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How predictable is DNI? An evaluation of hour ahead and day ahead DNI forecasts from four different providers

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Abstract. Forecast DNI values in hourly resolution for one day ahead are evaluated by a comparison with pyrheliometer ground measurements. Three months of such day ahead forecasts from four different providers for a site close to Questa, NM, USA are analyzed firstly by calculating the RMSE and the mean bias error. Secondly, cumulative distributions of the DNI forecast errors are calculated as they better suit the context of a utility's use of the forecast. Hour ahead forecasts are only briefly adressed due to the high uncertainty linked to these forecasts.

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INTRODUCTION

The anticipated strong capacity growth of CPV power plants in the next years [1] is likely to entail a growing demand for short term power forecasts. Especially for utilities with a high share of variable energy resources like CPV, hour ahead (HA) and day ahead (DA) forecasts are important for managing electric energy markets and for load balancing [2].

Because output from a CPV plant is roughly proportional to direct normal irradiance (DNI), error in a DNI forecast is a useful surrogate for error in a power forecast. This paper compares ground measured DNI to HA and DA forecasts from four different forecast providers (FPs) for a site close to Questa, NM, USA during a three months test period from October to December 2011. All four FPs provided DA forecasts. FP1 and FP2 additionally provided HA forecasts. The forecasts are validated in two steps: First, the error measures RMSE (root mean square error) and BIAS (the systematic error of the estimated DNI) are compared. Second, the cumulative distribution of error is calculated as it fits better in the context of utility planning. Finally, an overall comparison of the forecast providers is given.

DATA ACQUISITION AND PROCESSING

DNI ground measurements

The DNI was measured with a Kipp & Zonen first class pyrheliometer mounted on a Soitec CX-T010 tracker. Periods of non-tracking (e.g. due to wind stow) and periods of snow coverage of the pyrheliometer were removed. Mean DNI values for five minute intervals (for HA evaluation) and hourly intervals (for DA evaluation) were calculated by applying the trapezoidal rule on the raw DNI values.

DNI forecasts

Three months of DNI data measured prior to the test period were provided to the FPs to allow for improvement of the forecast algorithms by using MOS (Model Output Statistics, typically a set of multi-linear regressions applied to the raw output of numerical weather prediction models). During the test period the forecast DNI was obtained from the FPs in hourly (HA forecast) and daily (DA forecast) intervals.

FORECASTING TECHNIQUES

Most FPs were reluctant to give details on their forecasting techniques. Numerical weather prediction and satellite imagery were used for the DA forecasts. Sky imaging cameras for HA forecasts were found to be still in R&D state and were therefore not deployed. FP1 and FP2 could have used persistence algorithms as an additional technique for the HA forecast as the measured DNI was made available to these FPs almost in real time (five minutes delay). However the received HA forecast data suggests that persistence was not used.

DAY AHEAD FORECAST EVALUATION

Part 1:
Usage of RMSE and BIAS for evaluation

RMSE and BIAS provide overall measures of forecast performance. DNI ground measurements and DA forecasts from all four FPs were found to be fully available on 70 days of the three months test period. Only these valid days were analyzed and only the forecast given for one day ahead was considered. The valid days were categorized into three groups according to their daily mean DNI:

- 41 clear sky days with a mean DNI above 700 W/m²
- 20 variable days with a mean DNI between 200 W/m² and 700 W/m²
- nine overcast days with a mean DNI below 200 W/m²

RMSE and BIAS were calculated for all daylight hours of the valid days and are given in Table 1.

TABLE 1. Measured DNI and error measures for DNI forecast one day ahead given in W/m².

All days (70)	Mean DNI	RMSE	BIAS
Measured	648		
FP1	802	363	153
FP2	616	312	-32
FP3	784	352	136
FP4	753	316	104
Clear sky days (41)	**Mean DNI**	**RMSE**	**BIAS**
Measured	822		
FP1	851	223	29
FP2	692	258	-130
FP3	818	190	-5
FP4	870	215	48
Variable days (20)	**Mean DNI**	**RMSE**	**BIAS**
Measured	522		
FP1	788	457	266
FP2	567	346	45
FP3	771	434	249
FP4	710	435	188
Overcast days (9)	**Mean DNI**	**RMSE**	**BIAS**
Measured	73		
FP1	585	599	513
FP2	352	449	279
FP3	650	642	578
FP4	267	404	194

The daily values of RMSE and BIAS are shown in Figure 1 for the clear sky days, in Figure 2 for the variable days and in Figure 3 for the overcast days. To illustrate the differences between the FPs on an hourly basis on one example day, daily curves are shown in Figure 4 for a cleary sky day, in Figure 5 for a variableday and in Figure 6 for an overcast day.

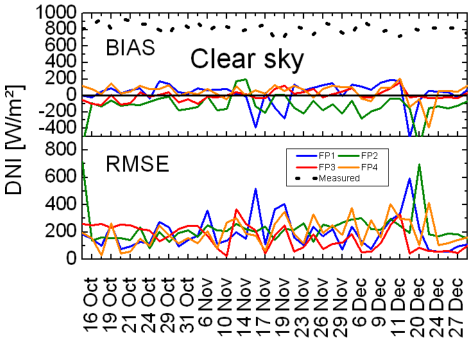

FIGURE 1. Daily BIAS (top figure) and RMSE (bottom figure) for 41 clear sky days. FP2 tends to underestimate the DNI (overall BIAS: -130 W/m²) while no clear trend is visible for the other FPs.

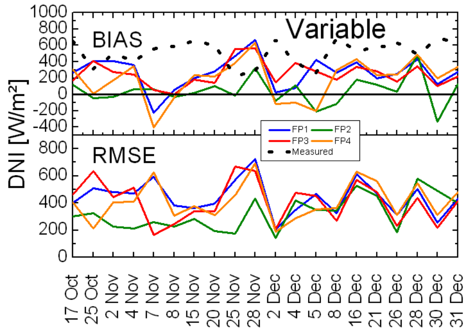

FIGURE 2. Daily BIAS (top figure) and RMSE (bottom figure) for 20 variable days. All FPs tend to overestimate the DNI. The RMSE is approximately twice as high as on the clear sky days.

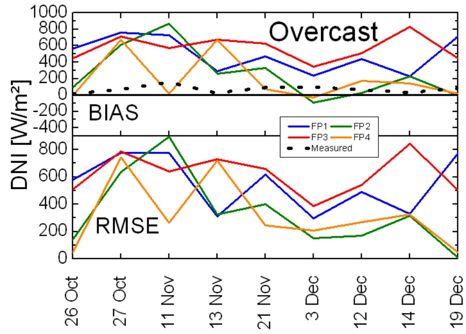

FIGURE 3. Daily BIAS (top figure) and RMSE (bottom figure) for 9 overcast days. A significant DNI overestimation by all FPs can be observed.

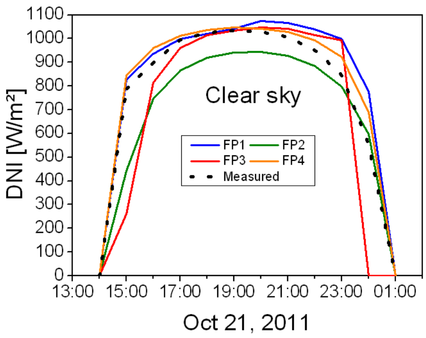

FIGURE 4. Measured DNI (dashed line) and forecast DNI (solid lines) on a clear sky day (Oct. 21, 2011): FP 4

is in best agreement with the measurement, whereas FP2 and FP3 show a time shift which may result from wrong coordinates or using other integration intervals than declared.

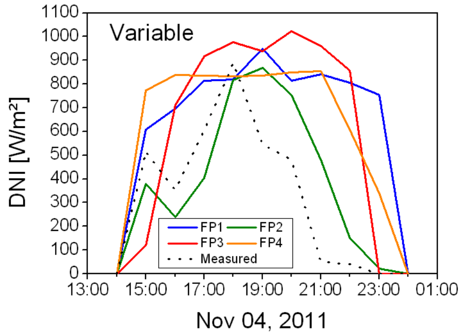

FIGURE 5. Measured DNI (dashed line) and forecast DNI (solid lines) on a variable day (Nov. 4, 2011): FP2 matches the DNI ramps in the morning quite well and consequently shows the lowest RMSE (cf. Fig. 2).

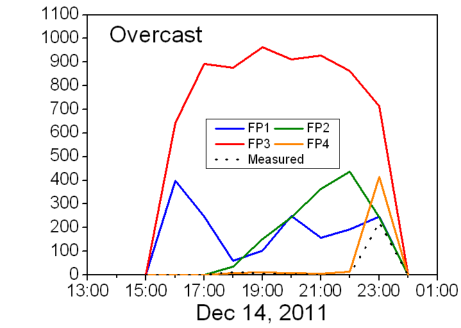

FIGURE 6. Measured DNI (dashed line) and forecast DNI (solid lines) on an overcast day (Dec 14, 2011): While FP3 predicts an almost clear sky day and FP1 as well as FP2 significantly overstimate the DNI, FP4 is in good agreement with the measured data.

Part 2:
Usage of cumulative distributions of DNI forecast error for evaluation

A forecast's operational value to a utility has to be measured within the context of the utility's use of the forecast. Here, we consider a utility using the day-ahead forecasts to support unit commitment scheduling and to estimate reserve requirements. In this context, a forecast is successful when the actual power delivery does not require substantial changes to the unit commitment schedule and reserve decisions. Discussions with utility planners and operators indicate that, in this context, a forecast fails when the actual power deviates from the forecast power by more than an acceptable error. The acceptable error can vary by season and time of day, and can differ in magnitude for positive error (forecast overestimates power) or negative error (forecast underestimates power).

The question arises: how to quantify the error? We explored this question with utility planners who expressed that errors should have units (of power), and that the likelihood of an error occurring is of key interest. We concluded that the cumulative distribution of error would be more informative than a statistic of error (e.g., RMSE or BIAS) or a normalized error (e.g., error expressed as a percentage of DNI).

Displaying the error distribution permits statements such as "the probability that the forecast exceeds actual by 150 W/m^2 is 0.3" which appealed to utility planners, because the latter can be interpreted as the likelihood (30%) that actual power will be less than forecast by a known amount (roughly 15% of capacity). By contrast, a statistical statement such as "mean bias error is 50 W/m^2" does not convey the likelihood that an error of this magnitude will occur, merely because over a long period of time, errors will average to this value. The statement "the probability that the forecast exceeds actual by 15%" does not distinguish between 15% of plant output when output is high and 15% of plant output when output is low, although the former may be of concern to a planner, while the latter may not.

Statistical measures of forecast error, or errors expressed as percentages, may be informative in context other than planning; for example, when choosing a forecast method, evaluating trends in a forecast over time, or when considering decisions over very long time scales such as those involving investments.

We computed cumulative distributions of DNI forecast error for daylight hours for day-ahead forecasts from four forecast providers (Figure 7) for a period of 86 days.

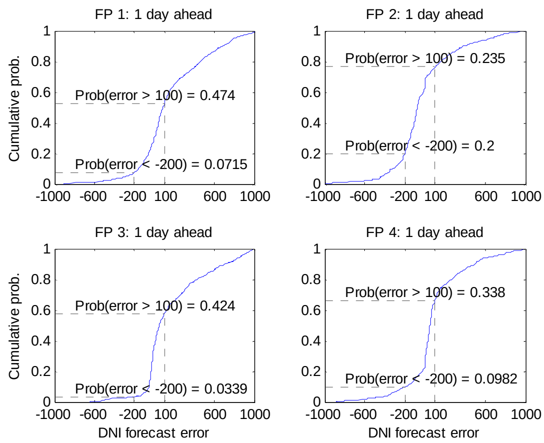

FIGURE 7. Cumulative distributions of DNI forecast error for four forecast providers (FP 1 through FP 4).

By way of illustration, we assumed that the utility planner accepts errors between -200 W/m^2 and +100 W/m^2. We found that, for three providers, the likelihood of an unacceptable underestimate is less than 10%, and the likelihood of an unacceptable overestimate of power to be as great as 47%. One provider (FP 2) was less likely to overestimate power (probability of 24%) but corresponding more likely to underestimate power (probability of 20%) than the other three providers. We also computed cumulative distributions for hourly forecasts at two and three days ahead; surprisingly, we observed similar distributions to those shown in Figure 1, which is counter to the prevailing notion that forecast performance declines as forecast horizon increases.

We also examined the dependence of forecast error on time of day. Figure 8 shows, for each hour, the count of forecast values that fell below the lower acceptable limit, fell above the upper acceptable limit, or fell between the limits. The total height of each bar indicates the the number of observations for that hour. Differences among the forecast providers are apparent in Figure 8.

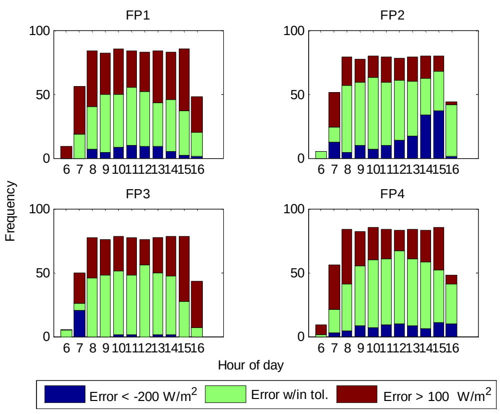

FIGURE 8. Forecast error by time of day.

HOUR AHEAD FORECAST EVALUATION

Only two of the four FPs provided hour ahead forecasts. Although the measured DNI was provided to the FPs with five minutes delay, i.e. almost in real-time, the evaluation of the HA forecasts suggests that it was not used to improve the quality by persistence algorithms. Due to the high errors in the hour ahead forecasts, as shown on two example days in Figure 9, this paper does not examine hour ahead forecasts in greater detail.

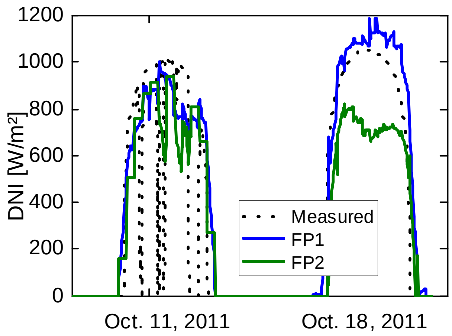

FIGURE 9. Measured DNI (dashed line) and DNI taken from the HA forecast (one hour ahead) from FP1 and FP2 (solid lines) on two example days in October 2011.

CONCLUSION

Day ahead DNI forecasts for one day ahead from four different forecast providers were evaluated for a site close to Questa, NM, USA over a period of three months. The forecast hourly DNI was compared to ground measurements. For 70 days of full data availability a mean DNI of 649 W/m² was measured. For this period, the RMSE for each forecast provider was found to be in the range of 300 W/m². A tendency to overestimation was found with three of the four providers, resulting in mean BIAS errors ranging from 104 W/m² to 154 W/m². For the fourth provider the BIAS was calculated to be -32 W/m.

Informal discussions with utilities indicated a preferrence to quantify the quality of a DNI forecast using probability rather than RMSE and BIAS. Therefore the cumulative distribution of DNI forecast error was calculated. For an example case of -200 W/m² as the highest acceptable underestimate and +100 W/m² as the highest acceptable overestimate, the corresponding probabilities vary between 3% and 20% for the underestimation and between 24% and 47% for the overestimation between the four providers.

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