Wind Power Forecasting in U.S. Electricity Markets[1]

by

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Abstract

Wind power forecasting is becoming an important tool in electricity markets as the amount of wind power rapidly increases. However, the use of wind power forecasting in market operations and among market participants is still at an early stage. We discuss the current use of wind power forecasting in U.S. ISO/RTO markets, and give recommendations for how to make efficient use of the information in state-of-the-art wind power forecasts.

1   Introduction

Wind power generation has increased rapidly in the United States over the last few years, and at the end of 2009 there was more than 35,000 MW of installed capacity at a national level.[1] Wind power is already having a significant impact on the operation of electricity markets and power systems in areas with the highest penetration of wind power, such as in the Electric Reliability Council of Texas (ERCOT) and the Midwest ISO (MISO). A number of challenges arise when integrating renewable generation into the power system, from transmission planning, resource adequacy, and interconnection standards to dealing with the increased uncertainty and variability in short-term operations.[2]

It is generally agreed that forecasting will play an increasingly important role in the operation of power systems as the level of wind power increases. Wind power forecasting models have been continuously improving over the last decade. A number of wind power forecasting providers have emerged that are competing to provide the best forecasts to the electric power industry. There are several different users of the wind power forecasts, including generation companies, wind power producers, utilities, market analysts and traders, and power system and electricity market operators. The desired forecasting capabilities typically vary among user groups. For instance, system operators are particularly concerned with the ability to forecast rapid changes in wind power production, so-called ramping events. Wind power producers, on the other hand, may be more concerned with minimizing their forecasting error over a longer time period to better schedule their resources in the marketplace. Some companies already have considerable experience in the use of wind power forecasting.[3]

In this paper we first give a brief introduction to wind power forecasting models. We then present an overview of the current use of wind power forecasting in U.S. electricity markets, with focus on the ISO/RTO markets that currently have the highest penetration of wind power. Finally, we discuss the need to revise market design to make better use of the information provided by advanced wind power forecasting systems in market operations.

2   Wind Power Forecasting Models

A wind power forecasting system, as illustrated in Figure 1, uses input data from different sources, including results from numerical weather prediction (NWP) models, local meteorological measurements, SCADA data describing the real-time state of the wind power plants, and additional information about the characteristics of the wind power plants and the nearby terrain and topography. Modern wind power forecasting models are usually based on a combination of physical and statistical models. The physical approach describes the physical relationship between atmospheric conditions, local topography, wind speed, and the output from the wind power plant. In contrast, the statistical approach estimates a statistical relationship between all the relevant input data and the resulting wind power generation without considering the physics of the system. The performance of wind power forecasts and the forecast accuracy depends on the availability of good NWP forecasts, the complexity of the terrain, and the availability of real-time weather and wind power plant data. Hence, there can be large differences in forecasting errors between wind power plants at different locations. Wind power forecasting systems typically produce forecasts for a time horizon up to 2-3 days ahead in time. In general, the forecasting error increases with the forecast horizon.
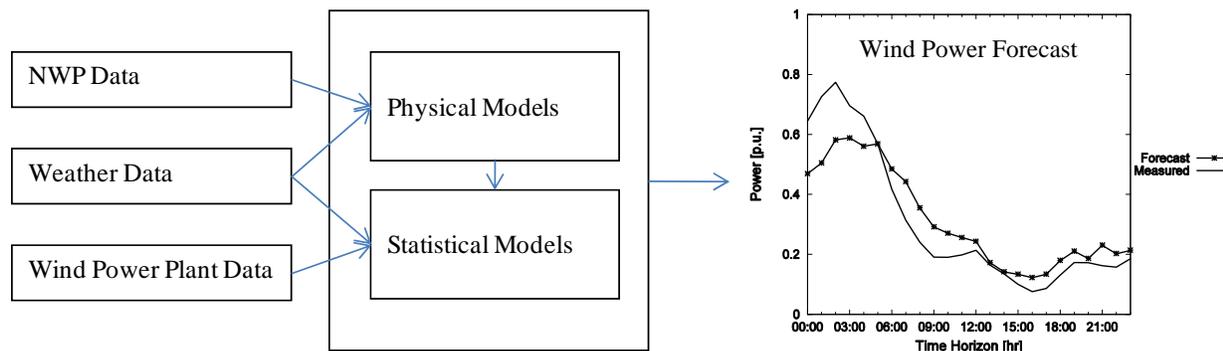

Figure 1. Illustration of wind power forecasting system.

Wind power forecasting models are continuously being improved with the goal of increasing the forecast accuracy. Ongoing research also focuses on producing probabilistic forecasts, because information about the uncertainty in the wind generation can be of great value for system operators and market participants. As an example, Figure 2 shows two different types of uncertainty representation in wind power forecasting. Ramp forecasting is another important area of research. For a detailed review of the current state of the art in wind power forecasting we refer to a recent report by Argonne National Laboratory.[4]
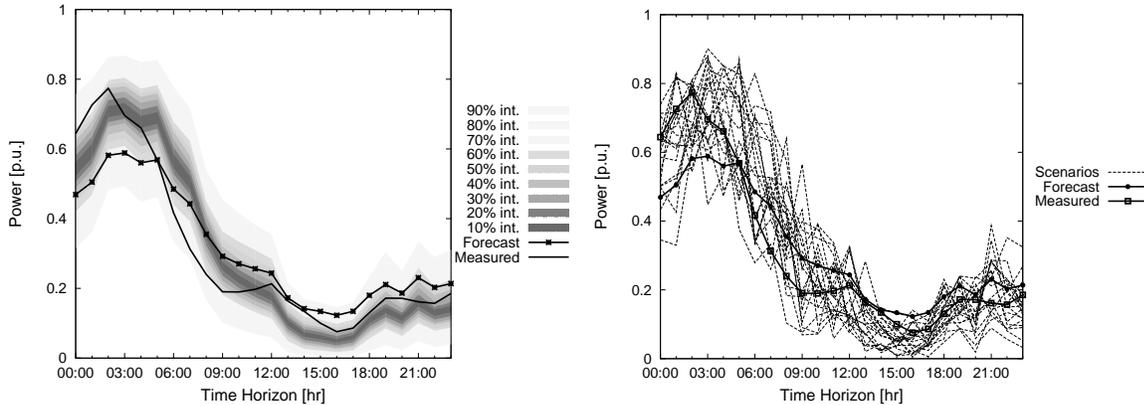
Figure 2. Uncertainty representation in wind power forecasts : a) probabilistically by a set of intervals or quantiles (left), b) scenarios of wind power generation representing the temporal dependency of forecast errors (right).

3   Use of Forecasting in Market Operations

In this section we discuss the potential use of wind power forecasting in the short-term operation of ISO/RTO markets in the United States. The markets in different regions of the country have seen a considerable degree of convergence in market design in recent years. ISO/RTO markets already have several features that are advantageous for the integration of wind power into the electric power system, such as:

1. *Large Balancing Authority Areas* give the system operator the control of generation and demand resources over a larger area, increasing the overall flexibility of the system to handle variations in wind power generation. At the same time, the variation in total wind power generation, and also the wind power forecasting error, generally decreases as a function of geographical size. Each ISO/RTO is operated as one balancing authority area.

2. *Centralized unit commitment and scheduling* of energy and operating reserves gives the system operator control of a large pool of generation and load resources, which can be used to effectively accommodate fluctuations in wind power output. Combined operation of energy and operating reserves markets also ensures cost-efficient and market-based procurement of energy and operating reserves.

3. *Frequent dispatch of resources* in real time. Most ISO/RTO markets re-dispatch the system resources every five minutes, upon which new set-points are sent to generators and eligible demand resources. The frequent system dispatch reduces the need to maintain expensive regulation reserves to respond to short-term fluctuations in load and non-dispatchable generation.

4. *Locational marginal prices (LMPs)* give locational market-based incentives for short-term operation and long-term expansion. LMPs can also enable price-based and efficient curtailment of wind generation during periods with surplus wind power generation, which are typically caused by a combination of transmission bottlenecks and minimum generation limits for thermal power plants. LMPs also provide efficient incentives for location of new wind power generation, taking network congestion into account.

The experience with wind power forecasting, however, is relatively limited so far. A brief summary of the current state of wind power forecasting for MISO, New York ISO (NYISO), PJM, ERCOT, and California ISO (CAISO) is provided in Table 1. A typical timeline for the operation of the electricity market is shown in Figure 3Figure 5. The procedures and timeline in the figure are based on the current rules in the MISO market. However, other ISO/RTO markets are operated in a similar way. The main steps in the market operations, including determination of reserve requirements, day-ahead (DA)

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operations, reliability assessment commitment, and real-time (RT) operations, are discussed below. As indicated in Figure 3, wind power forecasting can play an important role in all of these steps as the wind power penetration increases.
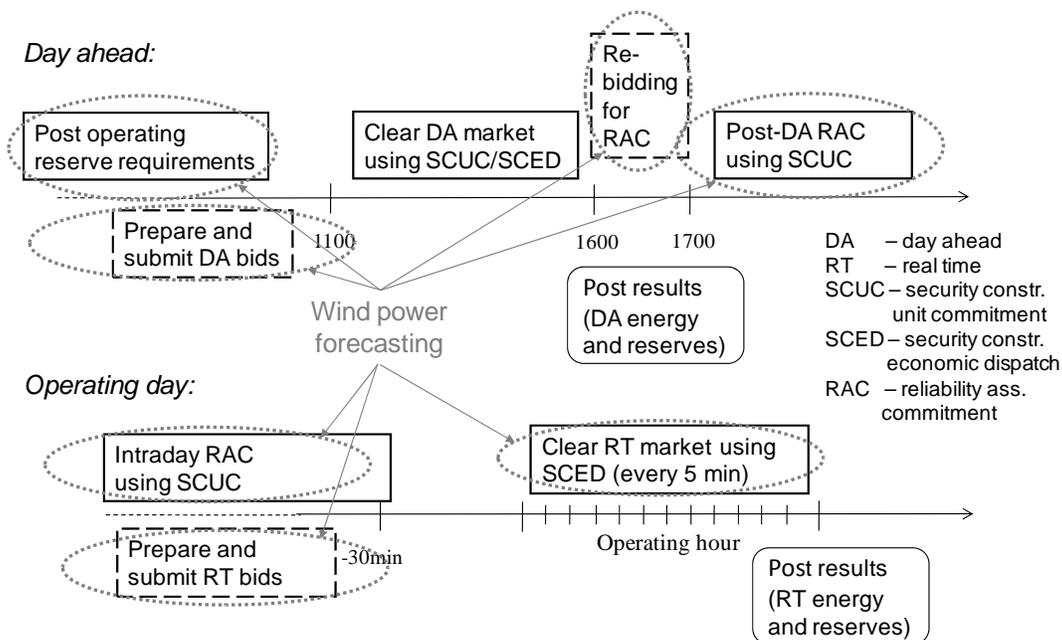

Figure 3. Market operations timeline for MISO, indicating where wind power forecasting could play an important role.

Table 1 Overview of wind power forecasting and market operation in five U.S. electricity markets.[5]

	MISO	NYISO	PJM	ERCOT	CAISO
Peak load	116,030 MW (7/31/2006)	33,939 MW (8/2/2006)	144,644 MW (8/2/2006)	62,339 MW (8/17/2006)	50,270 MW (7/24/2006)
Total installed capacity	Ca. 138,000 MW	Ca. 38,000 MW	Ca. 165,000 MW	Ca. 80,000 MW	Ca. 59,000 MW (incl. imports)
Wind capacity (end of 2009)	Ca. 7,600 MW	Ca. 1,300 MW	Ca. 2,500 MW	Ca. 9,000 MW	Ca. 3,000 MW
Wind power forecasting	In operation since 2008: • DA and intra-day RAC • Transmission security and outage coordination • Transmission security and peak load analysis • Indication of ramps	In operation since 2008: • Reliability assessment commitment at DA stage • RT commitment and dispatch • Ramping alert system under consideration	In operation since 2009: • DA transmission security and reserve adequacy assessments • Developing automated procedures • Specific ramp forecast	In operation since 2008: • 80% exceedance forecast used for DA planning • To be fully integrated in new nodal design, to be introduced end of 2010 • Developing ramp forecast	In operation since 2004: • Used to calculate energy schedule in RT market • Advisory role in DA market
Market timeline	DA bids due: 11 a.m. DA results: 4 p.m. Re-bidding due: 5 p.m. RT bids due: OH -30 min	DA bids due: 5 a.m. DA results: 11 a.m. RT bids due: OH -75 min	DA bids due: noon DA results: 4 p.m. RT bids due: 6 p.m. (DA)	DA bids due (reserves only): 1p.m/4 p.m. DA results: 1:30p.m/6 p.m. RT bids due: OH -60 min	DA bids due: 10 a.m. DA results: 1 p.m. RT bids: OH -75 min

Wind power bidding, dispatch, imbalance settlements, deviation penalties	• If wind is a capacity resource it must bid in DA market and RAC • No deviation penalties • No wind dispatch, but this is being considered	• Wind required to bid in RT market. DA bidding optional • Dispatch signals provided from SCED • Penalty for over-generation in constrained situations • No penalties for under-generation	• If wind is a capacity resource it must bid in DA market • Deviation charges apply • Wind dispatch signals provided in constrained situations	• Bilateral market • Imbalances settled at RT zonal energy price • Penalty exemption for +/- 50% of scheduled generation • Ramping limits	• Wind program participants' RT bid based on ISO forecast. Deviations netted over month at average price • 10-min imbalance charges for nonparticipants • Wind is not dispatched

Key: DA = day-ahead, OH = operating hour, RAC = reliability assessment commitment, RT = real time, SCED = security-constrained economic dispatch

3.1 Operating reserve requirements

The requirements for operating reserves in U.S. power systems are based on standards determined by the North American Reliability Council (NERC 2009).[6] Operating reserves are categorized into several types depending on how quickly they can respond to changes in the system (Figure 4). The regulating reserve responds immediately to balancing needs in the system, and is usually provided by generating units with automatic generation control (AGC) responding to frequency deviations in the network.

Contingency reserves are used to respond to contingencies that may occur, such as forced outages of generators or transmission lines. The contingency reserve can be split into spinning and non-spinning reserves, where the spinning component needs to be able to respond within 10 minutes. It is common that both generation and demand resources can provide contingency reserves. In the event that operating reserves need to be used due to a contingency in the system, the required level of reserve must be restored as soon as possible and at least within 60 minutes.[7]
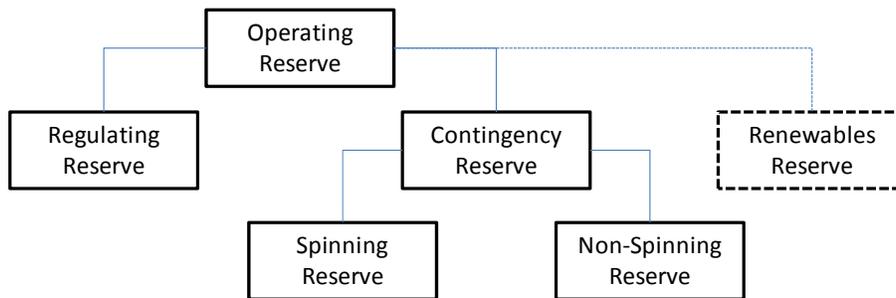

Figure 4 Traditional operating reserve categories as defined by NERC and a proposed new category to address increased uncertainty and variability from renewable generation.

The ISO/RTOs are required to maintain sufficient regulating reserve to meet NERC's criterion for area control error.[8] The requirement for contingency reserves is based on the N-1 rule, i.e that sufficient contingency reserve must be held to cover "the loss of generating capacity due to forced outages of generation or transmission equipment that would result from the most severe single contingency." At least half of the contingency reserve must be spinning. These are the minimum requirements set by NERC; however, regional variations exist and some ISO/RTOs use more stringent requirements for their operating reserves. In systems with large and congested networks, it is common to specify regional reserve requirements in addition to the system-wide criteria. It is also interesting to note that some markets have introduced a demand curve for different types of operating reserves rather than the traditional fixed requirements. Operating reserve requirements may be updated to accommodate changes

in the system conditions. The update frequency varies between different markets (seasonal, monthly, and daily updating), but the requirements for the next operating day must at least be posted before operation of the DA market begins.

The additional uncertainty and variability caused by an increasing penetration of wind power generation raises the question of whether current requirements for operating reserves are adequate. In general, wind power forecasting can guide the procurement and use of the operating reserves by increasing the system operators' knowledge of projected wind power generation and therefore the overall balance between supply and demand in the system. Several improvements to existing requirements and procedures are relevant, including:

1. *New definitions of operating reserve requirements* that better reflect the needs in power systems with a large share of renewable energy. For instance, changes in wind power output unfold much more slowly than the traditional contingencies, which are caused by sudden equipment failures. Hence, the system operator has more time to respond to these changes, and a slower type of reserve than the current contingency reserves (at least slower than the current spinning reserves) may be sufficient. At the same time, it is less critical to replace these reserves immediately, as a second down-ramp event is not likely, and oftentimes not even possible, if there has already been one major reduction in wind power generation. An additional type of "renewables reserve" is therefore proposed in Figure 4. Such a reserve category would have slower response and restoration times and so should be less expensive than the traditional contingency reserves. There is also likely to be a need for additional regulation reserves. However, the short dispatch intervals reduce the need for regulation to handle short-term variability in wind generation. Better short-term wind power forecasts would also limit the amount of regulation reserves needed.

2. *Improved determination of reserve requirements* to better accommodate the characteristics of wind power and other renewable generation. Traditional deterministic criteria (e.g., loss of the largest unit in the system) should be replaced with probabilistic approaches that directly reflect the uncertain nature of supply and demand. Ideally, probabilistic wind power forecasts should be used in the calculation of improved reserve requirements that account for the risk of losing load due to wind generation forecast errors in addition to forced outages and unexpected changes in load. The historical forecasting errors should also be taken into account. Ongoing research looks at probabilistic determination of optimal spinning reserve criteria[9] in systems with high wind power capacity, as well as demand curves for operating reserves.[10]

3. *Dynamic and frequent updating of operating reserve requirements* based on the most updated system information, including the most recent wind power forecast. This will result in better informed decisions, and thus in more efficient operations. More frequent updating of reserve requirements would enable operating reserves to be adjusted according to how much wind generation is forecasted for the next hours and days, as well as the projected uncertainty in the forecast.

Several ISO/RTOs are currently considering the need to change their procedures and requirements for operating reserves. ERCOT, which is the ISO/RTO with the highest level of wind power capacity in the United States (Table 1), is already considering wind power penetration and forecasting uncertainty in their determination of requirements for regulation and non-spinning reserves.[11] In a recent study of the ancillary services requirements in ERCOT,[12] GE recommends that ERCOT makes adjustments to its procedures as the level of wind power generation increases. They point out the importance of making better use of forecasting in the procurement of different types of operating reserves, and that the level of reserves should be adapted to actual conditions.

3.2   Day-ahead operations

The deadline for market participants to bid into the DA market varies between different ISO/RTOs, as shown in Table 1. The bids of the market participants must reflect how much energy and operating reserves they can provide. Information on unit commitment constraints (e.g., ramping rates, startup costs/times, minimum down-times, etc. for generating units), self-scheduling, and bilateral schedules is also provided to the ISO/RTO.

The clearing of the DA market is a two-stage procedure in most markets. First, a security constrained unit commitment (SCUC) is run to commit resources. Second, a security-constrained economic dispatch (SCED) algorithm is run based on the commitment schedule from the SCUC. Transmission constraints may be simplified or omitted from the SCUC formulation to solve the problem in a reasonable time. In contrast, the transmission constraints are always included in the SCED formulation, although usually with a simplified linear representation (DC-OPF). In most U.S. markets, the SCUC/SCED procedure co-optimizes energy and operating reserves. The output from the DA market clearing therefore includes schedules for energy and operating reserves. In addition, LMPs are derived for each transmission node, and market clearing prices are also calculated for each category of operating reserves.

In the United States, about 70% of the installed wind power through 2008 was sold through Power Purchasing Agreements (PPAs), mainly to utilities.[13] Most of the wind power generation is therefore not being bid directly into the DA market by the wind power producers, but is rather integrated into the utilities' scheduling plans along with loads and other generating resources. It is therefore hard to estimate to what extent wind power forecasts are taken into account in the bids and schedules submitted into the DA market. In many cases, wind power generation is first being dispatched in the RT market. This may be one of the reasons why RT prices currently tend to be lower than DA prices in areas with large wind penetration[14]. Wind power producers may therefore benefit from using wind power forecasts to bid into the DA market and thereby receive a higher and less volatile price.[15]

It is important to integrate the information in wind power forecasts into the DA market clearing. Wind power will have an increasing impact on the marginal cost of electricity and this should be properly reflected in the DA market clearing, where most of the energy is settled. For the DA market to reflect the expected RT conditions as closely as possible, it is important that the market participants have the right incentives to provide the best possible wind power forecast information through their bids. Since the DA operation should be market-driven and based on the market participants' schedules and bids, the system operator should not use its own forecast to directly represent wind power generation in the SCUC/SCED procedure in the DA market. The system operators' forecast information should still be reflected in the operating reserve requirements, as discussed above, and in this way would also influence the market results.

One way to encourage participation of wind power generation in the DA market would be to reduce the time period between DA bidding and RT operations. The due times for DA bids vary among markets, but are at least 12 hours before the start of the operating day (Table 1). By shortening the time period and possibly introducing additional markets between DA and RT, the market participants, and particularly the wind power producers, could clearly make better use of forecast information, as the forecast error decreases with a shorter time horizon. It is also important to avoid situations in which market participants are incentivized to submit biased DA bids. As an example, the ERCOT market used to have protocols that unintentionally gave wind power producers in some areas incentives to over-schedule, due to allowances for uninstructed deviations combined with rules for congestion management.[16] In the Iberian electricity market (Spain and Portugal), asymmetric deviation penalties make it more attractive for wind power producers to bid above their expected generation.[17]

3.3 Reliability assessment commitment

After the clearing of the DA market and before the start of the operating day, the ISO/RTO usually performs a revised commitment procedure, with more focus on reliability. The so-called reliability assessment commitment (RAC) is also performed using SCUC. However, at this stage the demand bids which were used to clear the DA market are replaced with the forecasted load for the next day. The ISO/RTO may therefore decide to change the commitment schedule from the DA market clearing based on the results from the RAC. The RAC procedure may take place according to a fixed time schedule or whenever the system operator finds it necessary to consider system re-commitment, due to unexpected operating conditions (forced outages, deviations from forecasted loads, etc.). Rules are typically in place to make sure that generating resources committed in the RAC recover all their operating costs. This may sometimes require make-whole side-payments in addition to the regular payments based on the market clearing prices, in order to recover all costs (including no-load costs, start-up costs, etc.).

ISO/RTOs are currently focusing on how to integrate the information in wind power forecasts into the RAC. In contrast to the DA market clearing, the system operator can now use its own forecast information directly as input to the SCUC. Hence, both demand and wind power bids/schedules are replaced with the system operators' own forecast information in order to ensure reliable operation. An important question is how to consider the additional uncertainty from wind power at this stage in the market operation. One can address the uncertainty and variability from wind power by adjusting and increasing the operating reserve requirements, as discussed above. However, the treatment of wind resources in the RAC will also influence how much other generation capacity is committed and available to accommodate the predicted and unpredicted system variability.

An interesting approach is taken by ERCOT, which is currently using an 80% exceedance forecast[18] for wind power generation as input to its DA resource planning procedures.[19] ERCOT is considering using the same type of forecast in the RAC as the nodal market system is introduced. In reality, using a conservative projection of wind power means that more capacity is committed than what would be the case if the mean or median forecast were used. Hence, the resulting security margin may increase the reliability of the system, but repeated over-commitment would result in inefficient operations.

An alternative way to address the uncertainty from wind power generation is to use a stochastic formulation of the unit commitment problem. Several different approaches have been proposed in recent literature to address uncertainty from wind power generation in the unit commitment problem.[20] Preliminary results indicate that stochastic models can contribute to reducing costs while maintaining system security under increased uncertainty and variability. However, more research is needed into developing and testing stochastic models for unit commitment, and to evaluate their real-world applicability for system and market operations. In particular, is important to generate consistent and representative information about the forecast uncertainty for use in such stochastic models. It is also important to consider the close interaction between the operating reserve requirements and the unit commitment policy because they both influence the level of committed and available capacity. An important consideration is that while capacity committed as operating reserve receives reserve payments, additional capacity committed in the RAC is likely to receive make-whole side payments to recover costs, as pointed out above. The required level of capacity should be achieved in the most cost-efficient manner.

Another potential application of a wind power uncertainty forecast at this stage in the market operation is in congestion management analysis to assess the risk of congestion in some network branches and perform corrective measures to hedge against a higher risk of congestion.[21]

3.4   Real-time operations

Market participants can bid their remaining resources into the RT market. The deadline for submitting bids to the RT market varies quite widely between different markets (Table 1).[22] During the operating hour, the ISO/RTO uses SCED to dispatch the system on the basis of the committed capacity in the system after the DA and RAC operations have been completed. At the same time, RT prices for energy (LMPs) and operating reserves are calculated. Conventional power generation sources are penalized if they deviate from their RT dispatch signals. Until recently, however, renewable generation such as wind power has not been given dispatch signals from the ISO/RTO and has typically been dispatched as a price taker in the RT market. Wind power generation also has exemptions from RT deviation penalties in most markets (Table 1).

ISO/RTOs are currently working on improving the integration of wind power into their RT dispatch procedures. Short-term wind power forecasts, which have relatively low uncertainty, should be taken into account in the ISO/RTOs' RT SCED. At the same time, it is important that the ISO/RTO is able to control the generation from wind power plants and enforce curtailment of wind power generation in situations where this is needed, either from an economic or reliability perspective.[23] CAISO is requiring wind power plants in the Participating Intermittent Resource Program (PIRP) to bid into their hour-ahead market according to CAISO's short-term wind power forecast. Rules are also in place to limit the deviation penalties for wind power (Table 1).

NYISO recently introduced new rules to incorporate wind power in its SCED.[24] With the new rules, wind power plants will be required to bid into the RT market. A price-bid is offered into the market based on the wind power producer's preference, whereas the bid quantity is determined by the system operator's short-term wind power forecast. During unconstrained hours, wind power plants can operate freely. However, in constrained situations wind power plants are directed to curtail their output when the clearing price at their location falls below their economic bid. Penalties are in place for exceeding the dispatch instructions. The new procedure makes sure that the economic preferences of the wind power producers are reflected in the SCED. It also contributes to a more efficient dispatch overall, and reduce the need for using out-of-market actions to maintain system reliability. PJM has also introduced a scheme for RT dispatch of wind power plants based on their bids. Other ISO/RTOs should consider similar measures to improve the handling of wind power resources in the RT dispatch.

4   Summary and Conclusions

Wind power forecasting is an important tool to improve the efficiency and reliability of power systems with a large share of wind power. ISO/RTOs in the United States are currently working on integrating wind power forecasts into their operating procedures, and wind power forecasting is already used for a number of important applications.[25] However, as the amount of wind power capacity is rapidly increasing, there is a need to better integrate wind power forecasting into different parts of electricity market operations, from DA scheduling to RT operations. It is also important to design electricity markets that give market participants the opportunity and right incentives to provide their unbiased forecast information through their scheduling and bidding.

Figure 5 summarizes how we foresee that wind power forecasting will play important roles in the main steps in electricity market operations. ISO/RTOs and market participants will need to develop new tools and procedures to make efficient use of the forecast information with the overall goal of making better operational decisions under the increased uncertainty and variability from wind power and other sources of renewable generation. A key challenge is therefore to improve decision making under uncertainty and the understanding of the impact of uncertainty on operational decisions (such as unit commitment). At the same time, it is important to continue the improvements of wind power forecasting models, and to better

tune them to the specific needs of the forecast users. For electricity market operators it is particularly important to improve predictions of forecast uncertainty and ramping events.
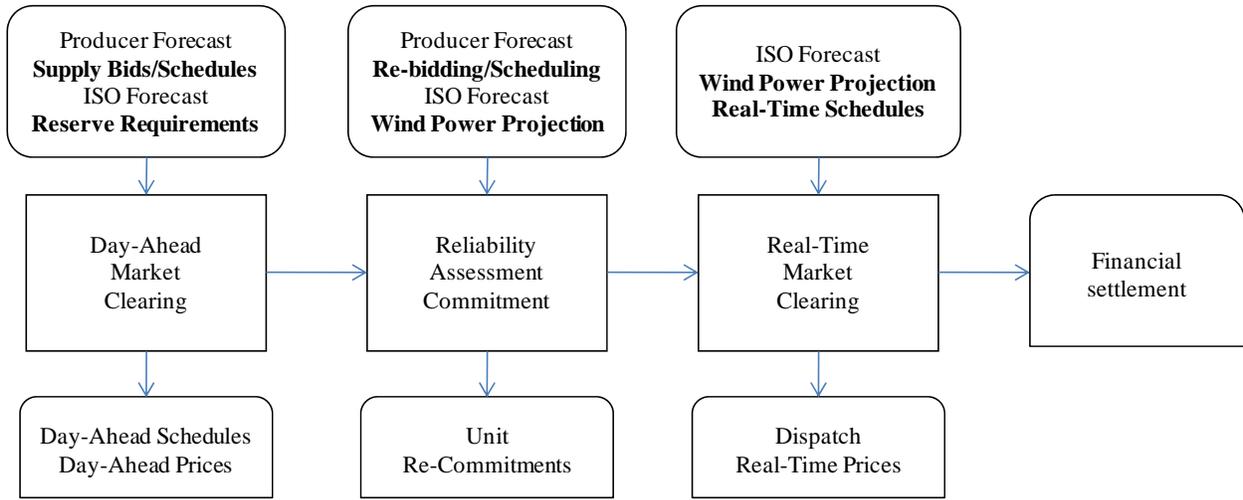

Figure 5 Role of wind power forecasting in electricity market operations.

Acknowledgment

[1] American Wind Energy Association, www.awea.org.

[2] Many of these challenges are discussed in NERC's report "Accommodating High Levels of Variable Generation," April 2009, and the U.S. Department of Energy's report, "20% Wind Energy by 2030: Increasing Wind Energy's Contribution to U.S. Electricity Supply" July 2008.

[3] Descriptions of experiences with wind power forecasting so far can be found in: W. Grant, D. Edelson, J. Dumas, J. Zack, M. Ahlstrom, J. Kehler, P. Storck, J. Lerner, K. Parks, C. Finley, "Change in the Air: Operational Challenges in Wind-Power Production and Prediction," *IEEE Power & Energy Magazine* 7(6): 47-58, 2009; B. Ernst, B. Oakleaf, M.L. Ahlstrom, M. Lange, C. Moehrlen, B. Lange, U. Focken, K. Rohrig, "Predicting the Wind," *IEEE Power & Energy Magazine* 5(6): 78-89, 2007; M. Ahlstrom, L. Jones, R. Zavadil, W. Grant, "The Future of Wind Forecasting and Utility Operations: Planning for Improved System Operations," *IEEE Power & Energy Magazine* 3(6): 57-64, 2005.

[4] C. Monteiro, R. Bessa, V. Miranda, A. Botterud, J. Wang, G. Conzelmann, "Wind Power Forecasting: State-of-the-Art 2009," Report ANL/DIS-10-1, Argonne National Laboratory, November 2009. Available at: www.dis.anl.gov/projects/windpowerforecasting.html.

[5] Based on information from the Utility Wind Integration Group (UWIG) and ISO/RTO information material.

[6] North American Reliability Council (NERC), "Reliability Standards for the Bulk Electric System of North America," NERC, April 2009. Available at: www.nerc.com/page.php?cid=2|20.

[7] Ibid.

[8] The Area Control Error is a measure for the deviation between scheduled and realized exchange from a balancing authority area and is defined by NERC as "the instantaneous difference between net actual and scheduled interchange, taking into account the effects of Frequency Bias including correction for meter error."

[9] M.A. Ortega-Vazquez, D.S. Kirschen, "Estimating the Spinning Reserve Requirements in Systems With Significant Wind Power Generation Penetration," *IEEE Trans. on Power Systems* 24(1): 114-124, 2009; and M.A. Matos, R. Bessa, "*Operating Reserve Adequacy Evaluation using Uncertainties of Wind Power Forecast*," Proceedings 2009 IEEE PowerTech Conference, Bucharest, Romania, 2009.

[10] W.W. Hogan, *A Model for a Zonal Operating Reserve Demand Curve*, MIT Operations Research Seminar, October 15 2009. Available at: www.whogan.com/.

[11] Electricity Reliability Council of Texas (ERCOT), "ERCOT Methodologies for Determining Ancillary Service Requirements," ERCOT, December 2009. Available at: www.ercot.com/mktinfo/services/.

[12] General Electric, "Analysis of Wind Generation Impact on ERCOT Ancillary Services Requirements," GE Report, March 28, 2008. Available at: www.uwig.org/opimpactsdocs.html.

[13] R. Wiser, M. Bolinger, "2008 Wind Technologies Market Report," Lawrence Berkeley National Laboratory, July 2009. Available at: http://eetd.lbl.gov/EA/EMS/reports/2008-wind-technologies.pdf.

[14] As an example, within the MISO footprint in 2009 the average RT prices in parts with substantial amount of wind energy (like North Dakota, Iowa, and Illinois) were as much as 5% lower than average DA prices. The difference between DA and RT prices was only 1–2% in the eastern part of the MISO footprint, which has less wind.

[15] By using wind power forecasting for scheduling and bidding, wind power producers may also reduce their exposure to negative prices and lower their imbalance penalties (if such penalties exist). In addition, wind power forecasting can play an important role in maintenance planning.

[16] R. Sioshansi, D. Hurlbut, "Market protocols in ERCOT and their effect on wind generation," *Energy Policy* (in press).

[17] H. Bludszuweit, "Reduction of the uncertainty of wind power predictions using energy storage," PhD thesis, Universidad de Zaragoza, Spain, July 2009.

[18] This means that there is an 80% chance that the actual wind power generation will exceed the forecast.

[19] D. Maggio, "Integrating Wind Forecasting into Market Operation – ERCOT," Presentation Wind Forecasting Workshop, Utility Wind Integration Group (UWIG), Phoenix, AZ, February 2009.

[20] See for instance R. Bart, H. Brand, P. Meibom, C. Weber, "A Stochastic Unit-commitment model for the Evaluation of the Impacts of Integration of Large Amounts of Intermittent Wind Power," *Proceedings 9th Int. Conf. on Probabilistic Methods Applied to Power Systems*, Stockholm, Sweden, 2006; F. Bouffard and F. Galiana, "Stochastic security for operations planning with significant wind power generation," *IEEE Transactions on Power Systems* 23(2): 306-316, 2008; J. Wang, M. Shahidehpour, and Z. Li, "Security-constrained unit commitment with volatile wind power generation," *IEEE Transactions on Power Systems* 23(3): 1319-1327, 2008; P.A. Ruiz, C.R. Philbrick, and P.W. Sauer, "Wind Power Day-Ahead Uncertainty Management through Stochastic Unit Commitment Policies," *Proceedings Power Systems Conference and Exhibition*, Seattle, March 2009; A. Tuohy, P.

Meibom, E. Denny, and M. O'Malley, "Unit Commitment for Systems With Significant Wind Penetration," *IEEE Transactions on Power Systems* 24(2): 592-601, 2009; J. Wang, A. Botterud, G. Conzelmann, V. Miranda, C. Monteiro, G. Sheble, "Impact of Wind Power Forecasting on Unit Commitment and Dispatch," *8th Int. Workshop on Wind: Large-Scale Integration of Wind Power into Power Systems*, Bremen, Germany, October 2009.

[21] J. Usaola "Probabilistic load flow in systems with wind generation," *IET Trans. on Generation, Transmission and Distribution*. Available at: http://dx.doi.org/10.1049/iet-gtd.2009.0039.

[22] Some ISO/RTOs, like NYISO and CAISO, also have a formal hour-ahead market clearing procedure.

[23] Modern wind power plants include a number of features that make them more similar to conventional power plants, including reactive power contribution, voltage regulation, disturbance ride-through, grid frequency response, smoothing wind ramps, and controlled startup/shutdown.

[24] R. Gonzales, R. Mukerji, M. Swider, D. Allen, R. Pike, D. Edelson, F. Nelson, J. Adams J., *Integration of Wind into System Dispatch*, New York ISO White Paper, Oct. 2008. Available at: www.nyiso.com/public/webdocs/documents/white_papers/wind_management_whitepaper_11202008.pdf.

[25] More information on the status of the integration of wind power and forecasting in U.S. ISO/RTOs is provided by the Wind Integration Group (UWIG) in *Wind Power and Electricity Markets*, August 2009, and *Central Wind Power Forecasting Programs in North America by Regional Transmission Organizations and Electric Utilities*, December 2009. Available at: http://www.uwig.org/.