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Wind-induced Day-Ahead and Hour-Ahead Imbalances in a Power System with a Significant Wind Mix: The Danish Experience

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Abstract

We describe the wind forecast module that is a component of the Simulation of Balance (SimBa) software being developed by the Danish transmission system operator (TSO), Energinet.dk to assist in the day-ahead and hour-ahead balancing and scheduling of the entire power market system in Denmark. We interpret the wind-induced imbalances as the error E between the forecasts F and the measured available power P. The forecasts and power measurements are from Energinet's records for the onshore wind data from the late 2009 until 2011 and is aggregated into two sets representing the western (DK1, 2400 MW) and the eastern (DK2, 585 MW) Denmark. The Gaussian fit of the probability distribution and the slow decay of autocorrelation function of the measured forecast error E together suggests that an autoregressive moving average (ARMA) model is appropriate. We estimate the ARMA parameter set with the least mean absolute error (MAE) and use this to calculate the available installed power P_{DA} and the hour-ahead forecasts F_{HA} for the entire day of operation. These are calculated in sequence from the input day-ahead forecast, F_{DA}. We also describe the procedure for tuning the horizon of the error series from the daily market closure time and the update times of the meteorological wind speed forecasts. Based on the mean absolute error (MAE) of the forecasts, we find that the simulated forecasts errors mirror the measured forecasts error at the 4.9/5.3% level for DK1/DK2. For the hour-ahead case, the values for the (offline) simulated error is 7.1%/5.2 % for DK1/ DK2, while the values for the measured error is 2.0%/3.3 % for DK1/ DK2, with the discrepancy given approximately by the day-ahead levels for each area. On the average, the spread of the hour-ahead MAE is no more than 0.1%.

I. Introduction: The SimBa Motivation

As Denmark spearheads the global effort in developing wind energy as a veritable option to fossil fuels, it also finds itself at the forefront of confronting the accompanying challenges of integrating wind power into the grid. The Danish power system is characterized by a high wind contribution that is estimated at 22% in 2010[1] and is targeted to hit 50% in the year 2020[2]. This is in line with the Danish government's commitment in 2011 to a fossil-fuel-free Denmark by the year 2050[3].

To address this high wind penetration challenge in part, the Danish transmission system operator (TSO) Energinet, is developing SimBa[4] to aid in quantifying the imbalance that wind production can introduce into the Danish power system. There are already available a number of approaches and methods that suggest how to incorporate wind production forecasts at the system level. Among these approaches, SimBa is unique in the sense that it is geared towards real time balancing. SimBa is pioneering the effort to simulate the balancing of the production and consumption at the intra-hour scale, and it does this for a system with a characteristically significant wind portion.

We relate the challenge of balancing power in a system with high wind mix into a series of tasks that is facing the workers in a control room. A day before the operation, controllers need to establish the unit commitments. In a liberalized power market like in Denmark, the schedule for doing this is tied to the market schedule. The gate closure time for putting in bids or commitments to the day-ahead production and consumption is at 12noon. This market schedule imposes 12 to 36 hour horizon requirement for any tool that is used to forecast the day-ahead available power from wind farms.

No forecasting tool is perfect. In general, the forecasting error increases with time. At the start of the day-of-operation, at least 12 hours would have lapsed since the day-ahead projections are laid down. Such projections would have deviated from actual power measurements. Forecasting errors directly translate into system imbalances, if not kept in check. In order to keep the system in balance, it is then necessary to update the day-ahead forecasts using all available data before the hour-of-operation starts, including data that was gathered after the gate closure time when the day-ahead forecasts was done. For the controllers at Energinet, this happens 30 minutes before the start of the hour of interest. The controllers at Energinet faces a balancing act that operates in two characteristic horizons corresponding to two sets of tasks; the unit commitment tasks, which has the day-ahead horizon between 12 to 36 hours, and the balancing and regulation, which has the hour-ahead horizon between 30 to 90 minutes. In the same vein, we developed the forecast module as described in this report with two objectives. The first objective is to provide a day-ahead forecast of the available power from the wind farms and the second objective is to provide an hour-ahead adjustment to these power forecasts in time for the start of the hour of operation.

II. Overview of the SimBa Forecast Module

We propose a statistical approach in calculating the objective series of the forecast module. The object of the forecast module is to calculate the following time series that applies to the day of operation.

1. The Day-ahead Available Power Time Series P_{DA} (in 5 minute resolution)
2. The Hour-ahead Forecasted Power Time Series F_{HA} (in 5 minute resolution)

The input to the module is the hourly power values that were forecasted within the day before the operation. As no forecasting tool is perfect, the input forecast values will tend to deviate from the actual values and these deviations or errors will tend to increase further into the horizon. We assume that within a day, the error evolves like an autoregressive and moving average (ARMA) process. We further assume that just a single process is relevant to both the day-ahead and the hour-ahead error calculations, albeit with a change in the relevant horizon.

The method starts with the input from the unit commitment (UC) module. This is a series of hourly day-ahead forecasts values, F_{DA}, for the power produced by an aggregated wind farm unit. The first objective is to calculate the available power, P_{DA}. This is simply;

$$P_{DA} = F_{DA} - E_{DA} \qquad (1)$$

Although the installed generating capacity is not expected to change drastically from day to day, the power that is available in any particular day can change due to random events (e.g. faults and storm shutdown) and systematic causes (e.g. regular maintenance). To incorporate the changing availability of power from day to day, we scale E_{DA} by the amount of capacity available for the day to obtain the per unit error ε_{DA} as

$$\varepsilon_{DA} = \frac{E_{DA}}{I_M} \qquad (2)$$

where I_M is the available capacity that is taken to be fixed for an entire day. Hence, in order to calculate P_{DA}, we need to generate an expression for E_{DA} through ε_{DA}. Inside the forecast module, the ε_{DA} series is provided by an ARMA process generator.

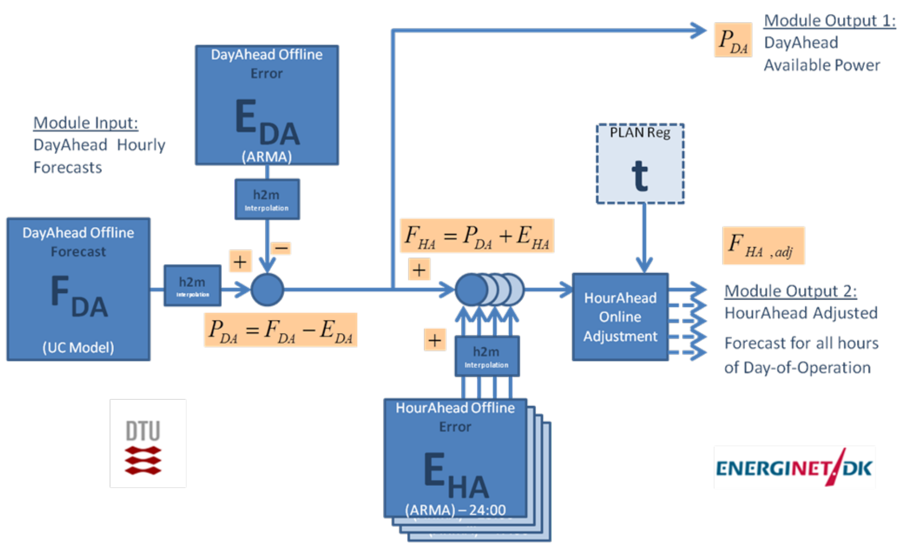

Figure 1 The input to the forecast module is the hourly day-ahead wind power forecasts, F_{DA} , from the unit commitment (UC) model. The forecast module of SimBa is configured to calculate the day-ahead (DA) available power, P_{DA}, and the hour-ahead (HA) forecasted power, F_{HA}, for the power output from wind farms in the Denmark, aggregated into two main areas: the DK1 (western) and DK2 (eastern).

To calculate the hour-ahead power forecasts F_{HA}, we adjust the initially calculated P_{DA} with an error series E_{HA} that has an hour-ahead horizon, as

$$F_{HA} = P_{DA} + E_{HA}. \qquad (3)$$

Similar to the day-ahead errors, we deal with the error per unit ε_{HA}, defined as

$$\varepsilon_{HA} = \frac{E_{HA}}{I_M}. \qquad (4)$$

To simplify the calculation of the hour-ahead forecasted power, we assume that the hour-ahead error is generated by the same process that gives rise to the day-ahead errors. This means

ε_{HA} can be generated using the same ARMA parameters that characterizes ε_{DA} but with the horizon tuned to just an hour ahead, i.e.

$$\varepsilon_{HA} = \varepsilon_{DA \to HA} \quad . \qquad (5)$$

The core of the forecast module is the proper generation of the per unit error series ε , at the appropriate horizon as required of the output.

The scheduling and balancing tasks at Energinet require that the output series have a 5 minute resolution. We generate the higher resolution output series by a simple linear interpolation of the hourly values. In the future, the interpolation can be implemented using other statistical or physical models for the expected intra-hour values.

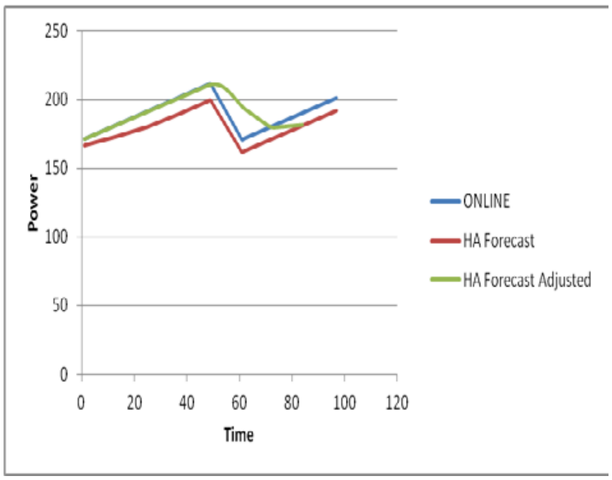

Figure 2. A sketch of the adjustment algorithm. The blue ONLINE is the measurement while the red HA Forecast line is the available forecast. The green HA Forecast Adjusted line reconciles the measured and forecasted power series.

To mimic the actual hour-ahead forecast calculations that are being done in Energinet's control room, the hour-ahead forecasts values F_{HA} are passed on to an adjustment algorithm that reconciles the most recently available measured power values to the most current forecast values. We show in Figure 1 that this adjustment algorithm precedes the output of the hour-ahead forecasts, with a result that is labelled as $F_{HA,adj}$. The basic idea behind the adjustment algorithm is shown Figure 2. The ONLINE series represents the power measured before the hour of operation while the HA Forecast series is the hour-ahead forecast calculated by the forecast module. Using a simple weighting procedure, the ONLINE series is combined with the HA Forecast such that within the hour of operation, the adjusted series matches the ONLINE measurements in the beginning and then slowly matches the HA Forecast towards the end.

III. The Tuning of the Horizon for Day-Ahead and Hour-Ahead Calculations

We also describe the procedure for tuning the horizon of the error series from the daily market closure time and the update times of the meteorological wind speed forecasts.

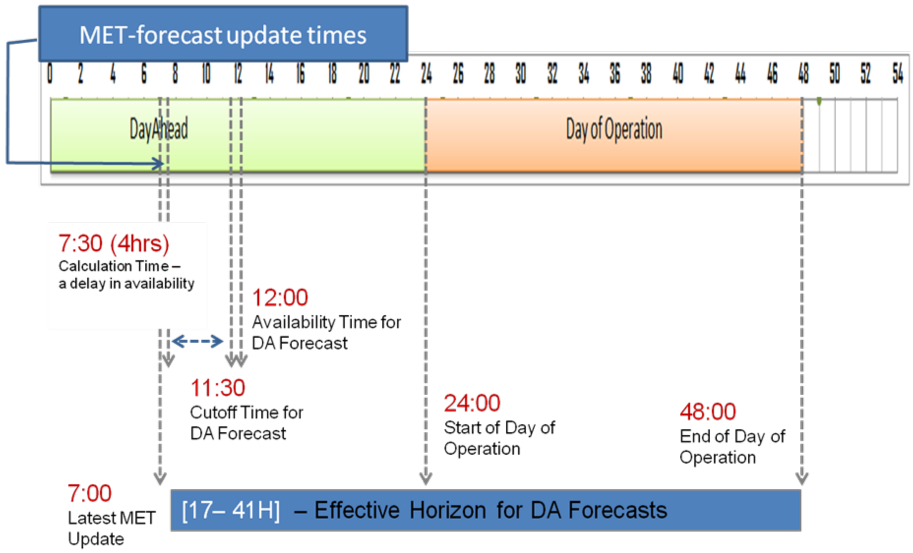

Figure 3. The horizon for the day-ahead forecasts takes into account the market/bidding closure time, power forecast calculation time and the meteorological update times. The effective horizon is in the range of 17-41 hours.

The power forecasts by Energinet are based on the meteorological (MET) speed forecasts that are released every day on the hours UTC {0,6,12,18}. In Denmark, which is in the UTC+1 time zone, the corresponding hours are at CET {1,7,13,19}.The cutoff time for the release of the day-ahead forecasts is at 11:30 AM (market schedule). Energinet uses a few forecasts based on different numerical weather prediction (NWP) models. From the combined NWP models, the power output is calculated via an assumed power curve. This calculation introduces a delay of about 4 hours in the update of power forecasts . Hence, the calculation of the day-ahead forecasts at cutoff time 11:30AM are initiated as early as, for example 7:30 AM. At 7:30AM during winter times, the most recently available MET forecast is released at 7AM. From 7AM until the day of operation, the horizon is effectively in the range of 17-41 hours. The day-ahead horizon can vary for the summer time, because the market schedule follows the summer time. Hence, the MET forecasts are released at hours CEST{2,8,14,20}. For this work, we use only the data with the winter time stamps. A similar horizon tuning step is done for the hour-ahead calculations, whereby the cut-off time is 30minutes before the hour of operation. The effective horizon is in the range of 5-10 hours.

IV. Results

a. Error as an ARMA process

The proper generation of the per unit error series ε is central to the forecast module. It relies on the *a priori* characterization of ε from available data. The characterization of ε as an ARMA process is not part of the forecast module. But the results of this characterization, which are the ARMA parameter estimates for the two types of aggregate wind farm units, is embedded in the forecast module. It is crucial to get these estimates right.

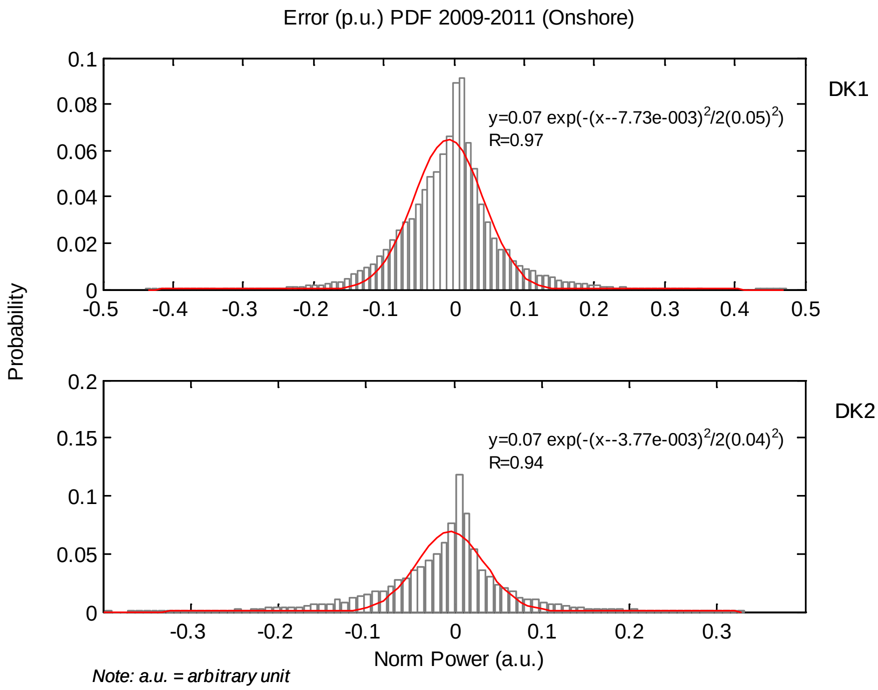

Figure 4. The probability density function (pdf) for the error (p.u.), when fitted with a Gaussian function, has fit correlation coefficient of R=0.97 / R=0.94 for the DK1/DK2.

ARMA[5] stands for the autoregressive and moving-average method that is used to describe processes wherein the current value of a particular state variable depends on its previous values (AR part) and the previous values of random terms (MA part). As such, it has become a standard technique in forecasting tasks. In this work, the ARMA model that we use to characterize the error series is described by the following equation;

$$\begin{aligned} &\varepsilon(0)=0 \\ &Z(0)=0 \\ &\varepsilon(k)=\alpha\,\varepsilon(k-1)+Z(k)+\beta\,Z(k-1) \end{aligned} \tag{6}$$

Where

$\varepsilon(k)=$ error (p.u.) value at the k-th hour of the forecast

$Z(k)=$ random Gaussian variable with standard deviation σ_z

$\alpha, \beta =$ parameter of the ARMA-series.

The day-ahead error series ε_{DA} and ε_{HA} can be interpreted as;

$\varepsilon_{DA}=\varepsilon(k_{DA})$, where $k_{DA} \in$ {the times of the day-ahead}

$\varepsilon_{HA}=\varepsilon(k_{HA})$, where $k_{HA} \in$ {the times of the hour-ahead}.

Using an estimation procedure based on maximum likelihood[6], we estimate the values for the ARMA parameters α and β as well as the parameter σ_z for the Gaussian random variable. Using the data available for 2009-2011, we estimate the needed parameters for the error characterization for the two sets of aggregate wind farm units, i.e. the DK1and DK2. The parameters set that give the smallest mean-absolute-error (MAE) against the data for all the days considered, is passed on to the ARMA process generator inside of the forecast module.

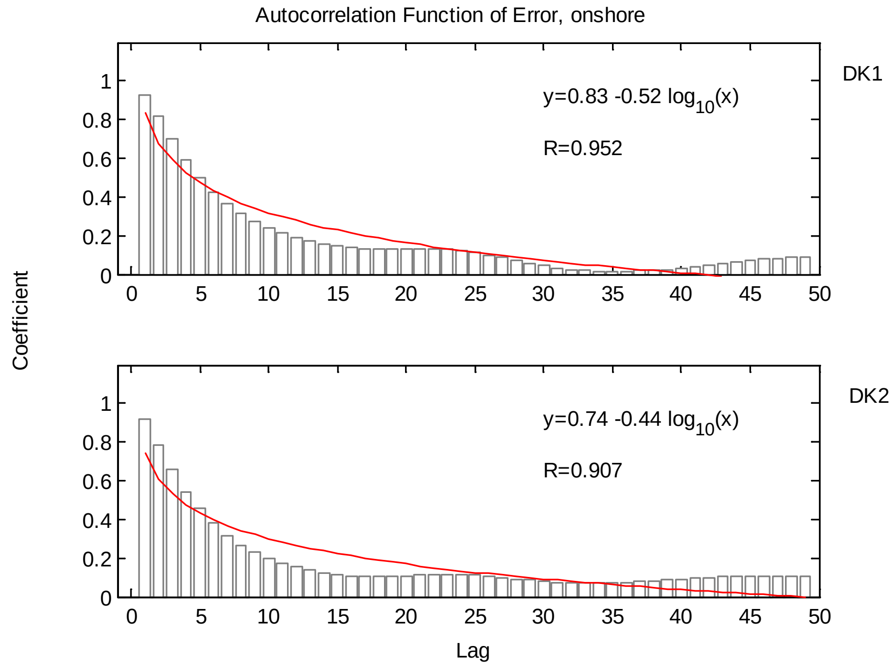

Figure 5. The autocorrelation function of the error (p.u.) has a decay that is slower than an exponential function, for both DK1 and DK2.

We try to justify the applicability of the ARMA model in characterizing the error series. In order to this, we show that [7]:

1. *Gaussian distribution assumption*: The Gaussian probability density function (pdf) should fit well the probability distribution of the ε (p.u.) time series. This is clearly shown in Figure 3.

2. *Slow-decay for autocorrelation assumption:* The autocorrelation function of ε must approach zero with a decay that is slower than an exponential function. As shown in Figure 4, the autocorrelation function for the error series decays logarithmically. If the decay is exponential, then the error series can be sufficiently described by an autoregressive (AR) model. A slow decay suggests that a mixed autoregressive and moving average, i.e. the ARMA model, is more justified.

With regards to the question of which order of the ARMA model to use, there are criteria available that can be used to decide on this. For this work, we choose the parsimonious model that is ARMA(1,1) and we show that as far as the MAE performance is concerned, that this choice is reasonable.

b. Mean Absolute Error (MAE) for the DA and HA

Based on the MAE, the simulated errors mirror the level in the actual, measured errors, with an average of 4.9% for DK1 [Figure 6] and 5.2% for DK2 [Figure 7]. For the hour-ahead case, the values for the simulated error is 7.1%/5.2 % for DK1/ DK2, while the values for the measured error is 2.0%/3.3 % for DK1/ DK2. The discrepancy is due to the fact that current version of the forecast, which is still in the OFFLINE mode and assumes no updated measurements as inputs, the MAE of the hour-ahead forecasts is indexed to the MAE of the day-ahead forecast errors. Note that the discrepancy is given approximately by the day-ahead levels. In the actual version, there is a possibility for online operation, and so these hour-ahead values are expected to converge.

	Day-ahead Average		Hour-ahead Average	
	Meas	Sim	Meas	Sim
DK1	0.049	0.049	0.020	0.071
DK2	0.052	0.053	0.033	0.073

Table 1 Comparison of the average for the mean-absolute(MA) of the forecast errors for DK1 and DK2, for the day-ahead and hour-ahead cases and for the measured and simulated series.

The sawtooth-like feature of the F_{HA} output series is due to the online adjustment that Energinet implements on its online forecasts. Every hour, a given forecast is adjusted to begin at the most recently obtained power measurement and to slowly merge with the rest of the forecast. This is consistent with the sawtooth-like feature of the measured hour-ahead errors as well. For both the power areas, on the average, the spread of the hour-ahead forecasts is not more than 0.1%.

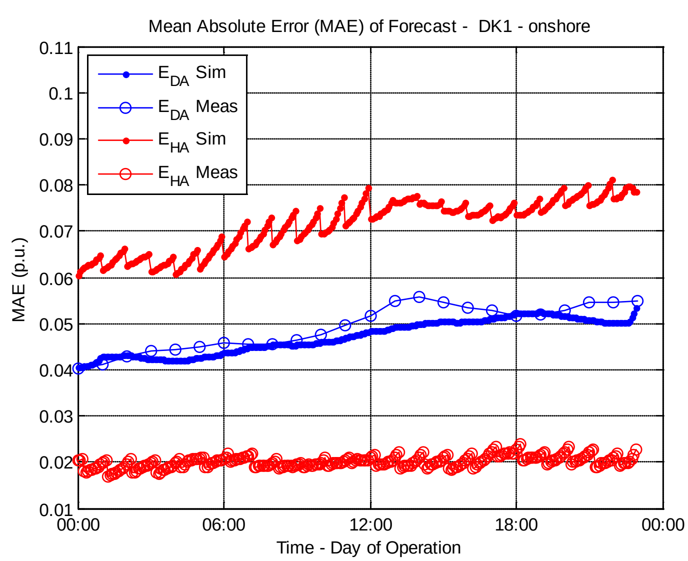

Figure 6. For DK1, a comparison mean-absolute of the simulated forecast error for the day-ahead and hour-ahead cases against the mean-absolute of the measured forecast error.

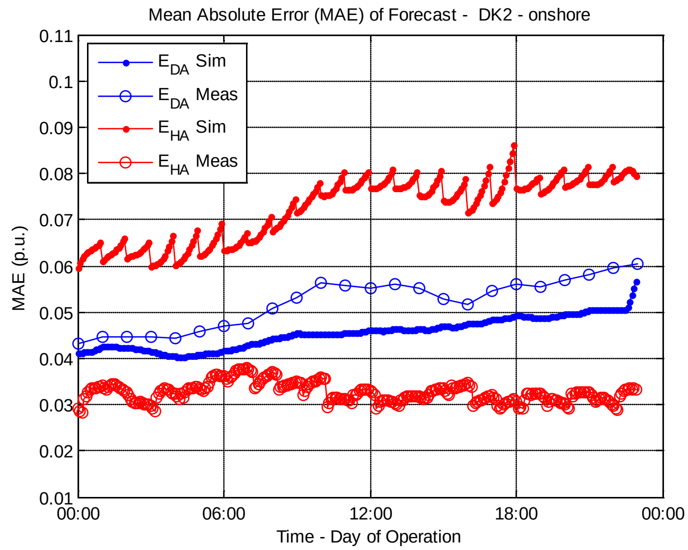

Figure 7. For DK2, a comparison mean-absolute of the simulated forecast error for the day-ahead and hour-ahead cases against the mean-absolute of the measured forecast error.

V. Conclusions

To implement the forecast module of SimBa, we propose a procedure that is based mainly on a single ARMA model of the error between the forecasts and the measurements of the wind power production in Denmark (late 2009-2011, winter times).

We justify the use of the ARMA(1,1) process to model the error series by showing that its probability distribution is fitted well by a Gaussian function and that its autocorrelation function has a slow logarithmic decay to zero. We assume that the same process is relevant to both the day-ahead and hour-ahead calculations via a suitable tuning of the error horizon.

Using a single error model tuned to the relevant horizon, we calculate the two output series of the module in sequence. In particular, we use the day-ahead version E_{DA} of the error model to estimate the available wind power P_{DA} from the given day-ahead power forecasts F_{DA}. Next, we use the hour-ahead version E_{HA} of the same error model to estimate the hour-ahead forecast series F_{HA} from the previously estimated available wind power P_{DA}. We also describe the procedure for tuning the horizon of the error series from the daily market closure time and the update times of the meteorological wind speed forecasts.

Based on the mean absolute error (MAE) of the forecasts, we find that the simulated forecasts errors mirror the measured forecasts error at the 4.9/5.3% level for DK1/DK2. For the hour-ahead case, the values for the (offline) simulated error is 7.1%/5.2 % for DK1/ DK2, while the values for the measured error is 2.0%/3.3 % for DK1/ DK2, with the discrepancy given approximately by the day-ahead levels. On the average, the spread of the hour-ahead MAE is no more than 0.1%.

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