The Value of Improved Wind Power Forecasting in the Western Interconnection

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***Abstract* — Wind is a variable and uncertain energy resource. Wind power forecasts on the day-ahead and hour-ahead timescales allow utilities to predict wind power output and subsequently to incorporate significant penetrations of wind power into their generation mix. Wind forecast errors can be costly and additional reserves are often held to ensure that generation and demand can be properly balanced. Unfortunately, the economic value of wind forecasting schemes, hundreds of which have been proposed, is largely unknown. Only a small number of studies have investigated this topic, many of which supply results tailored to European electrical grids. This paper appraises the value of improved wind forecasting schemes for the entire Western Interconnection. The system used for the Western Wind and Solar Integration Study – Phase 2, the largest study of its kind conducted, is simulated, and the effects of improved wind forecasting under variable natural gas prices, cycling rates, and renewable penetration levels are observed.**

***Index Terms*—forecasting, wind energy, power system analysis computing, power system economics**

NOMENCLATURE

A. Abbreviations

BA	balancing authority
CC	combined cycle
CHP	combined heat and power
CT	combustion turbine
DOE	Department of Energy
ERCOT	Electric Reliability Council of Texas
GE	General Electric
NA	network applications
NMAE	normalized mean absolute error
NREL	National Renewable Energy Laboratory
SCUC/ED	security constrained unit commitment/economic dispatch
WECC	Western Electricity Coordinating Council
WI	Western Interconnection
WWSIS	Western Wind and Solar Integration Study
WWSIS-2	Western Wind and Solar Integration Study Phase-2

The authors recommended that the reader have consistent and easy access to the Abbreviations section in reading this paper.

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I. INTRODUCTION

A. Motivation

Wind power forecasting schemes are varied and often complex. In order for power engineers to commit to integrating new forecast models into their unit commitment and economic dispatch planning, it must be shown that these schemes will provide economic benefits. To date, the economic extent of these benefits is largely unknown to the power community. A cohesive evaluation of improved wind forecasting shall include simulated results obtained from an electrical grid that is of interest to many parties.

The Western Interconnection (WI) is one such grid, encompassing all or portions of 14 of 50 U.S. states, as well as parts of Mexico and Canada [11]. The National Renewable Energy Laboratory (NREL) has simulated the entire WI using a commercial simulation tool called PLEXOS [12], where the WI model was vetted by a broad technical review committee including representatives from GE, NREL, APTECH, RePPAE, utilities, transmission planning groups, WECC, power system experts, fossil-fueld plant experts, and DOE.

This paper assesses the economic value of wind forecasting for the most up-to-date WI model. This paper does not present any improved wind forecasting models; instead, we aim to evaluate the impact of models which are uniformally improved by some percentage from current models. Previous work in valorizing wind forecasts around the world is examined in section I*B.*.

B. Literature Review

Prior work in this area is sparse. Pinson et al. [4] considers Dutch electricity-market characteristics through probabilistic forecasts rather than deterministic forecasts, and its analysis considers only one wind farm and assumes that wind generation has negligible influence on imbalance prices. An interesting result is that regulation costs are reduced when wind power is overestimated rather than underestimated [4]. McGarrigle and Leahy [5] considers the Irish electricity market and finds an average savings of 4.1 million pounds for every percentage point decrease in the normalised mean absolute error (NMAE) between the forecasted wind and actual wind in the 4 to 8% MAE range for the year 2020. That said, the NMAE metric is imperfect, because forecasts having differing distributions of errors may have the same NMAE but could differ significantly in cost, especially during time steps characterized by extreme forecast error. Meibom et al. [6] appraises the value of a perfect forecast for the Irish electrical grid to be 1-65 million euros, finding that value generally increases with increased wind penetration. Tuohy, Meibom, et al. [7] uses an adapted model of that used in [6] and compares stochastic, deterministic, and perfect forecasting; interestingly, this paper includes cases where the demand is not met. Ummels et al. [8] finds minimal cost savings for thermal generation units in the Danish interconnection. This may be attributed to the majority of thermal units being combined heat and power (CHP), which have additional operating constraints.

Various information about the reviewed literature is given in Table 1, from which it is clear that cycling costs, real-time dispatch, and gas price sensitivity have not yet been fully considered. With the above review and Table I in mind, three questions remain unanswered by the examined prior work:

1) What is the value of improved wind forecasts to operators of the Western Interconnection?

2) What is the value of an improved forecast – markedly improved by the same percentage at every sample of the original forecast – at extrema (time steps at which the variance between the forecasted value and actual generation is large)?

3) What is the value of a combined hour-ahead, day-ahead, and real-time unit commitment and dispatch?

These questions are addressed in this paper.

C. *Contributions*

This paper analyzes the value of a 10%, 20%, and perfect forecast for the entirety of the Western Interconnection. NREL's preliminary evaluation for ERCOT by Orwig et. al [10] provided motivating results finding that short-term (0 – 6H ahead) forecast accuracy decreases wind curtailment and energy imbalance prices, as well as system costs. Therefore, a combined day-ahead unit commitment and 4 hour-ahead economic dispatch model is run herein.

Importantly, NREL has previously analyzed the value of uniform wind power forecasting improvements [2] through hourly operation simulations of a WI system, which was designed for the Western Wind and Solar Integration Study (WWSIS) [3]. Since WWSIS, improvements were made to the WI model for WWSIS-2 [1]; most significantly, a new production simulation tool (PLEXOS, also used in [5]) was used to model the WI, which allowed NREL to investigate impacts of wind and solar with 5-minute time step granularity. Additionally, the improved model includes actual 2013 wind forecast error distributions from three BAs representing current forecasting capabilities. It also explicitly includes wear-and-tear costs from cycling. The analysis herein uses this improved WECC model and assesses the value of improved wind forecasting in the WI for a mix of wind and solar generation. Unlike in [2], we investigate the value of improved wind power forecasting for a combined day-ahead/hour-ahead/real-time market and we also examine how this value changes during periods of generator cycling and for different prices of natural gas.

TABLE I
SCENARIOS CONSIDERED BY PRIOR WORK

Author	Hour-Ahead dispatch	Real-Time dispatch	Cycling Costs	Gas Price Sensitivity	Penetration	Grid
Pinson [4]	✓[1]				one farm	Netherlands
McGarrigle [5]	✓	✓	✓[2]		33%	All-Island[3]
Meibom [6]	✓				6-25%	All-Island
Tuohy [7]	✓				34%	All-Island
Ummels [8]	✓				3-33%	Netherlands
Orwig [10]	✓			✓	≈15%	ERCOT

[1]Unlike the other references, which consider deterministic forecasts, Pinson et. al consider hourly probabilistic forecasting. A large-scale modeling tool is not used, as only a single wind farm is considered.

[2]This model includes start costs only.

[3]The All-Island grid is composed of Ireland and Northern Island.

II. Mathematical Formulation

A. *MILP Model*

Unit commitment and dispatch problems are typically solved using mixed-integer linear programming (MILP), a technique for a class of problems having the canonical form

$$\begin{aligned} &\text{minimize} \quad c^T x \\ &\text{subject to } Ax \preccurlyeq b \end{aligned}$$

where $A \in \mathbb{Q}^{m \times n}$, $b \in \mathbb{Q}^m$, $c \in \mathbb{Q}^n$, and $x \in \mathbb{Z}^* \times \mathbb{R}^n$. To use words, c is the column vector of rational coefficients in the objective function, x is the column vector of mixed-integer undetermined decision variables, A is a rational matrix, and b is a right-hand side rational column vector. Together, A and b define the set of equality and inequality constraints in the convex polyhedron $Ax \preccurlyeq b$ over which $c^T x$ is optimized.

B. *Objective Function*

The objective function $c^T x$ minimized in PLEXOS is formulated

$$\text{minimize} \sum_{y \in Y} \sum_{i \in I} [\ldots]$$

PLEXOS iterates through a stochastic optimization process, formulating a deterministic form of the stochastic problem into a MILP akin to that in section IIA.

C. Computation and Optimality

When compared with a PLEXOS run, the WILMAR Scheduling model used by Meibom et al. [6] (also used in [7] in combination with GAMS and Cplex) found a more optimal solution. Meibom et. al's Scheduling model uses a full MILP (Mixed-integer linear programming) formulation, whereas PLEXOS uses an approximated MILP algorithm. Still, solvers may trade-off optimality depending on the characteristics of the problem space, i.e. PLEXOS may find the most optimal solution in another run. It will suffice to say that is known that PLEXOS can compute solutions for large systems with reasonable computation time, and as such it is widely used [13].

III.Case Study Information

To specify the precision of a unit commitment and dispatch simulation model, it's important to present its optimization parameters. The sampling rate and horizon of the reviewed literature is not clear. While [2,4, 10] solve the day-ahead unit commitment at 1 hour time steps, their look-ahead time and resolution is not explicity stated. In [6] and [7], the day-ahead optimization begins at noon and is 36 hours, while the hour-ahead optimization occurs every 3 hours and optimizes until the end of the following day until noon. While [6] states that its model resolution is 1 hour, the look-ahead time is not stated in either [6] or [7].

McGarrigle et. al [5] considers 1-day steps at 30 minute intervals, with each step having a 12 hour look-ahead period. As for real-time dispatch, [5] considers 30 minute real-time optimization at 30 minute intervals, where each step has a 12 hour look-ahead period. However, with the wind data samples from [5] occuring only every 15 minutes and real-time optimization over a lengthy 30-minute time step, it would seem that the model in [5] may not reflect modern real-time dispatch.

Bearing in mind the difficulty in interpreting the methodology of other researchers' simulation models, Table 2 is created to showcase the granularity of the PLEXOS model used in this paper.

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TABLE 2
MODEL GRANULARITY

	Day-Ahead	4 Hour-Ahead	Real Time
Time Step	1 hour	1 hour	5 minutes
Optimization Window	1 day	4 hours	5 minutes
Look-Ahead	1 day	10 hours	n/a[1]
Resolution	4 hours	2 hours	n/a[1]

[1]Real-time computation only considers variable values at that moment.

V.Results

Two scenarios were simulated having identical model parameters; however, Scenario 1 considered a balanced mix of 7% wind and 7% solar and Scenario 2 considered a high wind mix of 18% wind and 4% solar. For each scenario, a forecasting error distribution was assigned to every turbine generated from the average of the forecasting error distributions of three BAs in the WI. The cost, including generation cost and held reserve, is plotted for each scenario given the actual wind forecast, a 10% improved forecast, a 20% improved forecast, and a perfect forecast. The improved forecasts are generated by decreasing the error between the actual and predicted wind generation by that percentage at every sample. Figures 1-8 clearly show the increased precision and decreased cost associated with improved forecasting methods.

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