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A Novel Approach for Probabilistic Photovoltaic Power Forecasting Covering Multiple Time Frames

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Abstract—Uncertainty in the upcoming production of photovoltaic (PV) plants is a challenge for grid operations and also a source of revenue loss for PV plant operators participating in electricity markets, since they have to pay penalties for the mismatch between contracted and actual productions. Improving PV predictability is an area of intense research. In real-world applications, forecasts are often needed for different time frames (horizon, update frequency, etc.) and are derived by dedicated models for each time frame (i.e. for day ahead and for intraday trading). This can result in both different forecasted values corresponding to the same horizon and discontinuities among time-frames. In this paper we address this problem by proposing a novel seamless probabilistic forecasting approach able to cover multiple time frames. It is based on the Analog Ensemble (AnEn) model, however it is adapted to consider the most appropriate input for each horizon from a pool of available input data. It is designed to be able to start at any time of day, for any forecast horizon, making it well-suited for applications like continuous trading. It is easy to maintain as it adapts to the latest data and does not need regular retraining. We enhance short-term predictability by considering data from satellite images and in situ measurements. The proposed model has low complexity compared to benchmark models and is trivially parallelizable. It achieves performance comparable to state-of-the-art models developed specifically for the short term (i.e. up to 6 hours) and the day ahead. The evaluation was carried out on a real-world case comprising three PV plants in France, over a period of one year.

Index Terms—Analog-Ensemble Model, Photovoltaics, Probabilistic Forecasting, Satellite Imagery

I. INTRODUCTION

IN recent years, continuous reduction of the cost of photovoltaic (PV) panels together with favorable policies have been the main drivers behind increased PV installation in electricity grids. However, weather-dependent PV production brings several challenges for grid operators. Accurate forecasts of the power output of PV plants are necessary to maintain economic and secure operation of the power system. Equally, PV producers and aggregators participating directly in electricity markets attempt to avoid financial penalties for any imbalances due to a mismatch between what they propose to the market and what they actually produce.

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In practice, decisions are often made over different cycles, i.e. trading on the day-ahead market requires models able to provide forecasts for the medium term (up to 48h ahead), while improving positions on the intraday market or managing coupled storage devices calls for short- or very short-term forecasting models (i.e. up to 6h ahead or minutes ahead respectively). For each time frame, dedicated models are employed that use as input the data sources that best contribute to performance during that particular frame. The operators or decision-support tools are presented with (probabilistic) forecasts from different models that are not always compatible, due to either discontinuities between time frames, or differences in the forecast values that correspond to the same horizon. In this paper we address this technical issue by proposing a forecasting approach independent of the time frame. This requires, however, that its performance must not be lower than that of the state-of-the-art models specifically developed for each time frame. The motivation goes beyond the above-mentioned technical issue, since the proposed approach simplifies the overall prediction model chain and thus makes easier the deployment of predictive analytics in a context of large-scale penetration of renewable energy sources. It is much easier for RES producers to employ just one model for all of their forecasting needs. Although the proposed approach is applicable for the case of other weather-dependent renewables, we focus here on PV prediction, since the state of the art comprises much more distinct approaches developed for short and medium time frames.

The state of the art in solar power forecasting has developed rapidly in recent years. Reference [1] provides a fairly complete literature review of research in the field.

The features used as inputs are largely dependent on the forecast horizon. Short-term forecasting (0-6 hours) mostly employs endogenous data, although input from Numerical Weather Predictions (NWP) and meteorological records can be used [2]. Works considering satellite imagery appear [3] and [4], while data from neighboring PV plants can be employed in spatio-temporal models [5]. Data from sky imagers are also useful for the very short term (up to a few minutes)[6], but harder to apply as they require significant preprocessing work. For the medium-term (up to few days ahead), forecasts mostly rely on NWPs. Regarding forecasting techniques, linear auto-regressive models are popular, as they are light and can issue forecasts at any time of the day using the same model [7]. Numerous machine learning models are also used, such as Artificial Neural Networks (ANN) [7] and Support Vector Machines (SVM) [8]. Recently, several new methods

have emerged. The Extreme Learning Machine (ELM) is a fairly popular variant of ANN [9], [10], [11]. Gaussian Process Regression (GPR) [12] and Markov Chain (MC) [13] models are also becoming more frequent in the literature. The global forecasting competition GEFCOM 2014 [14] showed that the most efficient algorithms were often non-parametric, such as Quantile Regression Forests (QRF) [15] and Gradient Boosting (GB) [16]. However, [17] performed a comparison of several non-parametric models and found that the performance difference between the tested models was low.

To achieve the objectives we defined above for a unique model over different time frames, we propose a model based on the Analog Ensemble (AnEn) family. These models look for historical situations with similar weather to the current conditions to generate a set of likely values (analogs) for the physical quantity to be forecast. A distribution can then be computed from this set of likely values. The base AnEn model that is extended in this paper was described in [18], where past NWP are used to forecast 10-m wind speed and 2-m temperature. In [19], the authors implemented a model in which they also looked for analogs using NWPs, but applying a different metric than that of [18].

In [20], the authors used the AnEn model to forecast probabilistic PV power for three large power plants. They emphasized the very low computational time needed to produce the forecasts compared to other models. Several papers have also proposed corrections or adaptations of the AnEn model to obtain better forecasts. Reference [21] proposed a modification of the Euclidian distance frequently used as a metric to evaluate analogs and used measures along with NWP to search for analogs. This reduced the forecast horizon, making it necessary to run the model multiple times to obtain a complete forecast. In [22] a 20 % improvement over the standard AnEn model with a brute-force optimization of the parameters was demonstrated. Several algorithmic variations of the AnEn ensemble, along with a dynamic way of selecting the number of analogs to retain in the ensemble, and a wrapper method to dynamically optimize the model parameters, were proposed in [23]. Reference [24] extended the AnEn model with an Artificial Neural Network (ANN) which significantly improved the forecasts. Finally, [4] proposed an Analog method to produce short-term forecasts of solar irradiance using geostationary satellite images only. Overall, the AnEn model still has some drawbacks. Since most of the time only NWPs are used, the forecasts are always the same until a new NWP run is available. Thus, it is not possible to use the model settings as found in the state of the art in an intra-day setting. Besides, although some papers have used data other than NWP in an AnEn setting, no model has used both NWP and other sources of data. Moreover, previous work do not present how they generate probabilistic forecasts from analogs.

The key contributions of this paper are 1) a methodology to extend the data that can be used in AnEn models, which includes a pre-processing step for using satellite images with a low computational cost; 2) a filter approach to compute the model parameters based on historical data without the need for a costly wrapper or offline optimization procedure. This results in a model that is "plant-free", because the model can

be used as is on any new PV plant and will directly compute its parameters without a learning process; 3) a formal way to produce probabilistic forecasts from the Analog Ensemble using a Kernel Density Estimation (KDE); 4) a model that is dependent on the forecast horizon and the starting time of the forecast, so that the number of parameters are not multiplied when starting the model at different times. This translates to a unique seamless model for short and medium time frames that allows us to simplify the overall model chain in practical applications without compromising accuracy. 5) a model that is able to have state-of-the art performance in the 5-minute to 36-hours horizon range, that can be used in all energy applications such as control of a PV/Storage system combined plants, or day-ahead bidding in an electricity market.

The paper is structured as follows: in Section II, the modifications made to the AnEn model are presented. Then Section III presents the case study on which we tested the extended model, comparing it to a state-of-the-art forecasting model and Section IV presents the results of the study. Finally, Section V draws the conclusions of the paper.

II. ANALOG ENSEMBLE MODEL

A. The AnEn Metric

The aim of the AnEn model is to generate a set of past observations considered similar to the situation we want to forecast, and use this set to build the forecast density. Initially we generate an N -member ensemble for a given lead-time by computing a metric between the situation to forecast and all of the past situations. Then we select the N most similar to past situations and look for the PV power measured at the time of these similar situations. These N measures constitute the analog ensemble, and each analog can be thought of as a sample from the probability density function (PDF) of the PV power. In the most general formulation of the metric taken from [18], only NWPs were used as inputs. The metric used in this paper is based on the one defined in [18] but it is adapted to allow different sources of data to be taken into account. It can be written as follows, for a forecast with lead-time t and horizon h (that is, started at time $t - h$):

$$D(\mathbf{X}_t, \mathbf{H}_{t'}^h) = \sum_{i=1}^{N_v} w_i^h \sqrt{\sum_{j=-k}^0 (\mathbf{X}_{i,t+j} - \mathbf{H}_{i,t'+j})^2} \quad (1)$$

where N_v is the number of features used as input, and k is a parameter that indicates the length of the time window over which the metric is computed. \mathbf{H}^h and \mathbf{X} are two sets containing the features and input of the model. The set \mathbf{H}^h contains variables from NWP, along with the measures lagged h times. This set is dependent on the horizon of the forecast. When we make a forecast with horizon h , the last measures were observed h time steps ago, and this should be reflected in the historical data set. Following through, \mathbf{X} contains the NWP for time t and the latest measures, observed at time $t - h$. \mathbf{H}^h and \mathbf{X} are scaled and centered, so that each variable contributes to the metric with the same proportion. Thus, only the weights w_i^h can control the importance of each feature.

The weight calculation takes into account the forecast horizon and is presented in the next sub-section.

To our knowledge, previous papers have not presented how they generated the PDF from the analogs. In this paper, it is built by a weighted Kernel Density Estimation (KDE), using the metric value of each member as their weight in the distribution. Given a set of N_{An} AnEn members P_i , and their distance value D_{An} , the PDF \hat{f} is estimated by:

$$\hat{f}(P) = \frac{1}{\sum_{i=1}^{N_{An}} s_i} \sum_{i=1}^{N_{An}} \frac{s_i}{bw} \left[K\left(\frac{P - P_i}{bw}\right) + K\left(\frac{P + P_i}{bw}\right) + K\left(\frac{P + P_i - 2P_n}{bw}\right) \right] \quad (2)$$

where P_n is the installed power of the given plant, the s_i terms are similarity measures inversely proportional to the distances, K is the Epanechnikov kernel, and bw is the bandwidth of the kernels. The first Epanechnikov evaluation corresponds to the kernel centered around the i -th AnEn member value, and the two others are there to ensure that the integral of the distribution is 1 between 0 and P_n . Outside this range, the PDF is set to 0.

The different sources of data that the paper aims to integrate are: variables from NWP, in situ measurements, clear-sky profile, and spatial data derived from satellite imagery. The clear-sky profile is an estimation of the solar irradiance on the ground under the assumption that there are no clouds. Following these notations, the integration of a clear-sky profile and local measurements is pretty straightforward. However, satellite data is more complex because they have many more features, which require reducing. The required additional processing work will be detailed in Section II-B.

B. Dynamic Weights Computation

The calculation of the feature-weights is critical. In previous works [22], [25], [23], these were obtained from an off-line optimization for each power plant and remained the same throughout the testing period. In these cases, a measure of the probabilistic performance of the models was used as the optimization objective. In this paper, we do not use the final performance as a criterion, but we propose a dynamic way to estimate weights based on the most recent data, since the model operates in a sliding window scheme and the weight of the latest measurements will not be the same for a forecast started at noon as for one started at midnight. The criterion used to quantify the weights is Mutual Information (MI), which is often used in machine learning for feature selection [26]. This is a measure of how much the fact of knowing a variable reduces the uncertainty of another variable. The MI between two random variables X and Y , knowing their respective marginal density distributions p_X and p_Y and their joint density distribution $p_{X,Y}$, is:

$$MI(X, Y) = \int \int p_{X,Y}(x, y) \log\left(\frac{p_{X,Y}(x, y)}{p_X(x)p_Y(y)}\right) dx dy \quad (3)$$

The main reason we chose this criterion rather than simpler ones, e.g. Pearson's correlation, is because it can identify non-linear relationships between random variables. As we are dealing with both features that are strongly and almost linearly correlated to the production (clear-sky profile, last production measure), and features that are not (temperature from NWP), using a linear correlation criterion would overestimate the weight of the former over the latter. On the other hand, the MI calculation identifies the non linear information contained in the variables and thus avoids giving significant weights only to variables that are linearly correlated with the PV production.

The weight calculation is carried out in two steps. The first step is to evaluate the relevance of each variable individually by calculating its MI with the measured power according to (3), using empirical estimates of the distributions. The second step is to set a limit on the total cumulative weight of each source of data. If such a limit were not set, the contributions of two redundant features would accumulate even though they carry almost the same information. Setting a total weight limit attenuates the impact of redundant features in a given source by limiting the total contribution of the source.

In a more formal way, the weights are computed as follows. In the first step, intermediate weights $w'_i{}^h$ are obtained by equation (4), where L^h is the lag operator and E_{PV} are the power measurements. Then, the weights are normalized. In practice, the input variables are organized into N_s subsets $S_v, v \in [1, N_s]$ depending on their source (NWP, measures, satellite data, clear-sky profile). A global weight $W_{S_v, h}$ is attributed to each source of data and horizon. For a given variable i , we note S_v, i as the set in which the variable i is included. We then obtain the final weights with equation (5).

$$w'_i{}^h = MI(L^h(H_i), E_{PV}) \quad (4)$$

$$w_i{}^h = \frac{w'_i{}^h}{\sum_{k \in S_v, i} w'_k{}^h} W_{S_v, i, h} \quad (5)$$

The computation of $W_{S_v, h}$ should be done taking into account redundancy between variables from the same source. This is especially important for satellite data where the variables are strongly correlated. We propose to use:

$$W_{S_v, h} = \max_{i \in S_v} w'_i{}^h \quad (6)$$

This means that each source of data contributes to the metric as much as the weight of its most informative feature does. As a result, we may underestimate the information conveyed by variables that are not strongly correlated to the PV production, but we will not overestimate the global contribution of a source of data that contains numerous intercorrelated variables, since the individual weights of the redundant features will not add up to more than the weight $W_{S_v, h}$ of their source.

Fig. 1 shows the average weights obtained for each type of data and for different time horizons. All of the forecasts started at 12 p.m., while no weights are computed for horizons corresponding to nighttime. The details of the case study are described in Section III. The values of the weights of the different sources correspond well with results reported in the literature concerning which source of data is informative for

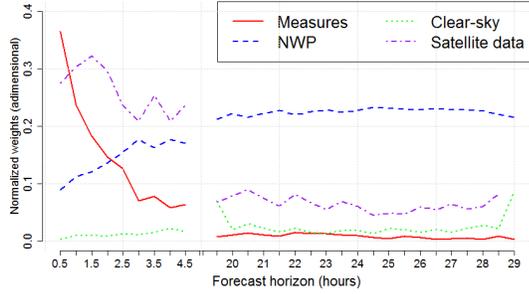


Fig. 1. Weights of the different sources of data depending on the forecast horizon

which horizon. The most recent power measurement is very informative for the first few time steps, but its weight decreases quickly. NWP's are always relevant, but even more so for day-ahead purposes. For horizons shorter than 4 h, they carry less information than the latest measurements and the satellite data. Satellite data are very useful up to 6 h, even though their value decreases steadily. Equally of interest, the clear-sky profile is useful almost only for the beginning and end of the day, when it becomes the most important feature. It is not surprising to see that for these instants with very low incoming irradiance even in clear-sky conditions, the amount of solar power is not dominated by the presence of clouds, but by the Sun's path.

C. Integration of Satellite Data

In the proposed model, estimated GHI (Global Horizontal Irradiance) time series are derived from the satellite images for each pixel (see III-A). We propose to use these time series as conditioning features for the AnEn model when it looks for analogs. Since the model looks for analogs by matching features on several time steps as described by the parameter k from equation 1, and the pixels used to condition the forecasts are in the neighborhood of the plant, we use both the spatial and temporal information from the images. Still, this method is simpler than standard ones, i.e. Cloud Motion Vector [27], as it does not try to anticipate the future state of the cloud layer. The choice of taking a purely data-driven approach rather than including a preprocessing step for the images to derive cloud motion information is one of the design requirements set here in order to maintain simplicity in the proposed model chain. The mechanism of the AnEn model, where a series of past images is linked to future situations through the analogs, is a process that is expected to reflect the mechanism according to which the temporal variations in the images that reflect cloud motion impact PV production. Section IV demonstrates that the inclusion of satellite images as conditioning features is beneficial to the model. This section describes the selection process for the pixels we use to compute the model.

Two parameters must be estimated before including the satellite-estimated GHI. The first one is the maximal distance D_{max} between the power plant and the points for which we use the GHI estimation in the model. Theoretically, the greater this distance, the longer the time horizons for which the estimated GHI time series can be useful. However, increasing

D_{max} quadratically increases the number of pixels to be considered. To avoid computational issues, we have to set a limit on this distance D_{max} . The second parameter is the number N_{pix} of pixels we select to derive the features, within the area defined by D_{max} . The selection of a specific pixel from the satellite image results in a GHI time-series from consecutive images. We propose to keep the most informative N_{pix} time-series according to their MI with PV production.

To define D_{max} , we first obtained features estimated from pixels within a 150 km radius as an upper-bound. Then, for different time horizons h , we computed the MI between the GHI time series derived from each pixel lagged h time and the PV production over one year. We could then visualize the location of the most informative time series for each horizon, as shown in Fig. 2. From visualizing the data, we found that for time horizons below 90 min, the global level of the information of the estimated GHI time series is significant compared to other horizons. There is also a significant difference between the most and the least informative time series, the most informative ones being located within a 50 km radius from the plant. On the contrary, for greater horizons, the information is scant. Thus, it does not seem necessary to have a large D_{max} for longer time horizons, or to use satellite data at all. In the end we kept a 50 km value for D_{max} .

We defined the number of features selected within a D_{max} radius by fitting LASSO (Least Absolute Shrinkage and Selection Operator) models with a 10-fold cross validation, using all the estimated GHI time series as features to predict the production for horizons ranging from +30 minutes to +36 h with a half-hourly time step, that is, for 72 different horizons. For a given horizon h , we obtained the LASSO models with:

$$\hat{E}_{PV,t+h} = \hat{\beta}_0^h + \sum_i \hat{\beta}_i^h X_{t,i} \quad (7)$$

$$\hat{\beta}^h = \underset{\beta}{\operatorname{argmin}} \left((E_{PV} - \hat{E}_{PV})^2 + \sum |\beta_i^h| \right) \quad (8)$$

where $X_{t,i}$ is the estimated GHI for the i -th pixel for time t , and β^h are the parameters of the model.

LASSO models have a built-in tendency to produce a sparse feature selection, and to randomly drop features when they are strongly correlated. As our estimated GHI time series are indeed correlated, we took the feature selection performed by the LASSO models as a measure of the redundancy in the time series, instead of actually selecting the most relevant features. We then obtained N_{pix} by averaging the number of features kept by the LASSO models over all horizons:

$$N_{pix} = \frac{1}{72} \sum_{i=1}^{72} \frac{\#j : \hat{\beta}_j^i = 0}{\#\hat{\beta}^i} \quad (9)$$

In the end, we obtain $N_{pix} = 37$ features, which represent around 12% of the total number of pixels considered. This value is retained for the forecasts in Section III. Fig. 3 shows the average selection probability for each feature within the area defined by D_{max} , for all forecasts started at 12 p.m. For the 30-minute horizon, the selected pixels are concentrated in an area east of the plant. This suggests that the weather

conditions propagate from east to west, which could be explained by the Sun's path, but also by local weather conditions (e.g. a systematic east wind). For the 90-minute forecast, a slight concentration persists to the east of the plant. After this horizon, no recognizable pattern can be found.

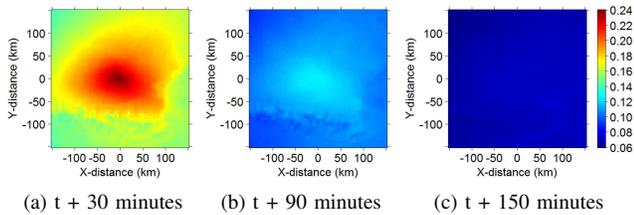


Fig. 2. Mutual information between each estimated GHI time series and the lagged production for different time lags

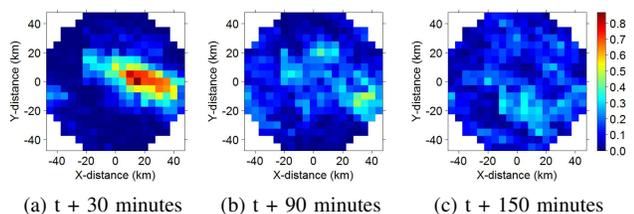


Fig. 3. Probability for each pixel to be selected for different forecast horizons

III. CASE STUDY

A. Data

The proposed AnEn model was used to forecast the power output of three PV plants located in southwest France. The plants are denoted as P1, P2 and P3 respectively and have a nominal power of 9504, 2694 and 6876 kWp. The available measurements cover the period from January 2014 to December 2016. NWP are obtained from the European Center for Medium-range Weather Forecasts (ECMWF). The forecasts are made on a $0.1^\circ \times 0.1^\circ$ latitude/longitude grid every 12 hours. The NWP variables used as features are the Surface Solar Radiation Downwards (SSRD), 10-m U- and V-wind speed (10U and 10V), 2-m temperature (2T), Total Cloud Cover (TCC) and Total Precipitations (TP). In situ measurements come from the power plants' monitoring systems. The measurements taken into account are PV power, temperature, and GTI. The clear-sky profile is computed using the model McClear [28]. Lastly, features obtained from the MSG satellite imagery are computed using the HelioClim-3 database with the HelioSat-2 method [29], [30]. The images are converted into a time series of estimated GHI for each pixel. At the location of the plants, each pixel corresponds to a $5 \text{ km} \times 5 \text{ km}$ surface.

B. Simulation

Taking the French energy market EPEX SPOT as reference for the case study, the forecast horizons required for trading on both the day-ahead and the intra-day markets are from +30 minutes to +36 hours. Since the measurements were

available from January 2014 to September 2018, all of the data necessary to perform the simulation were obtained for the same period. All of the data were then converted to 30-minute time series to obtain the same time step as the market time unit. The clear-sky profile and in situ measurements have a native 5-minute resolution and the satellite images have a 15-minute resolution. These variables were summed over 30-minute intervals to obtain the 30-minute time series. The NWP have a native 1-hour resolution. All NWP fields were linearly interpolated to obtain the 30-minute time series. However, numerous applications, such as real-time control of a combined PV and storage power plant, also require short-term forecasts with horizons lower than 30 minutes. Using the exact same model but feeding it with the native 5-minute data, and with 5-minute interpolated NWP and satellite data, we could provide forecasts with a 5-minute resolution.

To assess the quality of our model, we consider a QRF as a benchmark model for the 30-minute resolution forecasts, because it is widely used and featured several times in the leaderboard of the GEFCOM 2014 [14]. This model is an extension of random forests that can provide quantile forecasts [31]. Here, it is trained using the same variables as the AnEn except for the satellite data that caused computational time of the QRF to be too long, along with their one-time-step lagged values. Note that what we call the QRF model is actually a collection of 72 models, each one trained for forecasting a specific horizon, because they have to treat the relative importance of the last measure differently regarding the horizon. This process is automated in the AnEn model, so that there is a single model for all the horizons. This is in argument supporting the fact that the AnEn model "unifies" time frames, as a single model gives consistent forecasts from +5-minutes to +36-hour horizons. For the 5-minute resolution forecasts, we used an Auto-Regressive Integrated Moving Average (ARIMA) model, which is best suited for short-term forecasts, using only the production data as input. Another reason why we used the ARIMA instead of the QRF for these horizons is the very demanding computational time of the QRF at this resolution, as can be seen from Table I.

The period from May 2016 to April 2017 was used to estimate the structural parameters of the AnEn model and the QRF model used as benchmark through trial and error. The ARIMA order was also obtained by minimizing the Akaike Information Criterion (AIC) on the testing set. Then, to assess the performance of the models, PV power was forecast from May 2017 to April 2018 with the AnEn and QRF models, from 30 minutes to 36 hours ahead with a 30-minute resolution. The forecasts were updated every 30 minutes following a sliding window scheme. For each new forecast, the set \mathbf{X} was updated using the latest in situ measurements, NWP, and satellite-derived GHI estimations. In addition, the set \mathbf{H} was updated with the most recent data available at the time to identify the analogs. We also performed the same evaluation for the ARIMA and AnEn models with the 5-minute resolution forecasts, forecasting from +5-minute to +60-minute horizons, and updating the forecasts every 5 minutes.

TABLE I
COMPUTATION TIME REQUIRED FOR PROVIDING THE FORECASTS FOR
ONE GIVEN HORIZON, DEPENDING ON THE FORECAST RESOLUTION

Forecast resolution	Required computational time (seconds)		
	AnEn	QRF	ARIMA
30 minutes	2	10	≤ 1
5 minutes	6	120	≤ 1

IV. EVALUATION RESULTS

Probabilistic forecasts are more complex to evaluate than deterministic ones. Numerous properties are required for predictive densities, while identifying some aspects of the forecasts may fail when using only proper scoring rules. The main required properties are reliability and sharpness. The results are presented for plant P3 in the following parts, as the behavior of the models was similar for the different plants. Deterministic criteria are also presented for comparison purposes with results from standard deterministic models in the state of the art. The averaged results are summarized in Table II. All the evaluation criteria from Table II are described in detail in the following parts. All results are given in %, relative to the installed power of the plant.

A. Reliability

The standard way to evaluate a forecasting system is first to assess the reliability of the model. The forecasts are reliable if the level of each quantile matches the frequency of the observations. For a perfectly reliable model, the empirical quantile level should be the same as the nominal one, and thus the reliability diagram should be a diagonal line. Fig. 4 shows the reliability diagram of the two models. Consistency bars are also added following [32] to indicate a range within which even a perfectly reliable model could be situated due to the finite size of the testing set. Both models seem reliable, since they both fall within the acceptable range. In Table II, Reliability (R) reports the mean absolute reliability deviations from the diagonal over several forecast horizons.

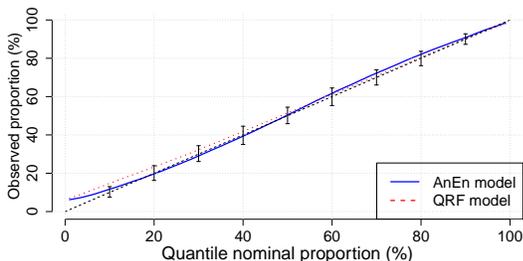


Fig. 4. Reliability diagram of the two models including consistency bars

B. Sharpness

Sharpness measures the spread of the forecast distribution. As an example, a Dirac distribution would have a perfect sharpness, while a uniform distribution would have a very low

sharpness. The goal of any probabilistic forecasting system is to be as sharp as possible, while maintaining its reliability. In this paper, sharpness is assessed using the Prediction Interval Normalized Averaged Width (PINAW) metric. Noting $I_{i,\alpha}$ the width of the PI with coverage rate α , it writes as follows:

$$PINAW(\alpha, h) = \frac{\sum_{i=1}^N I_{i,\alpha}}{P_n} \quad (10)$$

Fig. 5 shows the PINAW for different forecast horizons and nominal coverage rates α . The PINAW are very similar for the two models. In Table II, Sharpness (S) reports the mean PINAW over several horizons and all nominal coverage values.

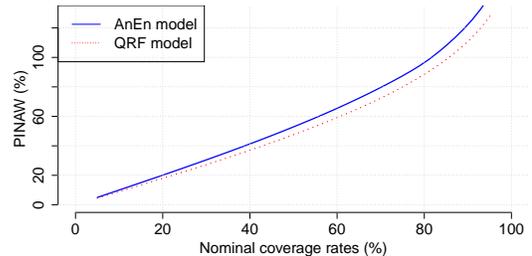


Fig. 5. PINAW for different forecast horizons

C. CRPS score

At this point, it is difficult to tell which model performs better, since they show very similar results for both reliability and sharpness. The overall performance of the models is evaluated using the CRPS, which is a score system dedicated to probabilistic forecasts. It takes into account both reliability and sharpness. The CRPS is defined for a given distribution f and its correspondent cumulative distribution function F , along with an observation y , by:

$$CRPS(F, y) = \int_{-\infty}^{+\infty} (F(u) - \mathbb{1}(y \leq u))^2 du \quad (11)$$

Fig. 6 presents the CRPS of the two models depending on the horizon, normalized by the nominal power of the plant. The difference between the models is clearer when the score is plotted conditionally to the forecast horizon. The QRF model outperforms for forecast horizons longer than 3 hours. For shorter horizons, the AnEn model performs much better. However, as can be seen from Table II, the overall CRPS differences between the models are very low, and they both show state-of-the-art performance.

D. RMSE

The Root Mean Square Error (RMSE) is also computed, taking the densities medians as a deterministic forecasts. This allows us to compare the model with standard deterministic ones. We compared the AnEn and QRF with two variants of the classic persistence models. The first variant, noted Persistence 1, gives the power measurement of the day before

TABLE II
EVALUATION RESULTS

Plant	30-minute resolution forecasts								5-minute resolution forecasts			
	AnEn				QRF				Persistence 1	Persistence 2	AnEn	ARIMA
	R	S	CRPS	RMSE	R	S	CRPS	RMSE	RMSE	RMSE	RMSE	RMSE
Forecast horizon 0-2 h												
P1	1.43	12.4	4.24	9.54	0.90	13.4	4.44	9.94	20.9	16.5	-	-
P2	1.97	12.8	4.25	9.93	2.03	14.1	4.44	10.1	23.4	16.6	-	-
P3	1.90	12.3	4.14	9.52	1.74	13.3	4.38	9.98	20.7	15.9	10.1	10.2
Forecast horizon 2-36 h												
P1	2.55	14.4	5.26	11.6	2.17	14.3	5.08	11.4	20.9	36.5	-	-
P2	1.84	16.0	5.52	12.5	2.10	15.1	5.36	12.3	23.4	37.6	-	-
P3	1.00	14.8	5.30	11.9	1.80	14.2	5.21	11.8	20.7	35.6	12.8	16.8

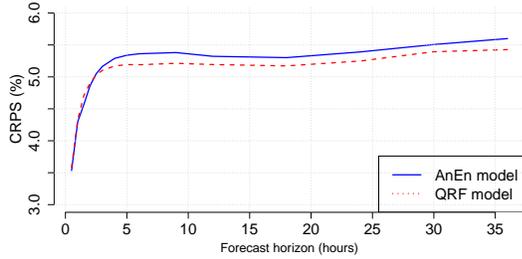


Fig. 6. CRPS performance of the AnEn and the QRF models

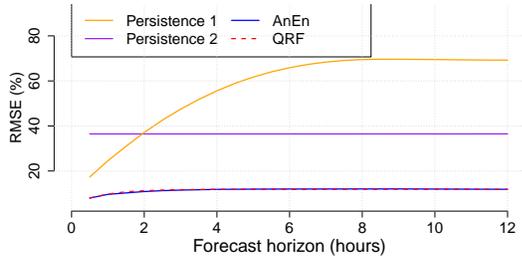


Fig. 7. RMSE of the models depending on the horizon

at the same time of the day as the forecast. The second, noted Persistence 2, gives the power observed at the starting time of the model as the prediction for all horizons. The RMSE for a set of K forecasts \hat{y} and their associated observations y is:

$$RMSE(\hat{y}, y) = \sqrt{\frac{1}{K} \sum_{i=1}^K (y_i - \hat{y}_i)^2} \quad (12)$$

The RMSE of the models depending on the forecast horizon is presented on Fig. 7. Both AnEn and QRF models consistently outperform Persistence 1 and 2 for all horizons.

E. Intra-hourly forecasts

Figure 8 shows the average RMSE conditioned to the forecast horizon for the AnEn, ARIMA and Persistence 2 models for the 5-minute resolution forecasts. The AnEn model is consistently more accurate than the two other models for intra-hourly forecasting. Besides, even though it is not shown

with the RMSE criterion, the AnEn provides uncertainty information since it gives a probabilistic estimate of the production.

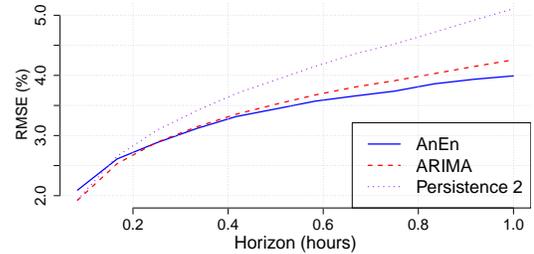


Fig. 8. Comparison of AnEn, ARIMA and Persistence 2 models for intra-hourly forecasts

F. Contribution of Each Source of Data

Fig. 9 shows how CRPS performance increases when adding incrementally different sources of data. The addition of the last measure significantly increases performance for time steps up to 5 h. This is self-explanatory, as the last measure is very informative about the current meteorological situation, but carries little predictive information. The addition of satellite data slightly increases performance up to the 3-hour forecast horizon. This confirms that the added value from satellite data extends up to a few hours, as expected from the literature.

This result is quite interesting, as it shows that the model is able to process both temporal and spatial information from very different sources of data. It could be extended by other features, that are known to improve solar power forecasting, such as measurements from neighboring PV plants or weather stations. However, this would require further work when assigning global weights to each source of data. In our case, using the maximal feature weight as the global weight of the whole source was efficient as the information between each source of data was not redundant. When increasing the sources of data, the chances are higher that two sources of data will carry correlated information. This should be considered for the global weight assignment.

V. CONCLUSIONS

In this paper, a probabilistic PV power forecasting model is proposed that is well suited for use by a power plant

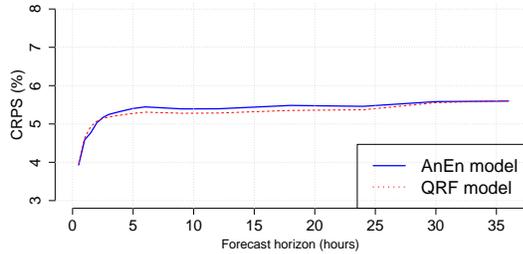


Fig. 9. Comparison of the performance of the AnEn model depending on the inputs

operator trading in day-ahead and intra-day electricity markets. The model was found to (1) have state-of-the-art performance in the +5-minute to +36-hour forecast range; (2) be able to dynamically adjust to the most recent data, so that any change in the PV plant (surrounding environment, partial outage, soiling, etc.) can be automatically dealt with; (3) be able to start at any time of the day for any forecast horizon without multiplying the number of models.

The good performance of the model for both intra-day and day-ahead forecasts was achieved by including in situ measurements and data from satellite imagery along with NWP. Specifically, efforts were made to deal with the high dimensionality of satellite data. Further work could include other sources of data in the model. The proposed model was proven to be an efficient alternative, both in terms of computational cost and accuracy, to the state-of-the-art approach where different forecasting models are employed as a function of the available data types and the application time frame.

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