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The value of day-ahead forecasting for photovoltaics in the Spanish electricity market

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ABSTRACT

Traditionally, the accuracy of solar power forecasts has been measured in terms of classic metrics, such as root mean square error (RMSE) or mean absolute error (MAE), and it is widely accepted that the smaller the error, the greater the economic benefits. Nevertheless, this is not as straightforward as it may seem, because market conditions must be studied first. Relationships between magnitudes of deviations between forecast and actual production and market penalties that apply at each moment are crucial.

In this study, we analyze various day-ahead production forecasts for a 1.86 MW photovoltaic plant considering different techniques and sets of inputs. A nRMSE of 22.54% was obtained for a Support Vector Regression model trained by numerical weather predictions (NWP). This model produced the most benefits. An annual forecasting value of 4788€ with respect to a persistence model was obtained for trading in the Iberian (Spain and Portugal) day-ahead electricity market. Annual value added by the NWP service totaled 2801€ and room for improvement regarding NWP variables rose to 3877€. As a general trend, it was found that smaller errors (RMSE) generated higher incomes. For each 1 kW h improvement in RMSE, the annual value of forecasting increased 22.32€. Nevertheless, some models that gave larger errors than others also brought greater benefits. Thus, market conditions must be considered to accurately evaluate model economic performance.

1. Introduction

The Paris Agreement (UNFCCC, 2017), which is to be ratified by 197 countries, establishes foundations for countries' future energy development. Its goal to keep global temperature increase below 2 °C in this century (with respect to pre-industrial levels) promotes the reduction of fossil fuel use and a shift to renewable energies. Thus, electricity systems must be adapted to characteristics of those variable energy sources, such as solar or wind, in order to allow a greater penetration without risking the balance of the grid. Photovoltaic (PV) technology is already a key component in the energy mix of many countries, such as Italy or Germany, where its contribution reaches 8% and 7% of total energy produced, respectively (IEA, 2015).

Forecasting the amount of energy produced by a PV plant is indispensable to allow an optimal integration. Models for the prediction of production use solar radiation forecasts as one of the most important inputs. However, errors arise because transient cloud patterns and aerosol spatio temporal variability cause considerable variability of solar radiation over a wide range of scales. These phenomena are often difficult to forecast. With regard to the forecast horizon, current reference methods for solar radiation forecasting are statistical models using pointwise ground measurements or spatially-distributed observations of the cloud field from sky cameras and satellite imagery, or simulations of atmospheric evolution using Numerical Weather Prediction (NWP) models (Diagne et al., 2013; Inman et al., 2013; Lorenz and Heinemann, 2012). The choice of model depends on the target forecast horizon: from intra-hour (IH) to day-ahead (DA) or longer. The difficulty of predicting future sky conditions has motivated research on forecasting and thus there are many studies worldwide focused on solar power forecasting.

Prediction models can also be based on physical equations (Dolara et al., 2015), which convert irradiance into power output following a PV plant model, or rely on statistical models (Zamo et al., 2014) that are data driven and do not need any information from the solar plant. Hybrid models (Vaz et al., 2016), which combine two or more techniques, have become a common means to foster individual strengths. A thorough review of the state-of-the-art of solar power forecasting is in Antonanzas et al. (2016).

Deviations between forecast and actual energy affect both transmission system operators (TSOs) and market agents (MAs) who work

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with solar energy. The former have to readjust the operation of some power plants in the energy mix to offset such unexpected changes, while the latter face penalties derived from the readjustment. The precise way in which these situations are resolved is country and system-specific.

There are a limited number of studies that address the economic implications of solar power forecast accuracy, which can be approached from two perspectives, grid operation and market bidding. With the former, Brancucci Martinez-Anido et al. (2016) studied the Independent System Operator-New England (ISO-NE), considering the behavior of the bulk power system and value of DA forecasting. They observed the consequences of improving solar power forecasts in different scenarios of solar penetration. Solar curtailment declined as the accuracy of the forecasts increased. For the actual penetration scenario (4.5%) in the ISO-NE, a uniform improvement with respect to state-of-the-art forecasting from 0% to 50% suggested important economic benefits, but better forecasts (50–100% improvement) did not accrue much additional benefit. Kaur et al. (2016) analyzed the role of improved forecasts in energy imbalance markets, highlighting important reductions in flexibility reserves and the probability of imbalance. Zhang et al. (2015) established target values for metrics that would reduce spinning reserves in the California Independent System Operator, bringing substantial savings.

With the market bidding point of view, a question arises: Do more accurate forecast models (in terms of root mean square error (RMSE), mean absolute error (MAE), and others) bring more economic benefits to MA? The answer looks clear, but is not as straightforward as it seems, because the correlation of errors with imbalance penalties must be studied first. Kraas et al. (2013) analyzed the influence of the use of enhanced direct normal irradiance (DNI) forecasts for a concentrated solar thermal plant on deviation penalties from forecast errors in Spain. They concluded that the economic value of any increase in DNI forecast accuracy follows an almost linear function, with slope 0.7/% gain. Cormode et al. (2014) investigated solar power curtailment to avoid penalties from ramp rate rules in the state of Arizona, which were defined as a variation of 10%/min of plant capacity. Penalties applied at \$0.1/s MW. Several scenarios were tested, varying the procedure to determine the curtailment. If no curtailment was applied, the plant would see its gross revenue reduced to 80% of the maximum revenue because of penalties. De Georgi et al. (2015) analyzed the Italian market and stated that penalties applied when deviations between scheduled and actual production surpassed a tolerance range of $\pm 10\%$. They observed that the probability of being within the tolerance range was close to 40% for the least squares support vector machine (SVM) model, and the benefit obtained was 76% of the maximum. Ruhnau et al. (2015) addressed the issue considering that the economic value of forecasts was related to the correlation of errors between the expected production and market prices. They concluded that best forecasts should have high accuracy but maintain weak correlation with other MA forecasts. Law et al. (2016) analyzed the economic value of DNI forecasts for a concentrated solar thermal plant in Australia. They proved that each 1 W/m^2 improvement in RMSE (valid range 300–400 W/m^2) translated into an annual increase in financial value of \$400–\$1300.

The goal of the present study was to determine the value of PV power DA forecasting in the Iberian (Spain and Portugal) electricity market under actual conditions (years 2009–2010). Several models using various sets of inputs were tested to determine if classical error metrics were correlated with economical benefits from the MA point of view. The value of forecasting (VoF) with respect to a two-day persistence model was also assessed. The remainder of the text is as follows. Section 2 describes the Spanish electricity market and Section 3 details the statistical models used for power predictions and the economic model to account for penalties. Section 4 describes the data used. Section 5 analyzes market conditions during the evaluation period and results from a statistical and economic perspective and addresses the assumptions made in the study and their potential implications for the results. Finally, Section 6 summarizes the major findings.

Table 1
Spanish intraday market schedule.

Session number	1	2	3	4	5	6
Session opening	17:00	21:00	01:00	04:00	08:00	12:00
Session closing	18.45	21.45	01.45	04.45	08:45	12.45
Schedule horizon (h)	27	24	20	17	13	9
Hourly periods	22–24	1–24	5–24	8–24	12–24	16–24

2. Iberian electricity market

The Iberian electricity market comprises the entire Iberian Peninsula (Spain and Portugal). It consists of two kinds of markets, the Day-ahead Market (DAM) and Intraday Market (IM), which are regulated by the market operator (MO). The MO for the Iberian Peninsula is OMIE (*Operador del Mercado Ibérico de Electricidad*). The DAM takes place on day D, and the energy for day $D + 1$ is fixed. Each MA must present their sale and purchase offers before the gate closure time, 12:00 local. The intersection of the offer and demand curves dictates the marginal price (MP), also called the pool price. Then, the TSO (Red Elétrica de España) solves technical restrictions and presents the provisional daily viable schedule. When ancillary services are included in the schedule, that schedule is obtained, before 16:00 local. Then, six IMs are convened to allow updating of forecasts and avoid imbalance penalties. Table 1 shows the IM schedule.

The TSO has his own power forecasting tool for solar energy production, called SIPRESOLAR, to control the grid. This is because they cannot depend on forecasts from MA, which normally include market strategies. Because this works with aggregate production for an entire country, errors are normally small because of the "smoothing effect". It is based on artificial neural networks.

After each IM session, if expected deviations are greater than 300 MW h for the full system at any hour until application of the next IM session, the TSO convenes the deviation management market. Then, the final hourly schedule is presented for the time horizon between the finalization of that IM and application of the subsequent IM.

Deviations from the scheduled production that require a solution by the TSO involve additional costs, which are distributed between those MAs who caused the distortion. There are two situations: the system needs more energy (either because of underprediction of the demand or/and overprediction of generation) or less energy (either because of overprediction of the demand or/and underprediction of generation). These situations will be hereafter called "short" and "long", respectively. The Iberian electricity market (OMIE) considers dual imbalance pricing to solve penalties. These two values are as follows:

- Buy price for rising deviations (BP): This is the price at which the system buys excess energy produced by a MA (with respect to scheduling) when the system is long. Because the BP is equal to or less than the MP, the MA will receive less income for energy produced over schedule, which could have been sold at the MP.
- Sell price for falling deviations (SP): This is the price at which the MA buys energy not produced (with respect to scheduled) when the system is short. The MA will be penalized for energy produced under schedule, which was sold at the MP but since it was not finally produced, will have to be bought at a higher price (SP) to meet the schedule.

We assumed that all energy was traded in the DAM because of the complexity of including IM structure, which was beyond the scope of the work. The potential consequences of this simplification are discussed in Section 5.4.