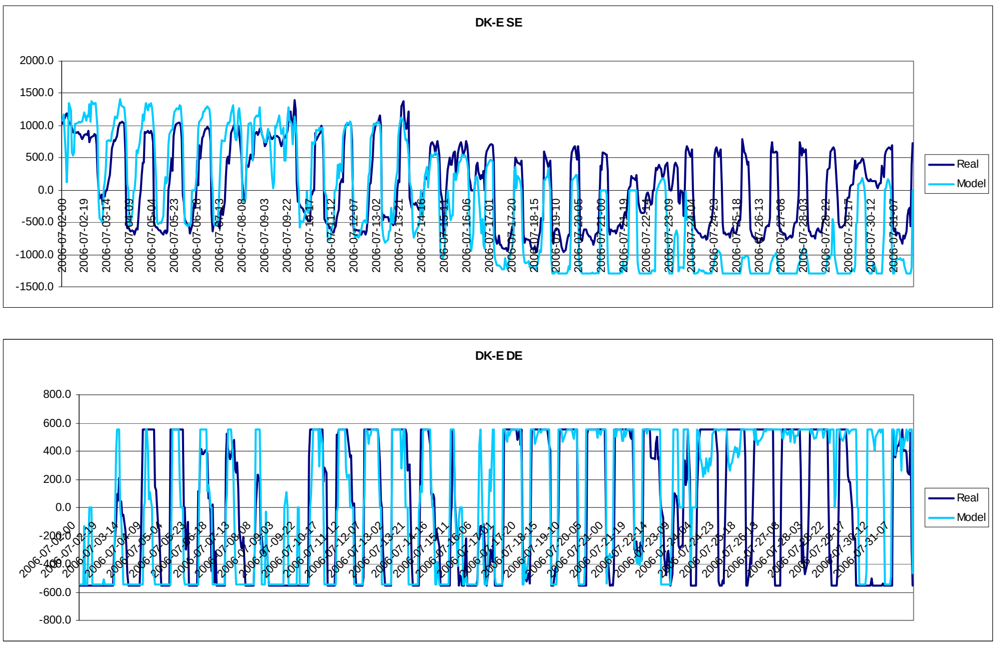


Figure 9 Historical and model-based day-ahead net export for Eastern and Western Denmark. The figures depict total net exports for Denmark and exchanges between Denmark and the surrounding countries. January 2006.



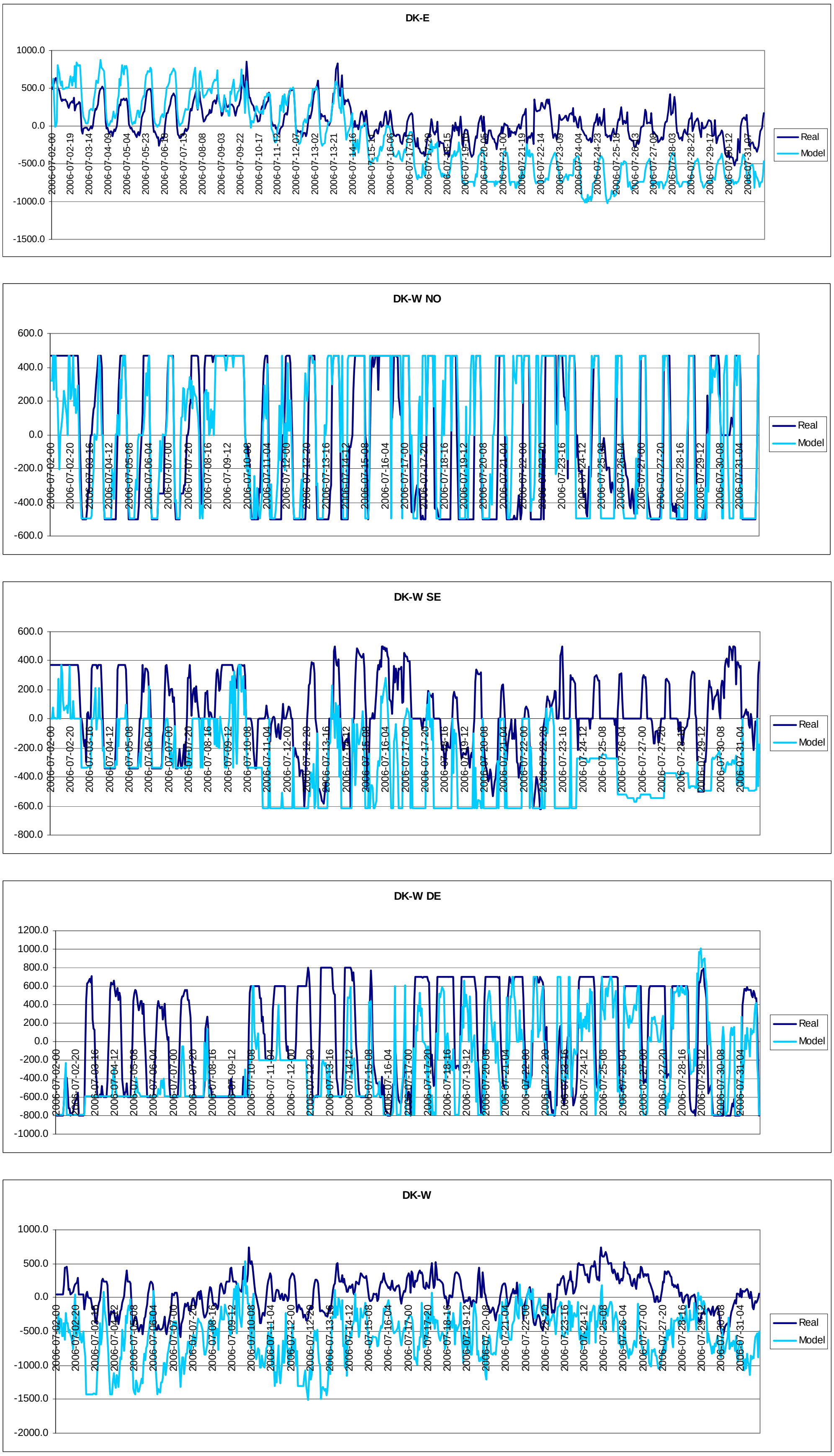
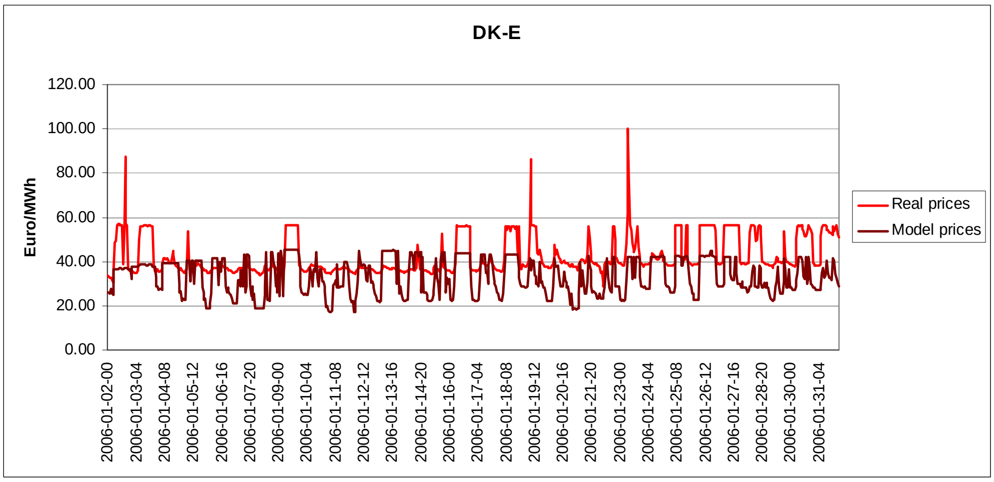


Figure 10 Historical and model-based day-ahead net export for Eastern and Western Denmark. The figures depict total net exports for Denmark and exchanges between Denmark and the surrounding countries. July 2006.

Day-ahead prices

Prices from the Nordic day-ahead market at Nord Pool facilitate a comparison between historical and model-based day-ahead prices. Model-based day-ahead prices are derived from the dual variables corresponding to the day-ahead equilibrium constraints in the linear program that arises from fixing the integer variables in the Scheduling Model. Due to the fixing of the integer variables, prices do not include start-up costs and may be lower than historically. Historical and model-based Danish day-ahead prices are shown in Figure 11 and Figure 12. For both January and July model-based prices are generally lower than historical prices. Apart from the price derivation, this may be explained by an underestimation of fuel prices in Denmark and Germany and water values in Norway and Sweden or by available capacity exceeding the real capacity of the power system.



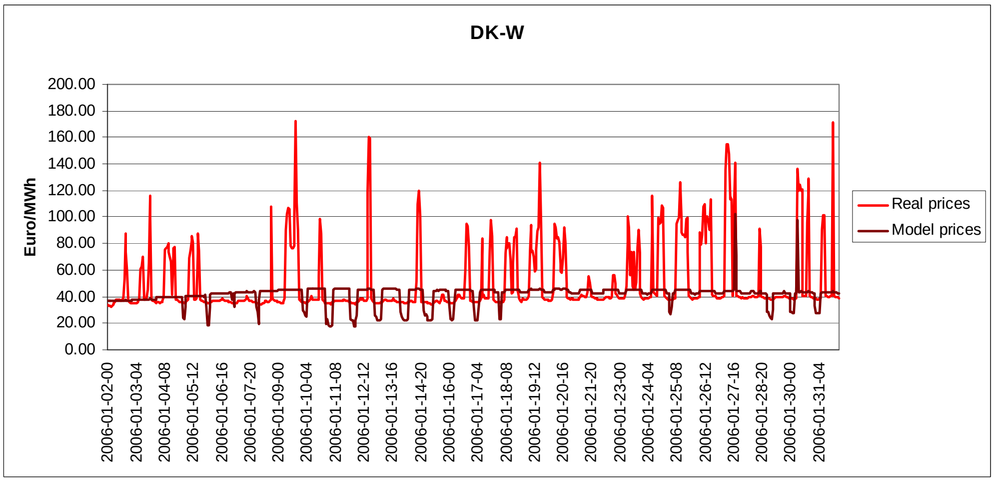


Figure 11 Historical and model-based day-ahead prices for Eastern and Western Denmark. January 2006.

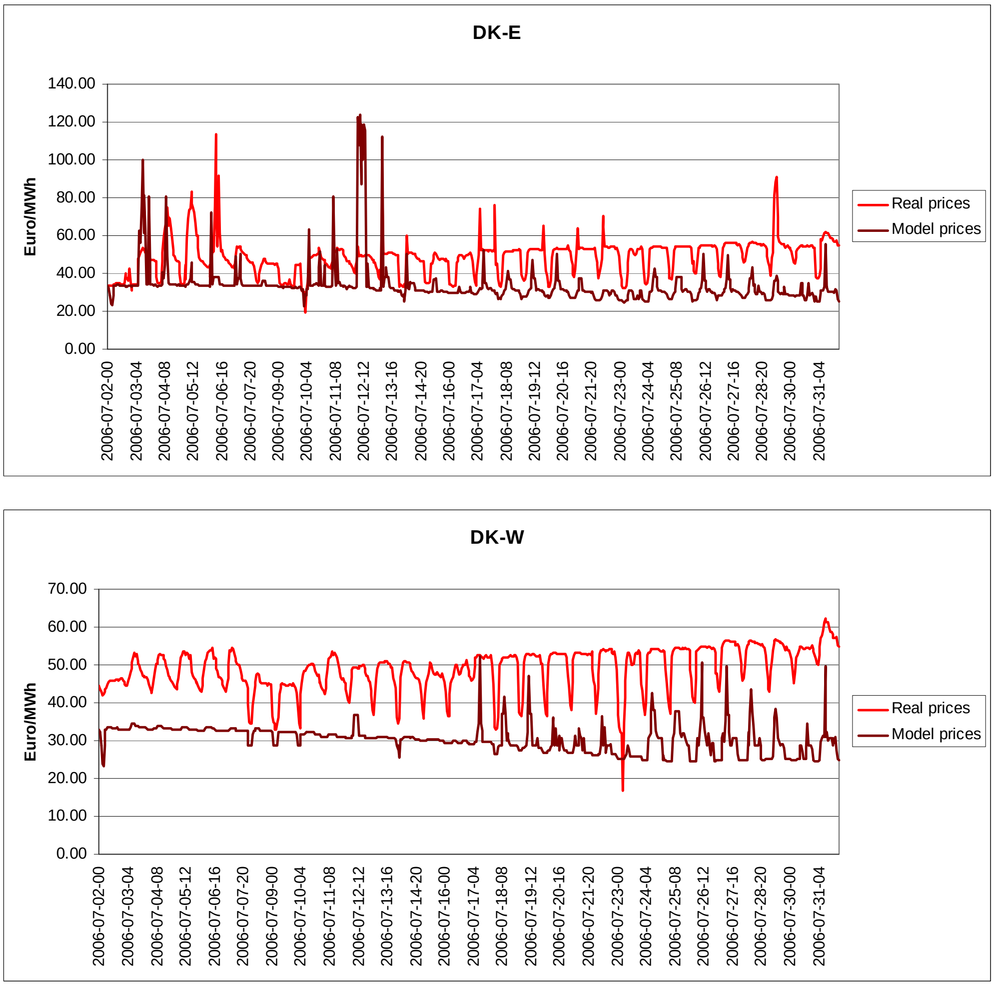


Figure 12 Historical and model-based day-ahead prices for Eastern and Western Denmark. July 2006.

Average historical and model-based day-ahead prices for the surrounding countries are shown in Table 4. Generally, the model-based price-level is lower than the historical. Still, the model-based prices may relate to each other in the same fashion as historically.

For January, model-based prices are lower in Denmark than in Norway and Sweden and higher than in Germany inducing export to the north and import from the south whereas the opposite applies historically.

For July, both model-based and historical price level are almost the same in Denmark and the surrounding countries, ignoring the occasional spikes that highly affect the German historical average. This is consistent with the model-based exchanges between Eastern Denmark and Germany and between Western Denmark and Norway closely following the historical. In contrast to the historical data, the model-based price in Eastern Denmark is slightly lower than the Swedish in the beginning of the month and slightly higher in the end of the month which complies with a higher export and import than historically. The same applies to Western Denmark for which the model-based price is slightly higher than the Swedish and German complying with a higher import than historically.

Table 4 Historical and model-based day-ahead prices for Eastern and Western Denmark, Norway, Sweden and Germany. Averages for January and July 2006.

		DK-E	DK-W	NO	SE	GE
		Euro/MWh	Euro/MWh	Euro/MWh	Euro/MWh	Euro/MWh
January	Model	41.34	32.97	40.51	41.54	29.82
	Hist.	50.05	42.32	39.15	40.32	66.93
July	Model	30.37	33.63	31.57	28.90	30.06
	Hist.	49.05	48.78	50.20	49.25	74.64

Further lines of research

The results and discussions of the previous sections indicate that the ability of the Scenario Tree Tool and the Scheduling Model to assist in day-to-day planning would be improved by further calibration. For the purpose of day-ahead scheduling, the modelling tools should be able to simulate the current state of the power system and calibration would consist in including updated information systematically and regularly. Suggestions for calibration are:

- Adjust water values in Norway and Sweden where hydro power accounts for large parts of total production. The results point in the direction of decreasing water values in January and increasing water values in July. Water values could be calibrated by using the average historical day-ahead price of the last week. Still, this would work only when fuel prices are accurate.
- Calibrate reservoir levels. Since model-based reservoir levels are already lower than historically for January and higher than historically for July, the data for initial reservoir levels may not be consistent with the remaining data.
- In the Scheduling Model water values are adjusted according to historical reservoir levels such that the values are increased in case model-based reservoir levels are lower than historical and decreased in case of the opposite. The results support a decrease of the speed of adjustment.
- Adjust the fuel prices of Germany. The results are in favour of higher fuel prices. As an attempt to calibrate model-based fuel prices to historical day-ahead prices, prices could be adjusted by the difference between the two.
- Identify marginal generating units for each region. This would provide further information on how to calibrate water values and fuel prices.

On one hand, the Scheduling Model suffers from the drawbacks of a fundamental model. Data requirements are immense and it is highly demanding to establish a consistent data set. Moreover, being a fundamental model the Scheduling Model relies on the assumption of complete markets which may not hold in practice. Calibration is a cumbersome task, in particular for day-to-day planning, and the modelling tools may be better suited for planning on longer time scales. On the other hand, the Scheduling Model easily allows for changes in the power system configuration such as outages of the generating units, introduction of new plants etc.

As illustrated, the Scheduling Model can be used for both day-ahead scheduling in an overall power system or to simulate specific parts of a system such as day-ahead transmission flows and prices. For simulation, econometric models may outperform fundamental models. Whereas the literature on forecasting transmission flows is sparse price forecasting is well known from the literature.

2 Simulation of day-ahead tertiary reserves.

Based on the Danish case study presented in Chapter 1 the idea is to analyse simulations made by the STT. This chapter will perform a comparison between STT results and operational data on which some conclusions are drawn.

2.1 Introduction

Tertiary reserves are the reserves with an activation time longer than 5 and less than 15 minutes. These are mostly non-spinning reserves and in general terms they are referred to as manual reserves or regulating power. They are purchased on the Nordic power exchange, Nordpool, in the regulating power market. It is very important for the TSO's that enough power is offered on the regulating power market otherwise they will have problems balancing the power in the hour of operation. Hence, the TSO's has a demand for regulating power. If the TSO's are afraid that there will be a lack of regulating power offered in the regulating power market they choose to reserve the capacity from being sold in the spot market. This means that the TSO will pay an option price to the operators in order to have the operators to save some capacity to the regulating power market. One can discuss if demand for replacement reserves should be compared with the options that are taken out before the spot market or if it should be compared with the amount of available capacity in the Regulating Power market.

2.2 Replacement Reserves

The tertiary reserves cover the bigger part of the error on the wind and the load forecast and the forced outages of units. The rest, the smaller part, of these errors are covered by primary and secondary reserves, these are also called spinning reserves. In the Scheduling Model one reserve category named replacement reserve is used to cope with these uncertainties in an activation time of 5 minutes or more, and three reserve categories are representing the demand for spinning reserves with activation times lower than 5 minutes. The demand for replacement reserves is determined by the Scenario Tree Tool corresponding to the total forecast error of the power system considered which is defined according to the hourly distribution of wind power and load forecast errors and the possibilities of forced outages. Since the forecast errors and the probability of outages vary during the time, the demand for replacement reserves varies as well. Furthermore, since the Joint Market Model considers individual scenarios of the forecast error within the scenario tree, the demand for replacement reserves varies within the scenario tree, too. Thereby it is assumed that a certain percentile of the total forecast error has to be covered by the replacement reserves. Before the methodology of the determination of the demand for replacement reserves is illustrated, considered indices and parameters are defined:

Indices:

r:	model region
g:	generating unit
g(r):	generating units in region r
n:	node in the scenario tree
t:	hour t
t_0:	the first hour of the scenario tree, i.e. the hour when the wind power forecasts are made
f:	the horizon for the wind power production forecasts, i.e. f = (1,2,3, …, 36)
i:	number of generated scenarios
s:	scenario
$s_F(n,f)$:	the part of unreduced scenarios that belong to node n, i.e. the unreduced scenarios s covering the hours f belonging to node n that are bundled into n by the scenario reduction algorithm

Parameters:

$W_E(r,t_0,f)$: expected wind power production in region r, in time t_0 at forecast horizon f considering the weighted average of the forecast scenarios

$W_F(r,t_0,f,s)$: forecasted wind power production in region r, in time t_0 at forecast horizon f in scenario s

$L_E(r,t_0,f)$: expected load in region r, time t_0 at forecast horizon f considering the weighted average of the forecast scenarios

$L_F(r,t_0,f,s)$: forecasted load in region r, time t_0 at forecast horizon f in scenario s

$C(r,g)$: installed capacity of generating unit g in region r

$Y(r,g,t)$: state (available or unavailable) of installed capacity of generating unit g in region r in time step t in scenario s

$P_{Ref}(r,t)$: reference of the power balance in region r in time t

$P(r,t_0,f,s)$: power balance in region r in time t_0 at forecast horizon f in scenario s

$\Delta P(r,t,n)$: total forecast error in region r at time t in node n

$\Delta P_{nth}(r,t,n)$: n^{th} percentile of the total forecast error in region r at time t in node n

The methodology proceeds as follows:

1. Generate i scenarios of wind power forecasts $W_E(r,t_0,f,s)$ in region r in time t0 at forecast horizon f based on Monte-Carlo-simulations, compare section **Error! Reference source not found.**.
2. Generate i scenarios of load forecasts $L_E(r,t_0,f,s)$ in region r in time t0 at forecast horizon f based on Monte-Carlo-simulations, compare section **Error! Reference source not found.**
3. Generate scenario of $Y(r,g,t)$ describing availability / unavailability capacity of each generating unit g at forecast horizon f in time step t based on Monte-Carlo-simulations of Semi-Markov processes, compare section **Error! Reference source not found.**
4. Determine the reference of the power balance P_{Ref} in model region r at time step t. Since perfect foresight cannot be assumed, the reference power balance P_{Ref} has to consider the expected wind power feed-in and load as well as the installed capacity minus scheduled outages but ignoring forced outages:

$$P_{\text{Ref}}(r,t_0) = \sum_{g \in G(r)} C(r,g) + W_E(r,t_0,f) - L_E(r,t_0,f) \tag{1}$$

5. Determine the power balance of scenario s. Thereby the hours of the forecast horizon f are allocated to the corresponding hours of the Markov chains describing the availability of the generating unit g. The individual scenarios of wind power forecasts, load forecasts and forced outages are randomly allocated to each other.

$$P(r,t_0,f,s) = \sum_{g \in G(r)} C(r,g)Y(r,g,t) + W_F(r,t_0,f,s) - L_F(r,t_0,f,s) \tag{2}$$

6. Determine the difference between the reference power balance and the power balance of scenario s. This is equal to scenarios of the total forecast error within the considered region r due to errors of wind power forecasts and of load forecasts as well as of forced outages (t is equal to t_0 + f):

$$\Delta P(r,t_0,f,s) = P_{\text{Ref}}(r,t) - P(r,t_0,f,s) \tag{3}$$

7. The number of scenarios s of wind power and load forecasts is reduced according to the applied scenario tree. Thereby it is recorded which scenarios are represented by a reduced scenario belonging to node n, i.e. which scenarios represent the set of scenarios $s_F(n,f)$ belonging to node n (see Figure 13) . Based on this allocation, the distribution of the total forecast error $\Delta P(r,t,n)$ in the considered region r of node n in time t is determined.

8. Determine the e.g. n^{th} percentile of $\Delta P(r,t,n)$, labelled $\Delta P_{nth}(r,t,n)$. This percentile of the total forecast error is considered to be the demand of replacement reserves. The direct dependency between the size of the percentile and the size of the demand for replacement reserves is clear from Figure 14. Smaller percentiles give smaller demand for replacement reserves. For more information see the Supwind report [WP3].

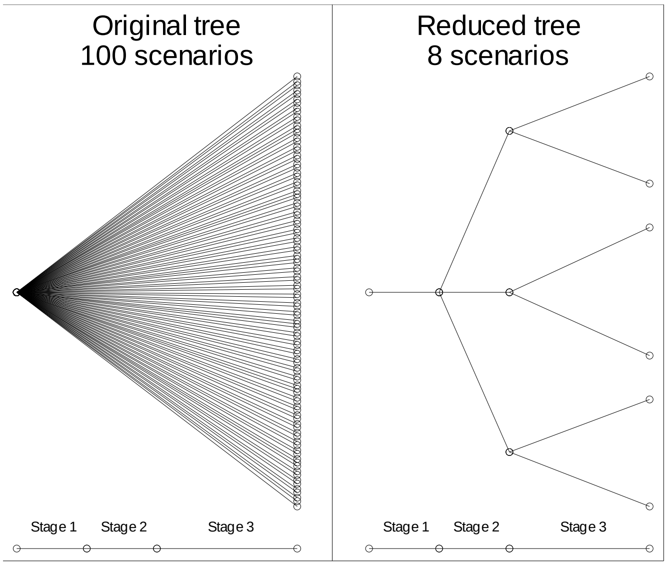


Figure 13 Illustration of tree reduction with 100 scenarios being reduced to a tree with the specification, 1 node in the first stage, 3 nodes in the second stage and 6 nodes in the third stage. Each of the nodes in the Reduced tree represents on average 100, 33 and 12.5 of the original scenarios in each node in stage 1, 2 and 3 respectively.

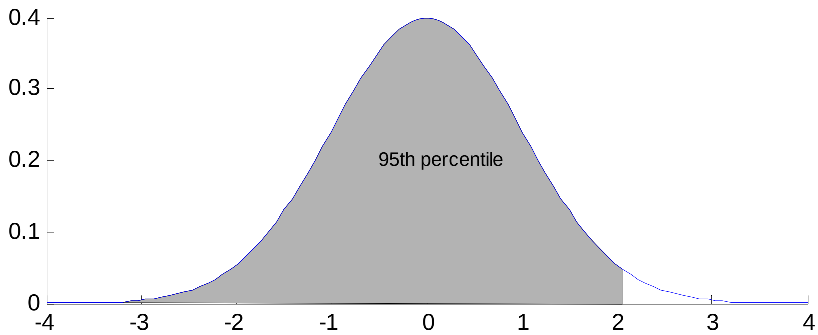


Figure 14 Illustration of distribution with 95th percentile

The largest effect on the demand for replacement reserves is the wind power forecast. The two regions, Denmark West and Denmark East, have different installed wind power capacity.

Region	Installed Capacity
Denmark West	2391
Denmark East	739

2.3 Results - Preliminary - Percentiles

In this section we would like to investigate if the preliminary results of the STT behave as expected. Regions with a large installed wind power capacity gives rise for large wind power forecasts error. The error on load forecast and the error on forced outages of units are expected to be more or less equal in all regions as these are not depending on any features in the region. The unbalance is, as mention in earlier section, derived from these errors. This is a direct influence on the demand for replacement. Based on this the region with the largest installed wind power capacity is expected to have the highest demand for replacement reserves. This is investigated in the following figure where P is the percentile.

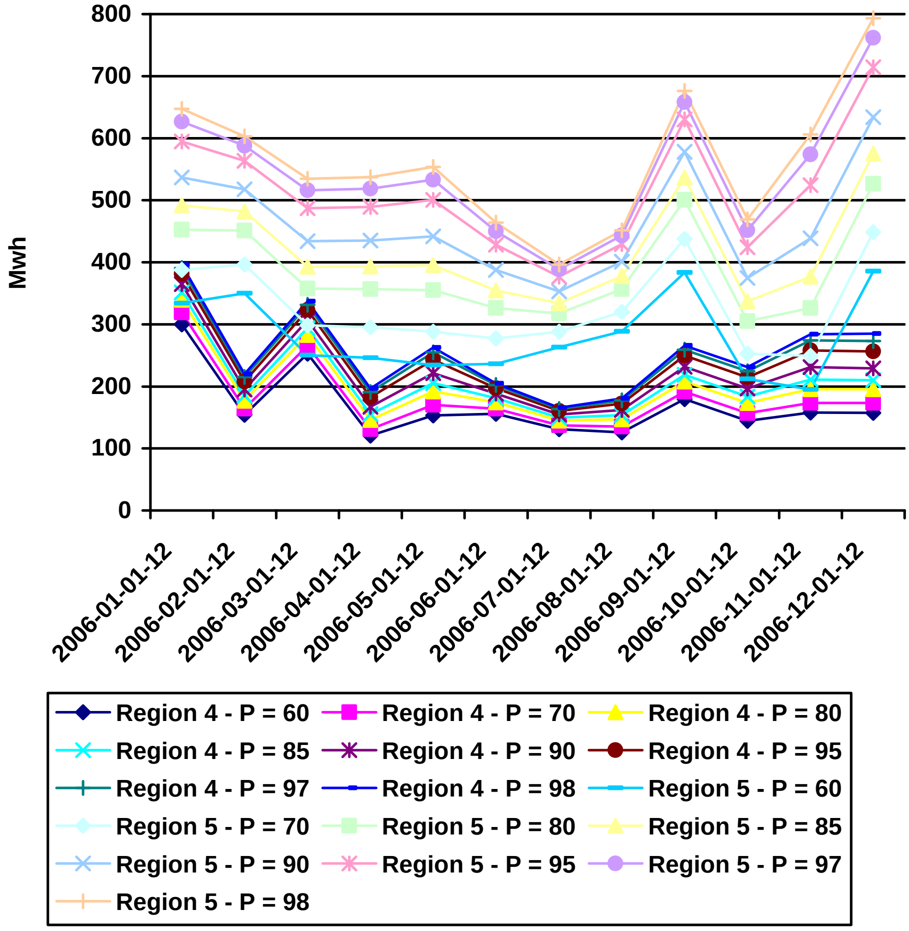


Figure 15 Monthly average demand for replacement reserves

The plot in Figure15 is clearly divided in two groups. Denmark West is the highest group because it has the largest installed wind power as expected.

The demand for replacement reserves is expected to decrease for decreasing percentiles. This is further investigated in the figures below.

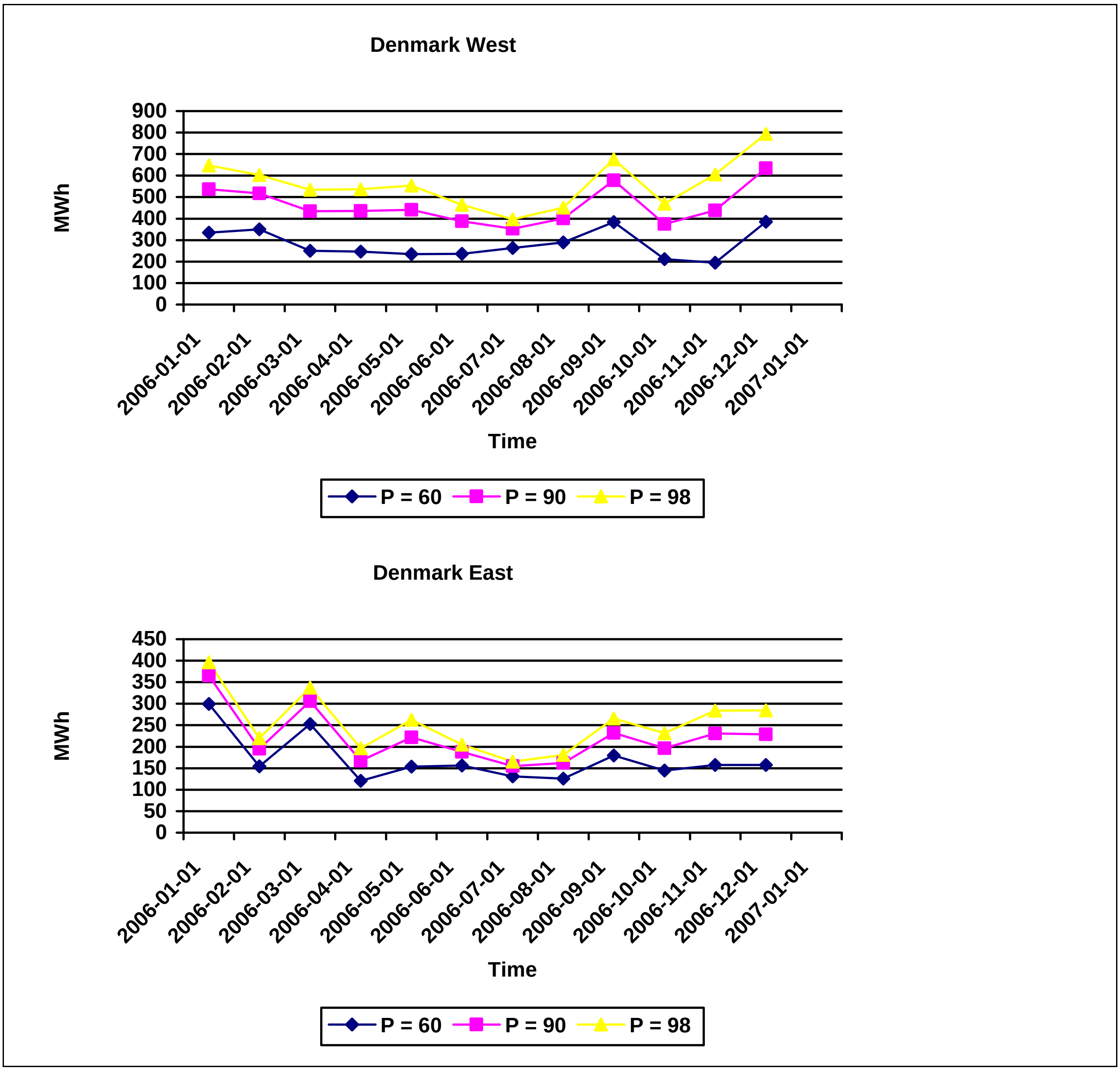


Figure 16 The demand for replacement reserves for increasing percentiles

In both regions the replacement reserves decrease with decreasing percentiles. The 98th percentile gives the highest demand for replacement reserves and the 60th percentile gives the lowest demand for replacement reserves. This corresponds perfect with the theory explained together with Figure 14.

2.4 Results - Forecast horizon

The wind power forecast will in this section be investigated with respect to the wind tree and the demand for replacement reserves dependent on forecast horizons in both regions. The four wind power forecasts each day cover different time spans of the day. The time spans in Figure 17 are aligned so it covers the right periods.

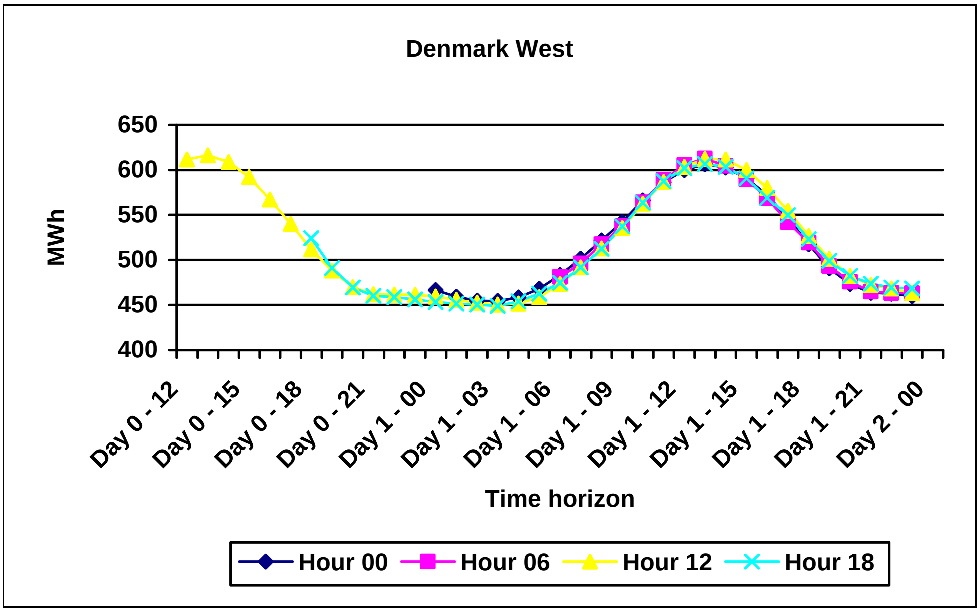


Figure 17 Yearly average of historical wind power forecast dependant on the time horizon

From Figure 17 we see that the wind power forecasts generated at four different times during the day, with different forecast horizons, do not change from one forecast time to another. The average of wind power forecasts do not depend on the forecast horizon but on the time of day which was expected.

The wind power forecast errors are expected to increase with increasing horizon. The errors are the difference between the forecasts of expected wind power, see Figure 17, and the generated wind power trees containing possible future wind power realisations, see Figure 13. The real wind powers are not known at this point in time hence the errors are calculated in this way. In Figure 18 the errors are plotted dependant on time horizon.

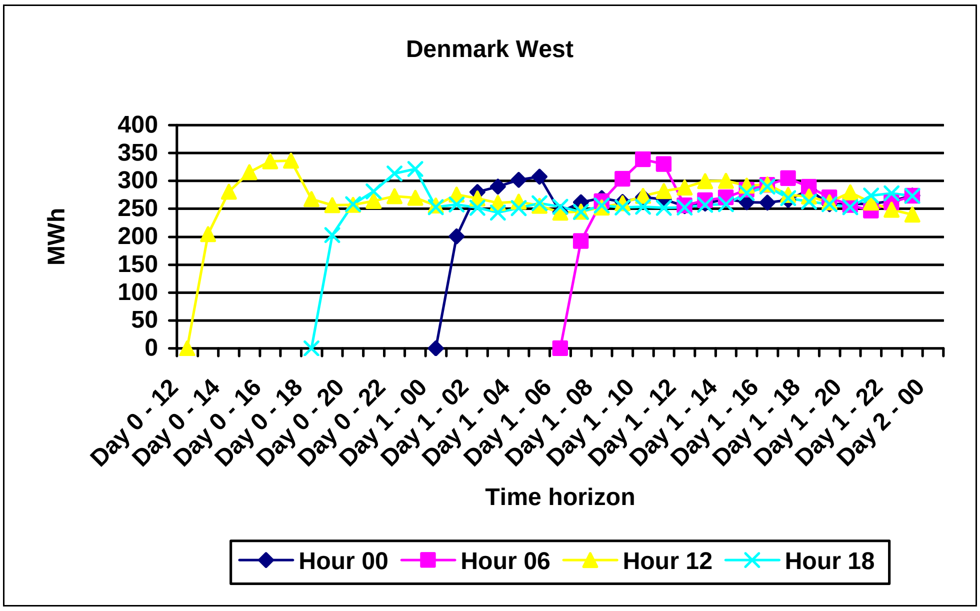


Figure 18 Yearly average of wind power forecast error dependant on the time horizon. P = 90.

In Figure 18 the four wind power forecast errors having different horizons are shown. In the first stage of the forecast horizon from one to six hours, the wind power forecast errors increase as expected. In the second stage the forecast errors decrease relatively to the last 3 hours in the first stage. Real world wind power forecast tools show increasing or stable wind power forecast errors as a function of forecast horizon. Further work is needed to investigate what causes the decrease in second stage wind power forecast errors compared to the forecast errors in the last hours of the first state.

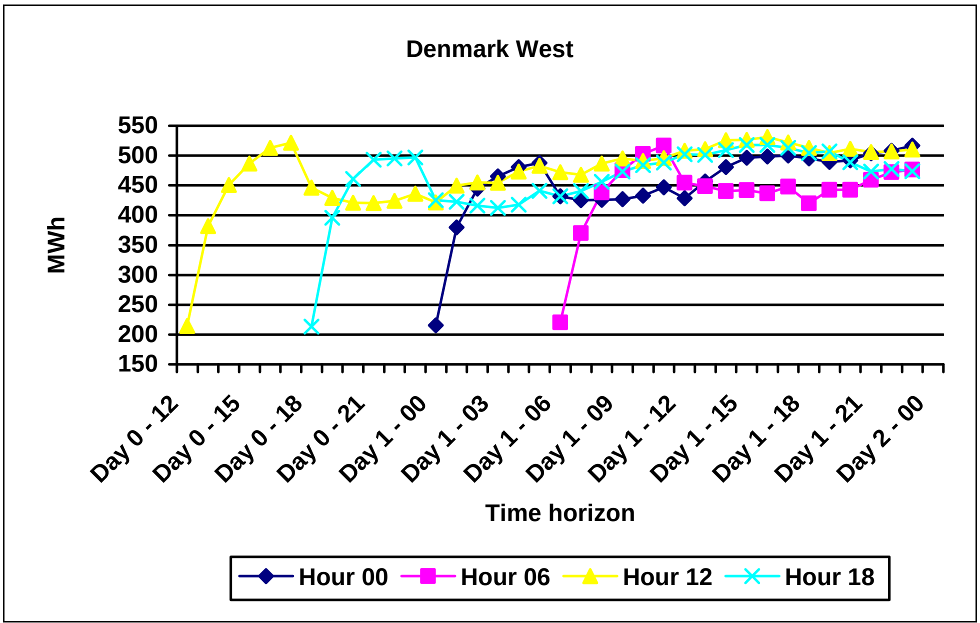


Figure 19 Yearly average of demand for replacement reserves dependant on the time horizon - P = 90.

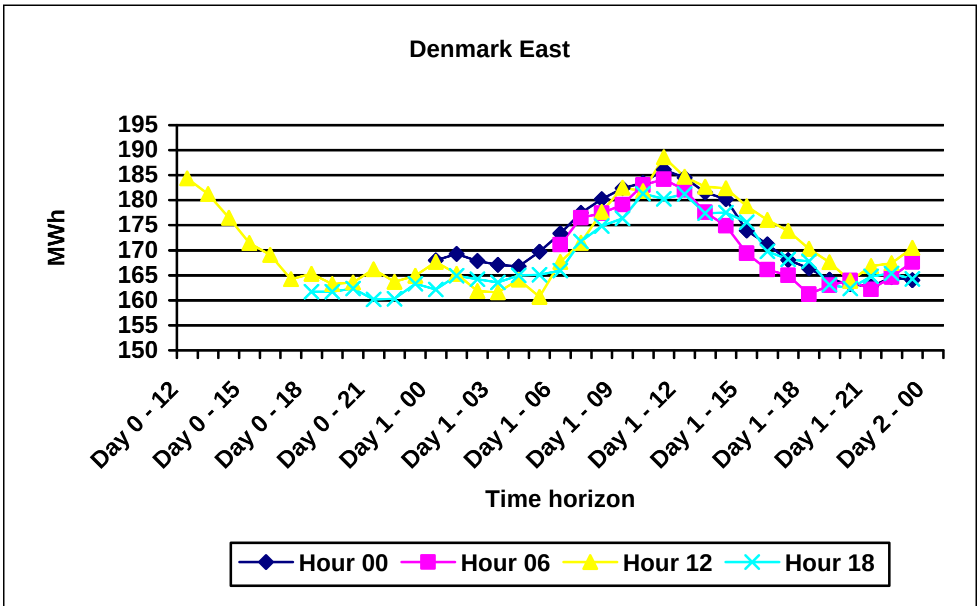


Figure 20 Yearly average of Wind forecast dependant on the time horizon

The result derived in the western part of Denmark is expected to be confirmed in eastern part of Denmark. The wind power forecasts for Denmark East are plotted dependant on time horizon.

In Figure 19 the demand for replacement reserves for the four different wind power forecasts having different horizons are shown. Like in Figure 18 the demand for replacement reserves increase with increasing horizon and as the errors on the wind power forecast increase. The change from stage one to stage two affect the demand for replacement reserves as it did the wind power forecast errors.

In Figure 20 we see that the wind power forecast has the same dependency on the time horizon as was expected and as the wind power forecasts in the western part of Denmark, Figure 17. There is a larger difference between forecasts with different forecast horizons. This means that new forecasts give more new information than it was the case in Denmark West. It is again expected that the wind power forecast errors increase with increasing horizon. This is investigated in Figure 21 where the wind power forecast error is plotted.

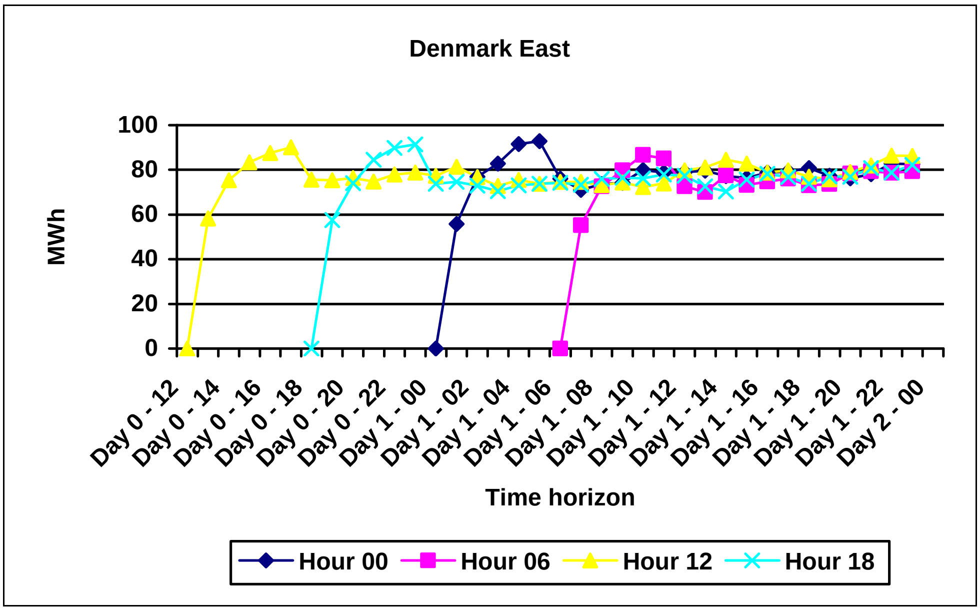


Figure 21 Yearly average of Wind power forecast error dependant on the time horizon   P = 90

The wind power forecast errors behaves as those for Denmark West and the demand for replacement reserves are expected to show some similar behaviour in Figure 22.

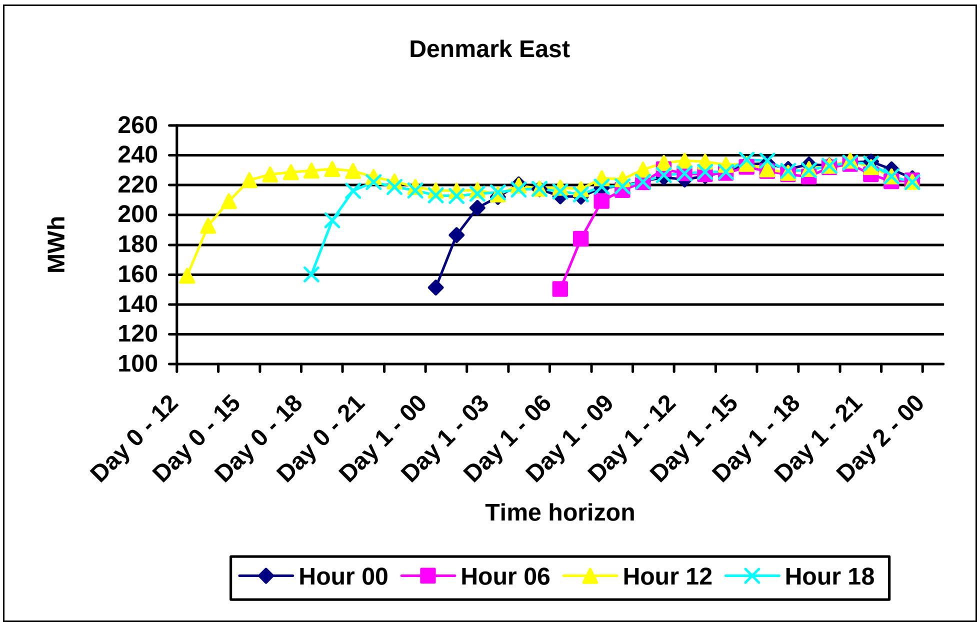


Figure 22 Yearly average of demand for replacement reserves dependant on the time horizon - P = 90

In Figure 22 we see the same effect in stage 1 on the demand for replacement reserves as it was case in the western part of Denmark, Figure 19. The effect seems smaller and can be explained by the smaller influence of wind power forecast errors on demand for replacement reserves due to less installed wind power capacity in Denmark East compared to Denmark West.

The postulation, given last in section 2.2, that the wind power forecast has the largest effect on the demand for replacement reserves has been confirm for both regions. The demand for replacement reserves increase as the wind power forecast errors increase and the demand for replacement reserves decreases as the wind power forecast errors decreases after the six hours.

2.5 Results - Day ahead vs. Six hours ahead

In this section we will look at the effect of horizon on the demand for replacement reserves. It is expected that the uncertainty will decrease the closer to the hour of operation it is calculated. It is therefore also expected that the demand for replacement reserves will decrease as the hour of operation is approached. Hence, the demand for replacement reserves calculated at 12 a.m. prior to the day of operation are expected to be larger than the demand for replacement reserves calculated with the latest wind forecast before the hour of operation.

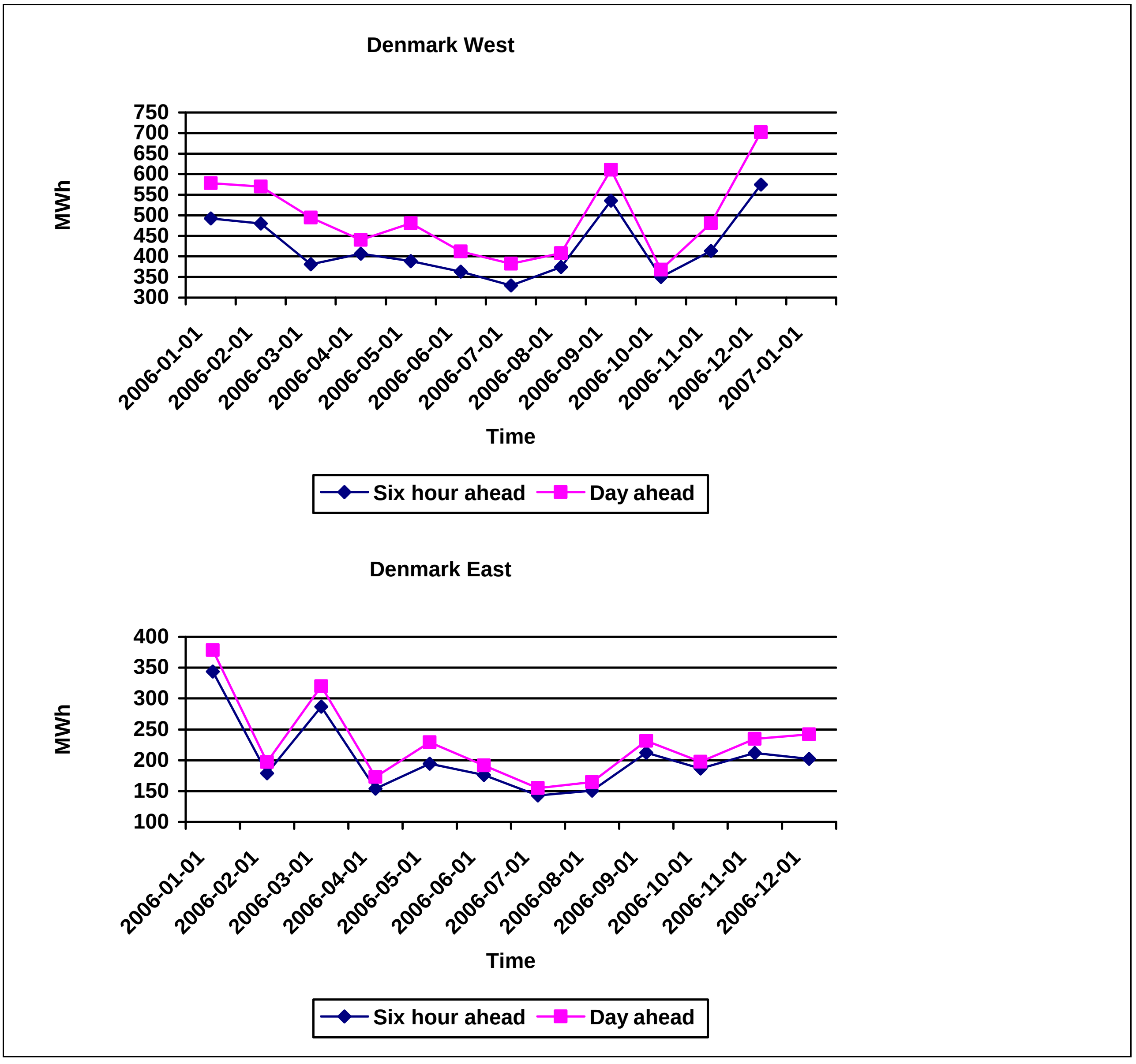


Figure 23 Monthly average of demand for replacement reserves with different forecast horizon - P = 90

The Six hour ahead demand for replacement reserves from Figure 23 is in general smaller than the Day ahead demand for replacement reserves, as expected. It can also be seen that this conclusion applies to both regions.

The STT assures that the demand for replacement reserves always have values above demand for spinning reserves. For the demand for replacement reserves with very low percentiles this constraint is removed. They would else be equal to the demand for spinning reserves.

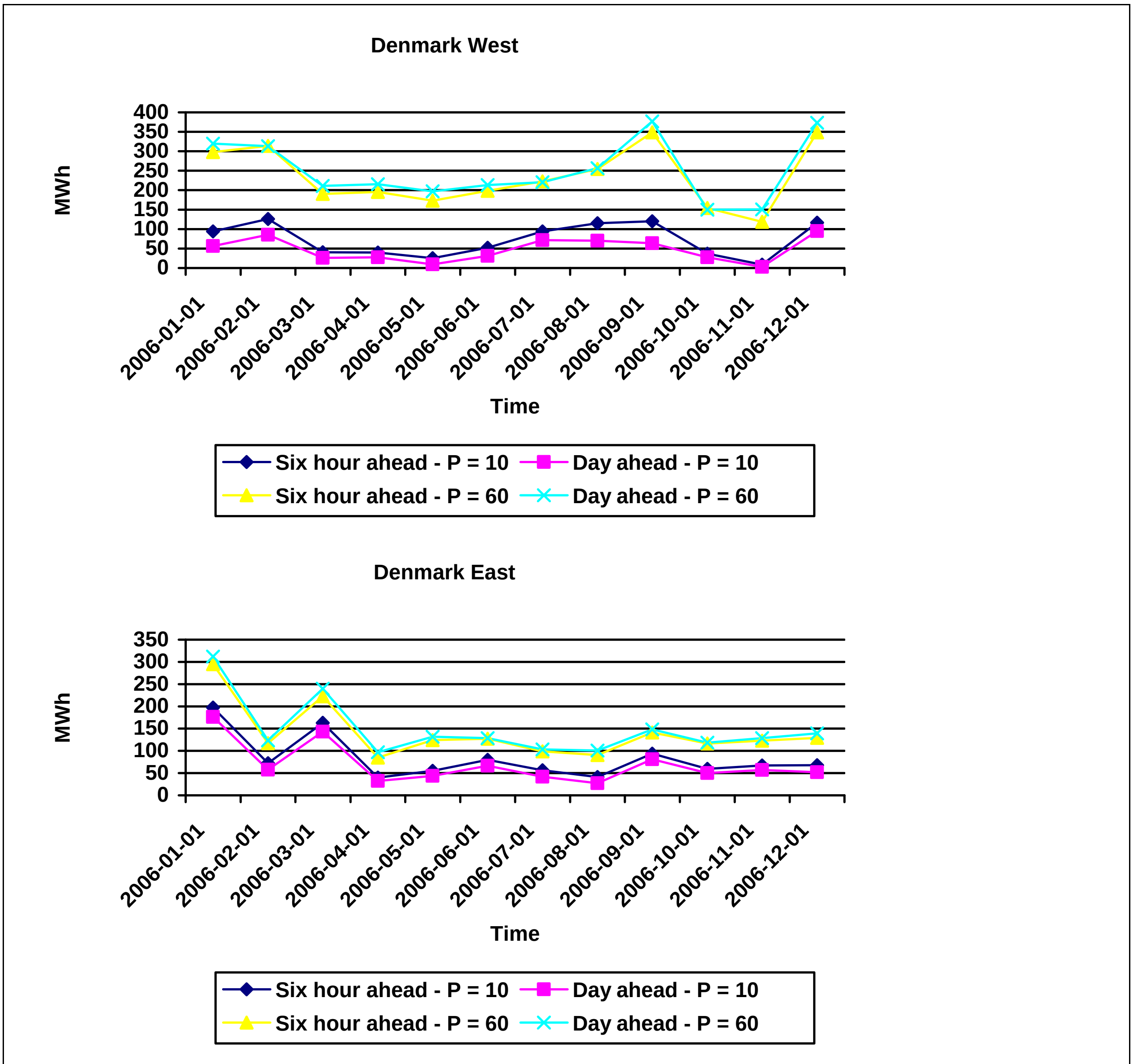


Figure 24 Monthly average of demand for replacement reserves with different forecast horizon

In the above figure the Six hour ahead demand for replacement are slightly higher than day ahead demand for replacement reserves when the percentile get low enough, e.g. P = 10. This does not cohere with the methodology for determining replacement reserves. It is more likely that the demand for replacement reserves with different forecast horizon are equal and that the difference is happenstances. This conclusion accounts for both regions.

2.6 Results - Denmark West

In this section we summarize the results for the Western part of Denmark. This region lies in the UCTE synchronous grid. Linked to the connection to Germany there is a Load Flow Controller (LFC) which automatically regulate a smaller part of the unbalance with low reaction time (this is sometimes called the secondary reserves). The large part of the imbalance is balanced by purchasing regulating power on the regulating power market. The real data for this market has been collected from Energinet:

- Bids: Bids from all power producers within each region in all hours.
- Planed flow: The planed flow on the interconnectors.
- Capacity: The capacity on interconnectors.

From the data the following data is calculated:

- Offered Upregulation per region = Sum of all bids within the region in each hour.
- Possible Upregulation per region = Offered Upregulation per region + Capacity of interconnectors - Planed flow on interconnectors.

The possible upregulation per region is used to compare to the demand for replacement reserves calculated by the STT. The result is shown in Figure 25.

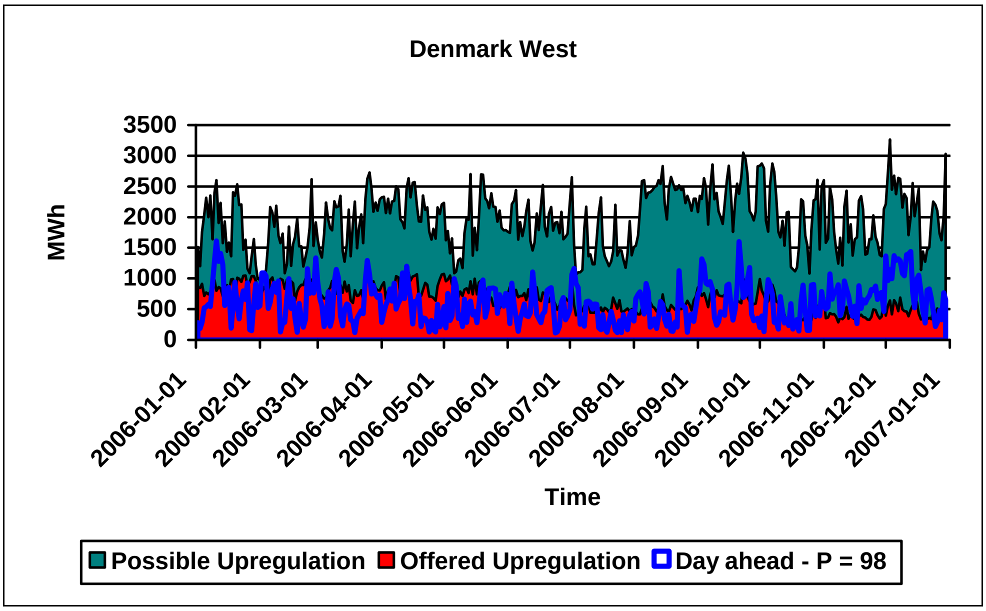


Figure 25 Daily average of demand for replacement reserves vs. Upregulation power

In Figure 25, we see that several times during the year, the TSO is in a situation where the offered regulating power fails to cover the demand for replacement reserves with a 98 percentile. The Possible Upregulation is only at one point slightly less than the 98 percentile. The capacity of the power producers is known by the TSO in every hour. In case the TSO is short of regulating power they ask the producers to put in more bids in the regulating power market. In the case that the capacity from these power producers is not enough the TSO has an opportunity to force exceeding available capacity into the market.

All the outliers of the demand for replacement reserves are smoothed by monthly averaging and plotted in Figure 26.

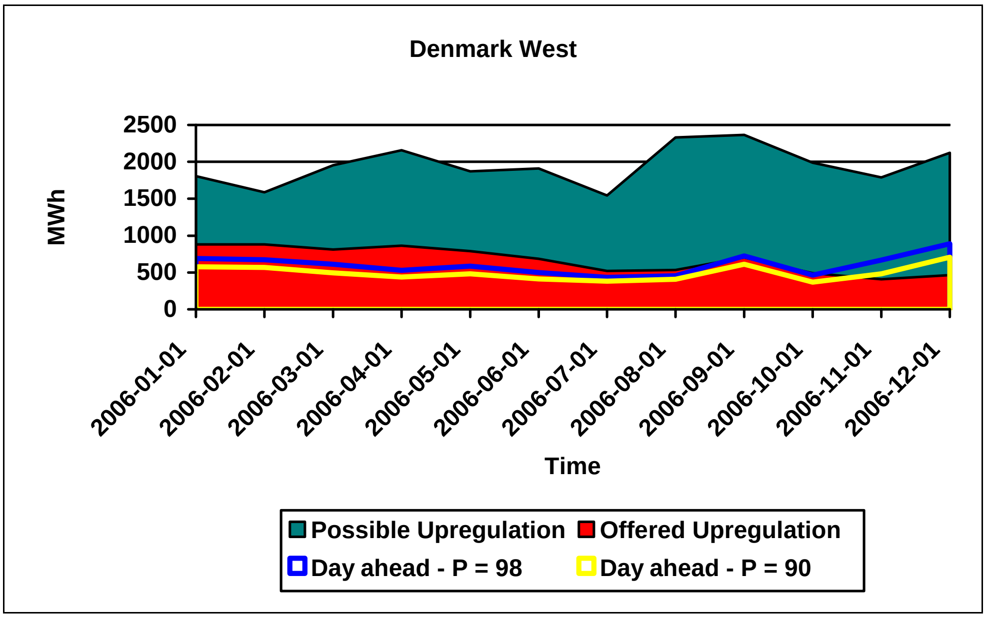


Figure 26 Monthly average of demand for replacement reserves vs. Upregulation power

Figure 26 show that the monthly average bids in the regulating power market (Offered Upregulation) covers the 98th percentile of the replacement reserves. So in general there is enough capacity in the market except for the last two month of 2006. In month nine and ten the Offered Upregulation is very close to the demand for replacement reserves with the 98th percentile. With further calculation it is possible to find the percentile where the monthly average of the demand for replacement reserves is exactly equal to the monthly Offered Upregulation. The monthly average Possible Upregulation covers the 98th percentile of the replacement reserves in all months.

The difference between the percentile of the demand for replacement reserves which cover the purchased Upregulation power and the percentile of the demand for replacement reserves which cover the Offered Upregulation, found to 98th in Figure 26, is investigated. The demand for replacement reserves which cover the purchased Upregulation power is below the demand for spinning reserves so the STT is used without this constraint. This is shown in Figure 27.

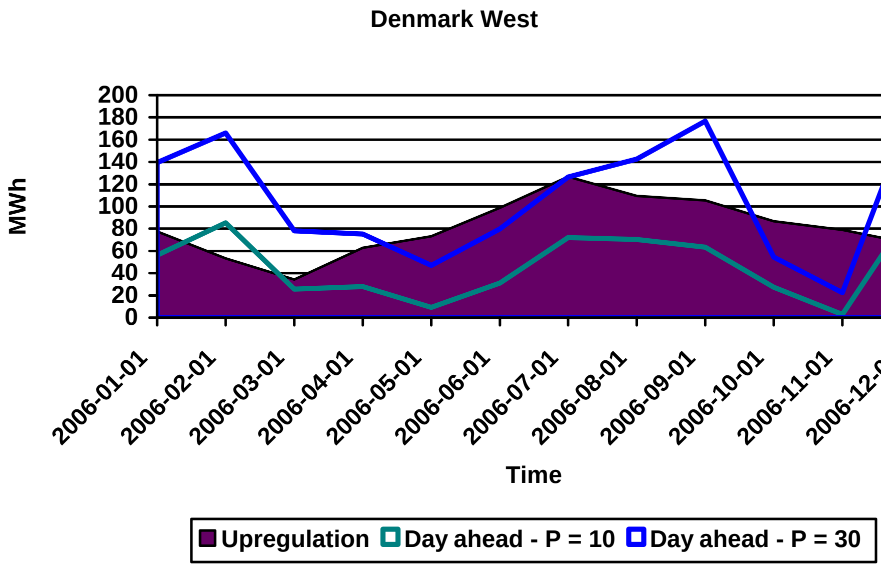


Figure 27 Monthly average of purchase Upregulating power

The 30th percentile is estimated, from Figure 27, as the percentiles where the demand for replacement reserves covers the purchased Upregulation power. As earlier it is possible to find a better solution for the percentile with further calculations.

The conclusion in this section is that the in Denmark West the demand for replacement reserve should calculates with a percentile no less than 30.

2.7 Results - Denmark East

The region lies in the Nordel synchronous grid. The balance in this region is primarily maintained by the Svenska Kraftnet (SvK) in Sweden. Only when there is a congestion problem, either internally in Sweden or between Sweden and Eastern Denmark, the region has to maintain its own balance. Even though they do not maintain balance all the time they contribute to primary reserves in the Nordel synchronous grid. There are no secondary reserves (LFC) and daily tertiary reserves are only bought if Sweden has internal electric technical problems. In addition Eastern part of Denmark has a long term contract (several years) of reserves standing by on a single power plant.

In Eastern Denmark we do not have all the bids in the regulating power market as we do have in the Western part of the country. If Eastern Denmark were to maintain balance the imbalance would be the optimal amount of regulating power to purchase. Therefore we choose to compare data for the system imbalance with the demand for replacement reserves with the 98th percentile like in Denmark West.

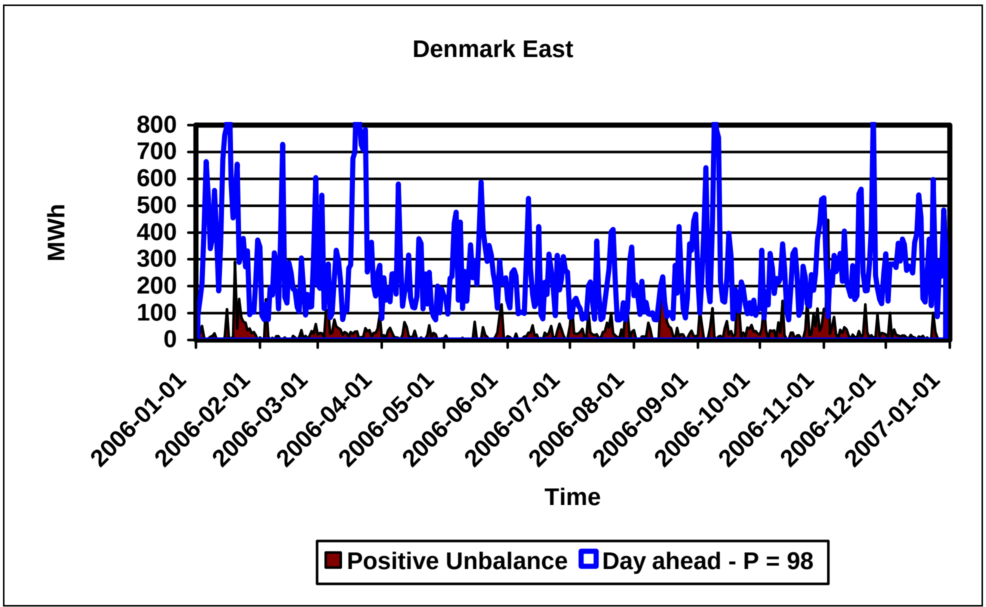


Figure 28 Daily average of demand for replacement reserves vs. Positive imbalance

We note, in Figure 28, that the demand for replacement reserves is much larger than the imbalance. In western part of Denmark the demand for replacement reserves with the 98th percentile was covered with the Offered Upregulation so it was expected that the demand for replacement reserves with same percentile would cover the offered upregulation in the eastern part of Denmark.

For the eastern part of Denmark the monthly averages is calculated like it was in the western part of Denmark, the result is shown in Figure 29. The demand for replacement reserves which cover the purchased Upregulation power is below the demand for spinning reserves so the STT is used without this constraint. This is shown in Figure 29.

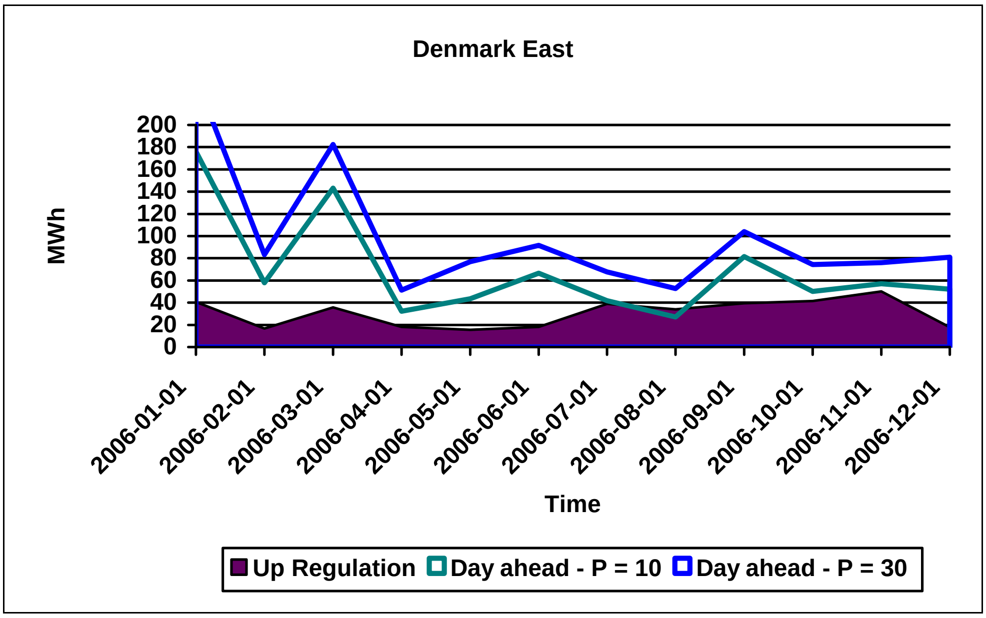


Figure 29 Monthly average of demand for replacement reserves vs. Positive imbalances.

The 10th percentile is estimated, from Figure 29, as the percentiles where the demand for replacement reserves covers the purchased Upregulation power. It is possible to argue that a lower percentile would be better with further calculations.

The conclusion in this section is that in the eastern part of Denmark the demand for replacement reserve should calculates with a percentile no less than 10. The 10th percentile is very low. The low installed wind power capacity can be the cause.

2.8 Conclusion

In Western Denmark it seems like the demand for replacement reserves indicates the offered up regulation. The replacement reserves in the model are calculated as the available capacity whereas the offered up regulation is the sum of all bids in the regulating power market. This seems like fair to compare these numbers even though we know that not all producers offer all their available capacity in the regulating power market. The TSO is, in fact, interested in getting an estimate of the available capacity (replacement reserves) rather than the amount of power offered in the regulating power market. This can of cause calculates from the demand for replacement reserves, the capacity on the interconnectors and the planed flow on the interconnectors.

3 Day-ahead optimization of tertiary reserves

The Danish case study presented in Chapter 1 provides a basis for analyzing the ability of the modeling tools to assist the TSO in day-to-day operation of the system. Being a very important part of that, this chapter places special emphasis on optimizing tertiary power reserves a day ahead of operation.

3.1 Introduction

In the Nordic countries, the TSO's are stateowned and non-commercial companies, responsible for the security of supply. In ensuring security of supply, the provision of power reserves is crucial. In the Nordic system, power reserves include primary, secondary and tertiary reserves and are also referred to as regulating power.

As already indicated in this report, demand for power reserves arises due to imbalances between power demand and supply expected at the time of planning and actually realized during operation. Within longer activation times, regulating power is provided through an organized market and activated manually. However, due to market imperfections, the power offered to the market may be insufficient unless contracted ahead of operation. Regulating power may therefore be contracted in advance, such reserves being referred to as contracted regulating power or manual power reserves.

The idea is to estimate the amount of regulating power to be contracted by the Danish TSO on daily auctions a day ahead of operation. The estimation procedure is based on the difference between social welfare optimization of the system and optimal scheduling of the producers, taking into account an imperfect market.

For other references on reserve estimation, see [Söder 1993, Landberg et al. 1994, Doherty and O'Malley 2005, Meibom et al. 2007] who determine reserves such as to maintain a reliability level at any costs and operate the system accordingly and [Bouffard et al. 2005, Wand et al. 2005] who optimize system operation by considering the tradeoff between reliability and the costs of reserves.

3.2 Power reserves

The Danish electricity system, part of both Organisation for the Nordic Transmission System Operators (Nordel) and Union for the Co-ordination of Transmission of Electricity (UCTE), divides reserves into frequency regulation, automatic regulation and manual regulation [UCTE 2004, Nordel 2007] in the following way:

- *Primary reserve/instantaneous reserve/frequency regulation:* Frequency regulation is required in both Nodel and UCTE to reduce the deviations in frequency that follow an instantaneous imbalance in the system. The frequency is stabilized at a stationary value that may be different from the nominal value. Frequency regulation is activated within a few seconds or minutes and the duration is at most 15 minutes.
- *Secondary reserve/automatic regulation*: Automatic regulation serves to restore the nominal frequency value according to the UCTE requirements. This type of reserve is automatically activated within a few seconds or minutes and usually stays active for 15 minutes.
- *Tertiary reserve/fast and slow reserve/manual regulation*: Tertiary reserves, required in both Nordel and UCTE, are used to manually restore their primary or secondary equivalents. This involves optimization of both operation and transmission which results in longer activation and duration times. Accordingly, tertiary reserves are activated within approximately 15 minutes by starting up and shutting down generators, redistributing between generators, and changing exchange levels.

Restricting attention to a time resolution in the order of an hour, the focus is tertiary reserves only. Since the estimation of demand for primary and secondary reserves calls for significantly shorter time resolutions, contributions from the literature tend handle such reserves differently, see e.g. [Feltes et al. 1999, Lin et al. 2007].

3.3 Tertiary reserves

To ensure security of supply when having already activated frequency regulation and automatic regulation, the Danish TSO activates manual regulation. Up-regulation is activated if supply is insufficient to fully meet demand and down-regulation if the contrary applies. Activation takes place through a Nordic regulating power market. However, sufficient capacity may not always be directly available in the market and often has to be contracted prior to activation. In Nordel manual regulation therefore divides into market-based regulating power and contracted regulating power, also referred to as manual power reserves. Market-based regulation is activated during operation and provided through the regulated power market, paying the regulating market price. Previously, manual reserves were solely contracted bilaterally for a year or longer. The bilateral contracts have been kept for the purpose of reducing investment risk for market entrants but the total volume is presently limited. Now daily auctions for manual reserves have been introduced. Considering contracting as optioning, contracted regulation is paid an option price on the daily auction for ensuring available capacity day-ahead. Upon activation, producers are obliged to offer the regulating power to the market in same the fashion as for market-based regulation. From a social welfare perspective, regulating power should be sufficient during operation and thereby directly available in the regulating power market, uncovered imbalances being highly expensive. Nevertheless, insufficiencies occur if the producers lack incentive to produce it in spite of a social value. This lack of incentive is handled within the system by contracting ahead of activation and paying the social value of security of supply. Assuming no bilateral contracting, the aim of this chapter is therefore to estimate the amount of manual reserves to be contracted by the Danish TSO on daily auctions a day ahead of operation. Although based on the Danish electricity system and the Nordic power markets, the following will apply to any other system organized in a similar fashion, e.g. the Norwegian.

3.4 The estimation procedure

The Nordic electricity system operates with a day-ahead and two intra-day markets. The day-ahead market Elspot is a spot market established for the delivery of power from producers to consumers and in which commitments are made a day in advance. The two intra-day markets comprise the aftermarket to Elspot, Elbas, and the regulating power market. Unlike in Elspot and Elbas, the system operator activates supply and demand offers made by producers and consumers in the regulating power market. Although the day-ahead market aims at balancing supply and demand, real-time imbalances may still occur between power demand and supply expected at the time of planning and actually realized during operation. This may involve contingencies caused by forced outages of generating units and failures of transmission lines as well as discrepancies that result from unpredicted variations in demand and notably wind power. A rebalancing of supply and demand is possible through the aftermarket. However, since historical records reveal a limited volume exchanged in the aftermarket we do not consider this market but assume a spot and a regulating power market.

Since need for manual reserves arises due to unexpected imbalances, the modelling takes into account uncertainty. This is done on the basis of the Scenario Tree Tool. Being the main sources of uncertainty, we consider only wind power forecast errors and forced outages of the generating units. The stochastic process of forecast errors and forced outages is described by a discrete distribution with a finite number of realizations referred to as scenarios and generated by sampling. The number of scenarios obtained by sampling should be sufficient to approximate the true distribution of forecast errors but feasible for computations. The idea is therefore to generate a large set of Monte Carlo samples and reduce the set by clustering, at the same time inducing a tree structure and loosing as less information as possible. For further reference, see Chapter 1. By construction, the scenario reduction tends to remove extreme scenarios. However, as extreme scenarios may have a significant impact on the amount of manual reserves necessary, the scenario tree have been enhanced by including not only the scenario closer to the remaining scenarios but additionally an upper tail percentile from the distribution of each cluster.

The modelling setup is based on the Scheduling model for unit commitment and dispatch in a day-ahead and an intra-day market. Unit commitment takes place a day-ahead of operation. Since market-based regulation is to be immediately available it is provided by fast-starting units and by idle online capacity from slow-starting units dispatched in the spot market. In contrast, contracted regulation may be obtained from both slow-starting and fast-starting offline and online units.

The procedure for estimating the amount of manual reserves is based on the difference between social welfare optimization of the system and optimal scheduling of the producers, taking into account an imperfect market. As an attempt to reflect the imperfection of the regulating power market it is assumed that producers schedule unit commitment and dispatch, considering the day-ahead market only and ignoring the regulating power market. The procedure for estimating the amount of manual reserves necessary to contract by the TSO is the following:

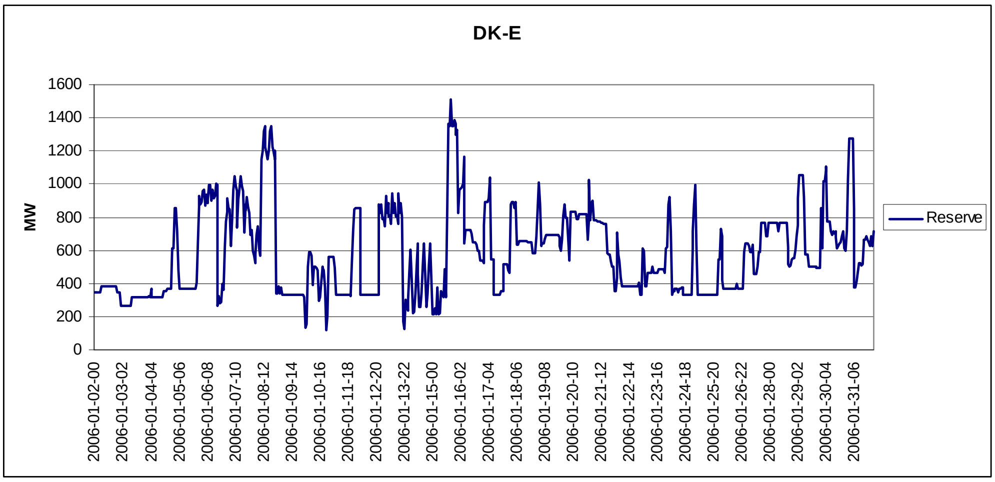
1. Run the Scheduling Model without the regulating power market and store the capacity of online units scheduled for the following day. Producers start up capacity for spot market dispatch, ignoring the regulating power market. The resulting capacity may be insufficient for power balancing.
2. Run the Scheduling Model and store capacity of online units scheduled for the following day. From a system perspective, producers should start up capacity for spot market and regulating power market dispatch such as to ensure sufficient capacity for power balancing.
3. The difference in online capacity has to be contracted ahead of operation for producers to start up sufficient capacity. Moreover, producers offer idle online capacity as contracted regulating power. Hence, estimate the amount of manual reserves as the sum of insufficient and idle online capacity.

The estimation procedure applies to day-ahead planning of manual reserves. To optimize reserves throughout longer time periods, the procedure can be used in a rolling planning fashion. The model is rerun when information, e.g. forecasts of wind power and forced outages, is updated such that the first run, from 12.00 and 36 hours ahead, will carry out day-ahead planning of manual reserves whereas the remaining runs, e.g. from 18.00 and 30 hours ahead, will update the status of the system prior to day-ahead planning. The rolling planning is described in Chapter 1.

3.5 Computational results

Based on the implementation of the Scheduling model, the estimation procedure has been implemented in GAMS and tested on the Danish case study. Preliminary results are given for January 2006.

Figure 30 shows hourly amounts of manual reserves for Eastern and Western Denmark. In contrast to long-term contracts, daily auctions allow for the amounts to vary over time which is utilized in both regions.



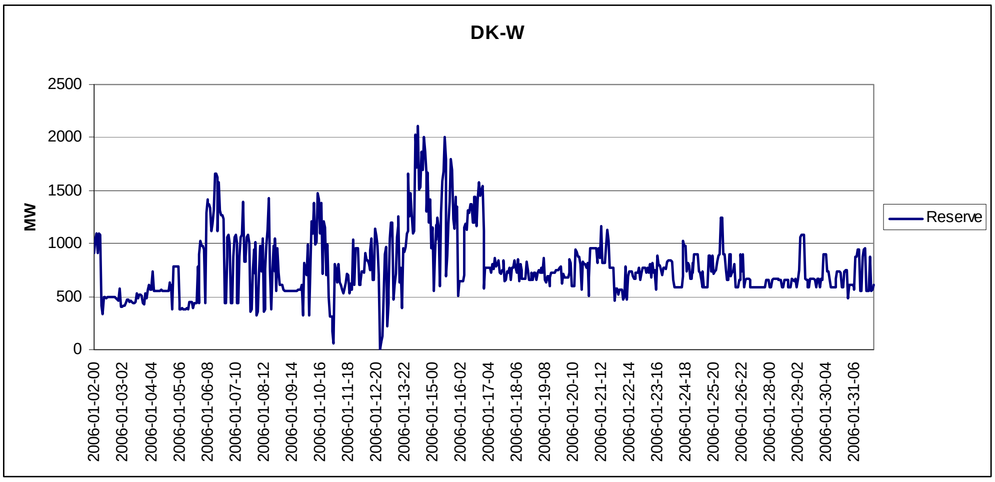
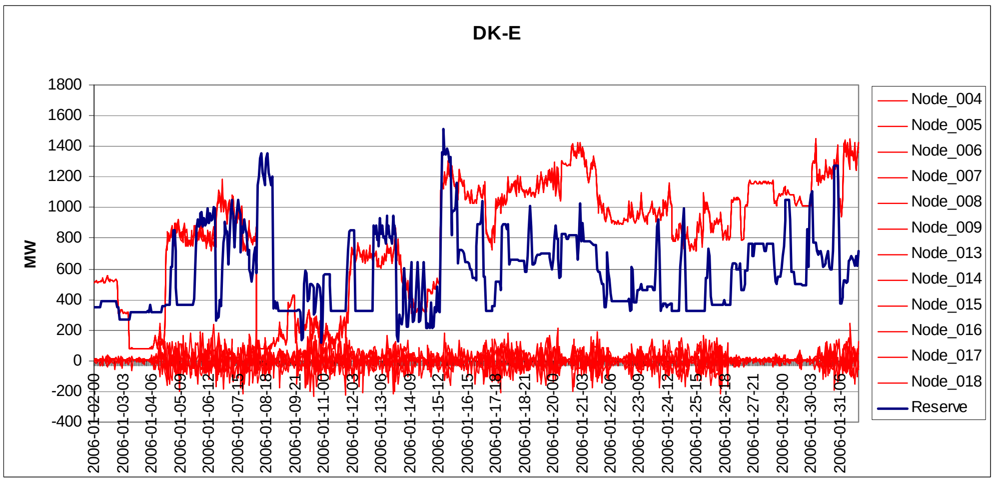


Figure 30 Manual reserves for Eastern and Western Denmark. January, 2006.

As system imbalances are covered by regulation (as well as import and export), the amount of contracted regulation tend to be larger the larger imbalances. However, contracted regulation often exceeds average imbalances in order to cover part of more extreme imbalances. This is evident from Figure 31. As can be seen, the dependency of contracted regulation on average imbalances is small whereas the amount of contracted regulation is clearly larger the larger the most extreme imbalances. Mostly, the amounts are substantially larger in Western than in Eastern Denmark, reflecting larger variance of imbalances caused by a larger installed wind capacity in the region.



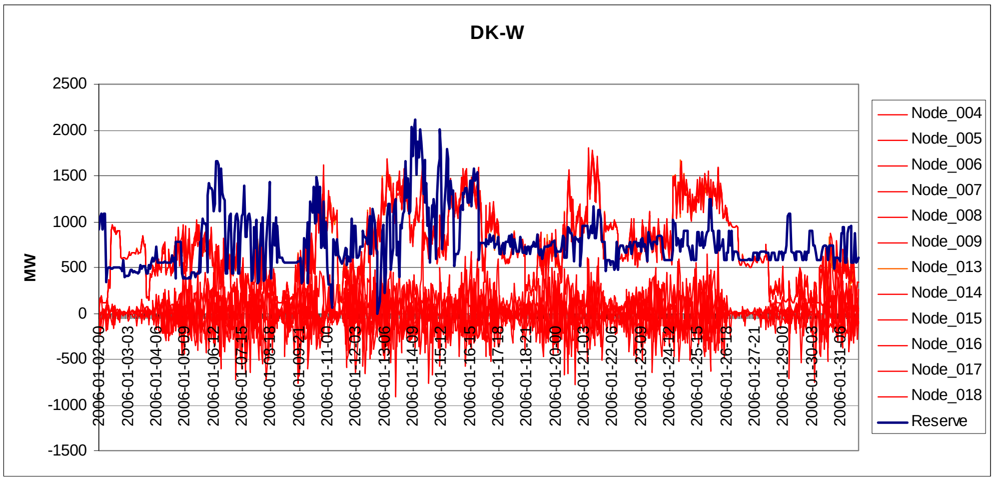


Figure 31 Manual reserves and the distribution of forecasted system imbalances. January, 2006.

4 Conclusions

The present report serves to analyze the ability of the modeling tools in Supwind WP7 to assist in day-to-day operation and planning of a power system, with special emphasis on day-ahead scheduling and in particular the estimation of power reserves. The analysis is based on a Danish case study.

The modeling tools of Supwind have been adapted to reflect the operation of the Danish TSO as closely as possible. Thus, the Scenario Tree Tool has been enhanced to comply with both the forecast and the forecast accuracy of the Danish TSO, taking into account updated load and wind power forecasts and forced outages of the units. The Scheduling Model has been improved such as to illustrate the way of updating this information by the Danish TSO, changing the looping structure. Moreover, the model has been extended to allow for mixed-integer modelling of the most important Danish units and linear modelling of the remaining units.

The results of using the modelling tools for day-ahead scheduling have been compared to historical data for Denmark, concentrating on transmission flows. The results suggest that further calibration would be valuable, using the direction of transmission flows to adjust water values and fuel prices.

The estimation of power reserves is made on the basis of the modelling tools, applying two difference approaches. One approach determines reserves such as to cover system imbalances simulated by the Scenario Tree Tool. Using these imbalances as input to the Scheduling Model, the other approach determines reserves by considering the difference between optimal scheduling of the power system and the producers.

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