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Reconciling solar forecasts: Geographical hierarchy

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ABSTRACT

To integrate solar energy into the electricity grid reliably and efficiently, different forecasting techniques are used to produce forecasts at various forecast horizons using data of different levels of aggregation. For example, power generated by distributed photovoltaics (PV) can be disaggregated in a geographical hierarchy into transmission zones, distribution nodes, PV plants, subsystems and inverters; forecasts are required at all of these levels to facilitate different power system operations and power plant management. Due to the different information sets visible to different players in the hierarchy, such as PV plant owners and independent system operators, the forecasts produced at different aggregation levels are often not optimal. Furthermore, these forecasts are aggregate inconsistent, i.e., forecasts made using data collected at lower levels do not add up exactly to the forecasts made using higher level data.

In this paper, the state-of-the-art forecast reconciliation techniques are explored. By minimizing the trace of forecast error covariance matrix, the base forecasts obtained across the hierarchy can be optimally reconciled. The reconciled forecasts not only aggregate consistently, and thus lead to collaborative decision making, but also improve the base forecasts at each level significantly. The merit of the reconciliation framework goes to the fact that it does not require any additional information other than those base forecasts. Furthermore, forecast improvements are independent of the base forecasting methods. In other words, once the base forecasts are generated with our favorite methods, the reconciliation will most likely improve those forecasts further.

The reconciliation techniques can be applied to a variety of hierarchies with different forecast horizons. The empirical part of this work considers two examples, namely, an NWP-based day-ahead forecast reconciliation over 318 simulated PV plants in the state of California, and a spatio-temporal statistical 1-min-ahead forecast reconciliation over 17 irradiance sensors on the Oahu Island, Hawaii. It is shown that reconciliation benefits both the gird operators and PV system owners by bringing more accurate forecasts, and thus motivates information sharing in an electricity grid.

1. Introduction

Grid penetration level of solar energy increases rapidly, especially in locations with rich solar resources, such as the states of California and Hawaii. The state of California government has established a statewide goal to significantly mitigate the greenhouse gas emissions through an aggressive renewables portfolio standard (RPS). The RPS which began in 2002, requires 33% and 50% renewable energy integration in 2020 and 2030, respectively. Due to their extreme dependency to the weather condition causing high variabilities and uncertainties, such aggressive increase in the penetration of renewable energy resources including solar energy is prone to diminishing the power system reliability remarkably. To prevent these adverse effects of integration of high penetrations of renewable energy in electric grid, power system operators are urged to develop reliable solutions to address high variabilities of such energy resources.

Making forecasts at different forecast horizons using data with different time granularities has been a key issue in integrating variable solar energy into electricity grids. A recent study by the National Renewable Energy Laboratory (NREL) on the impact of improved solar forecast on power system operation in Independent System Operator–New England (Martínez-Anido et al., 2014) shows that a 25% PV penetration would reduce the net generation cost in ISO-NE by 22.9% if the solar forecast is perfect. However, the

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cost reduction would be as low as 12.3% with the current forecast techniques, and a 25% improvement in solar forecast would lead to an additional 1.56% ($46.5 M) reduction in net generation cost.

From an electricity grid operator's point of view, the above-mentioned forecasts are associated with and used in various power system operations. Makarov et al. (2011) provided an overview of California independent system operator (CAISO)'s operating practice. The CAISO operating time lines can be grouped into three schedules, namely, generation schedule in the day-ahead market (DAM), schedule in the real-time market (RTM) and schedule for real-time regulation process. In the DAM, hourly day-ahead forecasts are generated (for both load and renewable energy generation) at 10 A.M. the day prior to the operating day. In the real-time market, two types of forecasts are needed: (1) 5 h of 15 min forecasts are performed at 75 min before the actual beginning of an operating hour for short-term unit commitment, and (2) 65 min of 5 min forecasts are needed at 7.5 min before the operating hour for real-time economic dispatch. Lastly, the real-time regulation process requires a 4 s forecast.

For all these operation timescales practiced by CAISO, the spatial forecast accuracy benefits CAISO's power market clearing process by providing more details on the power injected by solar panels to different buses of the power grid. As of now, CAISO just uses the forecasts of renewable energy resources from its different electric regions to run its market clearing process. As the position of the renewable energy resources and their individual power injection to the grid has significant effect on power loss and voltage profiles, any increase in the geographic resolution of such forecasts will enable the market operator to consider more details in its unit commitment and optimal power flow optimization problems. This combined with any enhancements of forecast accuracy will obviously improve the reliability of the market results for the real operation of the power system and will reduce the difference between the DAM and RTM results due to forecast errors. Therefore, the costs associated with dispatching expensive, fast-response generators such as gas turbines in order to fill the gap between DAM and RTM results will be decreased. Further, with the definition of microgrids and virtual power plants (VPP) managed by aggregators and private owners to maximize their benefits or minimize their operation costs, any forecast error will deviate the results of their optimization problem for bidding to the market from what is the their best action to take if the forecast is perfect. Similarly, such deviations make the aggregators and owners to buy more expensive power from RTM in case of under-forecasting and sell their excess power with lower price to RTM in case of over-forecasting. Thus, any improvement in the accuracy of spatial solar forecasts will benefits the microgrids and VPPs by (1) reducing the difference between their DAM and bidding results and (2) enhancing their optimization models to consider the effects of the power networks more precisely, in terms of voltage profile and power loss.

In the recent years, solar energy forecasting techniques have advanced unprecedentedly. The bulk of the literature focuses on developing a particular forecasting approach that is known as "most appropriate" for a forecast horizon. For examples, numerical weather prediction (NWP) is usually developed and validated at a day-ahead forecast horizon (e.g., Perez et al., 2013); satellite data based forecasts are usually performed at an hourly resolution due to the temporal resolution of satellite images (e.g., Voyant et al., 2014); sky camera based approaches (e.g., Yang et al., 2014) perform best at a forecast horizon up to 15 min; correlating measurements from a sufficiently densed sensor network (e.g., Aryaputera et al., 2015b) can forecast accurately for a few seconds to a minute; and machine learning and statistical forecasting techniques are commonly used in intra-hour and hourly forecasting (e.g., Pedro and Coimbra, 2012). For a detailed association of techniques and horizons, the readers are referred to the review by Inman et al. (2013). In addition, the two recent review papers also provide valuable summaries on the state-of-the-art solar forecasting techniques (Antonanzas et al., 2016; Raza et al., 2016).

While the association among forecasting method, spatial scale and forecast horizon has been well understood, the constraint known as "aggregate consistency" is yet to be studied in the solar forecasting context. The solar power injection into an electricity grid can be modeled as a hierarchy, as shown in Fig. 1. The total solar power at any instance in an interconnection can be considered as the sum of the smaller power contributions from each transmission zone, distribution node, power plant and inverter in that interconnection. As mentioned earlier, different players (such as the power system operators and solar power plant owners) in a power system hierarchy produce their own forecasts for various operational needs. While the power in a hierarchy sums up naturally, the forecasts need to be aggregate consistent as well. Nevertheless, the lower level forecasts usually do not add up exactly to the forecasts made at higher levels, due to the different data and forecast methods used by different players in the hierarchy. The disagreement in the forecast numbers hinders power system operations by posing an apparent question: which number should be used? The primary goal of this paper is thus to address the aggregate inconsistency during solar forecasting.

The commonly used methods to produce aggregate consistent forecasts include bottom-up, top-down and middle-out approaches (Athanasopoulos et al., 2009). Bottom-up approach only requires the bottom-level forecasts; the forecasts at upper levels are obtained by summing these bottom-level forecasts. Top-down approach on the other hand starts from making the top-level forecasts; the forecasts at lower levels are then assigned proportionally based on the system size or other features. Lastly, as the name suggests, middle-out approach makes forecasts at a middle level; the upper or lower level forecasts are obtained by aggregate or disaggregate the middle-level forecasts, respectively. Although these methods seem trivial, they are not optimal for hierarchical solar forecasting due to two main reasons. Firstly, it is difficult to transfer forecasts produced at a particular level to other levels. For example, power of distributed PV plants is primarily influenced by moving clouds, only knowing the system size is insufficient to perform the top-down approach. Secondly, different players in the hierarchy are exposed to different information sets that are unobservable by others, but are known to be able to improve local forecasts. For example, power grid operators have historical net load information, which is unobservable by PV plant owners. In view of the above discussion, this paper considers a so-called "optimal reconciliation" technique. This technique considers the independently-made forecasts in a hierarchy simultaneously. By minimizing the trace of forecast error covariance matrix, the forecasts obtained across the hierarchy are optimally reconciled.

On this point, reconciliation should be thought of more as a technique that revises forecasts than a forecasting method. Revising forecasts, also known as forecast post-processing or reforecast, has been studied extensively in solar engineering. Most of the works in the literature focus on revising NWP-based methods due to their known bias (e.g., Verzijlbergh et al., 2015; Pierro et al., 2015; Diagne et al., 2014; Mathiesen and Kleissl, 2011); the technique used in these works is model output statistics (MOS). Besides MOS, other innovations such as the artificial neural network-based reforecast models are also available (Chu et al., 2015). The reconciliation techniques used in this work are conceptually different from the others, however, with no exception, they improve forecast accuracy. Furthermore, as shown in the later sections, improvement on accuracy can be observed on all levels of a