Electricity Market and Operations Reliability

Mingguo Hong, *Member, IEEE*, Kimberly Sperry, *Member, IEEE*, John Williams and Joe Gardner

***Abstract*—As the main power system interconnections in North America have undergone changes toward the market economic structure, ensuring grid reliability has become the responsible of the Regional Transmission Organizations (RTOs). In market economy, operations planning works side-by-side with the market to achieve grid operation reliability. Operations planning identifies reliability requirements to be enforced in the market clearing processes. It also provides outside-the-market mitigation strategies for system conditions that are not effectively addressed by the market clearing process. The RTO must maintain a correct balance to avoid both the "under planning" and the "over planning". The former jeopardizes the grid reliability. And the latter results in poor market economic efficiency. This paper reviews the Midwest ISO market and operations planning business processes. It also discusses sensitive areas of operation where the correct balance is harder to achieve, but its success would significantly impact the market economics, in terms of both operation cost and pricing.**

***Index Terms*—Electricity market, operations planning, power systems, Regional Transmission Organizations (RTO), reliability.**

I. Nomenclature

AC: Alternating Current
ACE: Area Control Error
AGC: Automatic Generation Control
DC: Direct Current
EMS: Energy Management Systems
FRAC: Forward-Day Reliability Assessment Commitment
IRAC: Intra-Day Reliability Assessment Commitment
LMP: Locational Marginal Price
MCP: Marginal Clearing Price
MIP: Mixed Integer Programming
MW: Mega-Watts
NERC: North American Electric Reliability Corporation
NSI: Net Scheduled Interchange
RC: Reliability Coordination
RTO: Regional Transmission Organizations
SCED: Security Constrained Economic Dispatch
SCUC: Security Constrained Unit Commitment
TSP: Transmission Security Planning

II. Introduction

Modern power systems are large interconnected AC circuit networks that are designed to produce and deliver electrical power from generation resources to end customers. Today as many critical functions of society are dependent on the uninterrupted supply of electricity, reliable operation of the power system grid has become increasingly important. Meanwhile, significant portions of the power system interconnections in North America have developed market mechanisms to support the reliable operations of the power grid. Ensuring grid reliability in these areas has become a significant responsibility of the Regional Transmission Organizations (RTO), who plays the role of both grid operator and market administrator.

Regardless of the economic structure, grid reliability has been evaluated and ensured from two basic aspects, as described by the NERC standards: adequacy and security. Adequacy refers to the grid's ability to supply customer electrical demand and energy requirements at all times, considering both scheduled and reasonably expected unscheduled outages. Security refers to the system's ability to withstand sudden disturbances such as short circuits or unanticipated equipment loss. From an operation's perspective, grid reliability is evaluated based on the system's operating reserve margin, transmission security, and its real-time load balancing capability through the automatic generation control (AGC).

In grid operation, achieving reliability has always depended on successful operations planning. In the vertically integrated industry, operations planning works within well known parameters in smaller structures and the results of operations planning studies often directly lead to operational decisions. In a market structure, operational decisions are made based on offers made by market participants that may not be well coordinated with reliability objectives and it is essential that market signals provide incentives that will result in reliable outcomes. Ideally, these signals are communicated via price signals that reflect the underlying state of the power system. In addition, processes to ensure reliability are also necessary as a back-stop to market behavior in order to ensure grid reliability. Operations planning utilizes both market participant information as well as known electric grid electrical topological forecast conditions in order to ensure reliable market outcomes. Additionally, operations planning identifies any reliability requirements that have not been fulfilled by market outcomes and determines additional actions necessary to ensure operational objectives are met. Ideally, these processes also are conducted within parameters that achieve cost effective outcomes.

In principle, a good market design will achieve reliable operations through its clearing processes and operations planning will have little involvement in changing these market outcomes. Maintaining a proper balance, however, has been a challenge for the RTO who is under uncompromised

The authors are with the Midwest ISO, Carmel, IN 46032 USA. Their e-mail addresses are: mhong@misoenergy.org, ksperry@misoenergy.org, jwilliams@misoenergy.org, jgardner@misoenergy.org.

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obligation to meet the reliability standards and may operate very conservatively in coping with future uncertainties.

This paper reviews the market and operations planning business processes that take place at the Midwest ISO. The operations planning process is designed so that sufficient preparations for operation reliability are made without unnecessary intrusion to the market responsibilities. Difficulties do arise due to the uncertainties about the system future operating conditions, or when the hour of operation is in the near future. The discussion further identifies key areas where the performance of planning has significant impact on the market economics, in terms of both production cost and pricing. Finally, the paper discusses the operations planning challenges involving renewable energy resources.

The discussion in this paper has been based on the market design and operational experience of the Midwest ISO. The Midwest ISO is an RTO that operates one of North America's largest electricity markets and has operated both a Day-Ahead and a Real-Time energy market since April of 2005. Since January of 2009, the Midwest ISO has incorporated ancillary services into its existing energy wholesale market, and simultaneously became a single balancing authority for its market footprint. The ancillary services market is designed to achieve minimum production cost by co-optimizing the market offers of both energy and operating reserves on a five minute basis.

This paper has been one of few reports among the power engineering publications that provide a comprehensive overview of the operation reliability implementations under the market economic structure of an RTO. A relevant discussion concerning the PJM market is found in [3].

III. The Midwest ISO Market System

Economic efficiency and power system reliability are two primary objectives of the system operation at the Midwest ISO. The Midwest ISO's wholesale electricity market is a two-settlement market system that consists of both a day-ahead market and a real-time market. This market design allows most market activities and settlement to take place on the day prior to operation, in the day-ahead market. The real-time market, while clearing independently of the day-ahead market, ultimately makes small scale adjustments to the day-ahead market clearing in order to balance the real-time fluctuations of load demand. With this market design the uncertainty and volatility of trading in the real time market are avoided, as most of the settlement takes place at day-ahead prices. Additionally, the day-ahead clearing process and market incentives ensure a well-behaved and reliable real-time outcome.

A. The Day-Ahead Market

The day-ahead market is a financial market where the market participants submit generation offers, operating reserve offers, load demand bids, import or export transaction schedules for each hour of the following day. For increased market elasticity, the market participants can also submit virtual offers and bids that do not correspond to actual physical generation capabilities or demand needs. All offers and bids are cleared on hourly basis.

The day-ahead market clearing results are financially binding. In other words, generation resources that have cleared in the day-ahead market are financially obligated to their day-ahead schedule and known reliability requirements are enforced during the market clearing (to be discussed further in section 2.3.2), so that the cleared generation offers are operationally feasible from a transmission perspective. Additionally, the market prices reflect the true scarcity conditions in the physical system. The day-ahead market clears in a two-step process:

- Unit commitment through the Security-Constrained Unit Commitment (SCUC) algorithm
- Generation dispatch through the Security-Constrained Economic Dispatch (SCED) algorithm

B. The Real Time Market

A key objective of the real time operation is to economically dispatch generation resources to balance the constantly changing system load. Under the market structure, the task of real time economic dispatch is fulfilled through the clearing of real time market on a five minute basis.

In the real time market, market participants submit hourly real time generation and reserve offers (as separate from their day-ahead market offers) prior to each hour of operation. During the hour of operation, the market clears energy and reserve offers every 5 minutes by executing a SCED algorithm. The SCED algorithm computes the incremental output adjustments (as increased or decreased MWs) for all generation resources in the market. The net adjustment of system generation matches the system's projected demand change for the next 5 minutes. A resource's cleared generation schedule is its generation dispatch target for the next 5 minutes. At the end of an hour, the 5-minute cleared energy or reserve is integrated over the 12 periods of the hour and represents the resource's hourly cleared energy or reserve in the real time market.

The real time market operation works closely with and relies on the output of the EMS. The EMS's real time functions such as State Estimation and Contingency Analysis provide the real time market SCED engine with the generation resources' current output, network nodal sensitivities to the transmission constraints, and the monitored branch flow data. On the output side of the SCED process, the dispatch instructions resulting from the real time market clearing are sent to the market participants through the EMS SCADA function.

C. SCUC and SCED

The day-ahead and real time markets are cleared through the executions of two algorithms: SCUC and SCED. For the day-ahead market clearing, the SCUC algorithm is first run to determine which generation resources are to be committed for next day. Following the SCUC run, the SCED algorithm is then run to determine the hourly clearing quantities of energy and operating reserve from the committed generation resources, and the hourly cleared load demand from loads. For the real time market clearing, only the SCED algorithm is run to perform real-time generation dispatch and operating reserve procurement.

In either day ahead or real time market, the SCED algorithm also computes product prices as a part of its solution output.

1) General Formulations

Both SCUC and SCED are formulated as linear optimization problems such that:

$$Min\ J(x) = C^T x \tag{1}$$

Subject to: $$Ax \leq b \tag{2}$$

The objective cost $J(x)$ represents the production cost, or the societal cost for producing energy. All offered costs of energy, reserves and demand bids are embedded in the parameter vector C. And the constraints represent the operating limitations of the network equipment such as the maximum output limit of a generator, or the capacity limit of a transmission line.

For SCUC, the decision variables x include both 0/1 integer variables that represent the resource hourly commitment status, and continuous variables that represent the estimated clearing quantities of energy and operating reserves. SCUC is solved as a Mixed Integer Programming (MIP) problem. For the Midwest ISO market, the SCUC solution process involves nearly a million variables.

For SCED, since all commitment decisions are already made through SCUC, the decision variables x only represent the actual cleared quantities of energy and operating reserves. SCED is solved as a linear programming problem.

2) The Reliability Constraints

Among all the constraints of SCUC and SCED, are constraints associated with system reliability requirements. These reliability constraints ensure that energy balance, as well as whether the cleared energy can be delivered without violation of transmission security limits, and that adequate operating reserves are procured in the system through all hours of the market day.

a) Operating Reserve Constraints

There are 2 sub-categories of operating reserve in the Midwest ISO market: Regulating reserve and contingency reserve. The regulating reserve is procured and deployed by the AGC function to maintain Area Control Error (ACE), a composite indicator of the system frequency deviation from the preset value, and actual interchange deviation from its schedule. Contingency reserves are procured and deployed to replace lost generation MW during a contingency event. Contingency reserve are carried by both online and offline resources. The Midwest ISO operations require a certain percentage of the total procured contingency reserve to be carried by online resources.

At the individual resource level, for resource r at time t:

$$\begin{aligned} &EnergyMW(r,t) + RegReserveMW(r,t) + \\ &OnlineContReserve(r,t) \leq DispatchMaximum(r,t) \end{aligned} \tag{3}$$

$$\begin{aligned} &EnergyMW(r,t) - RegReserveMW(r,t) \\ &\geq DispatchMinimum(r,t) \end{aligned} \tag{4}$$

Energy MW, regulating reserve MW and online contingency reserve MW are decision variables representing market clearing quantities. The resource maximum and minimum dispatch limits are operational parameters given by the market participant's offer. It is noted that the regulating reserve carried by a resource can be deployed in both the up and down directions, whereas the online contingency reserve is deployed only in the up direction.

A resource carrying regulating reserve must have adequate ramp rate for deployment within a 5 minute period of time.

$$RegReserveMW(r,t) \leq 5 \cdot RampRate(r,t) \tag{5}$$

Likewise, a resource carrying contingency reserve must be able to deploy in 10 minutes upon notification:

$$OnlineContReserveMW(r,t) \leq 10 \cdot RampRate(r,t) \tag{6}$$

$$OfflineContReserveMW(r,t) \leq MaxOfflineLimit(r,t) \tag{7}$$

To maintain reliability, the total operating reserves procured on all qualifying resources must meet operation requirements. That is:

$$\sum_r RegReserveMW(r,t) \geq SystemRegRequirement(t) \tag{8}$$

$$\begin{aligned} &\sum_r RegReserveMW(r,t) \\ &+ \sum_r OnlineContReserveMW(r,t) * SpinAvailability(r,t) \\ &\geq SystemRegSpinReserveRequirement(t) \end{aligned} \tag{9}$$

$$\begin{aligned} &\sum_r RegReserveMW(r,t) + \sum_r OnlineContReserveMW(r,t) \\ &+ \sum_r OfflineContReserveMW(r,t) \\ &\geq SystemOperatingReserveRequirement(t) \end{aligned} \tag{10}$$

b) Transmission Security Constraints

The transmission line security constraints are formulated based on the DC load flow model. For transmission line l at time t, over all the modeled system nodes:

$$\sum_{node} Sens(node,t,l) \cdot P_{inj}(node,t) \leq Limit(l,t) \tag{11}$$

This constraint requires that the generation injections and load withdraws of the market clearing results will not induce

MW flow on a transmission line that exceeds its limit. Parameter $Sens(node,t,l)$ represents the node-branch sensitivity based on the load-center reference:

$$Sens(node,t,l) = {\partial Flow(l,t)} \Big/ {\partial P_{inj}(node,t)} \qquad (12)$$

The transmission security constraints represent either base-case (pre-contingency) or post-contingency network conditions. Together with the operating reserve constraints (8) through (10), the transmission constraints help to ensure the N-1 security of the system network during the actual energy delivery.

c) Operating Reserve Deliverability

Deployment of the operating reserves may be constrained by transmission line congestion. To ensure deliverability, operations planning divides the entire market footprint into multiple reserve zones and identifies minimum reserve requirements to enforce for each individual zone to ensure that if a contingency occurs, the contingent resource will be made up by reserves in the local zone if import restrictions exist. Constraints similar to (6) through (8) are enforced at the reserve zone level so that the cleared operating reserves are dispersed across the market footprint.

D. Market Pricing and Settlement

In an LMP market, the price of a product is set by its marginal clearing price (MCP), i.e., the increase in production cost $J(x)$ per MW increase in demand. Since energy injections at different nodal locations have different impact on the transmission congestion, the energy clearing prices are different across all network nodes and are hence called Locational Marginal Prices (LMP). The cleared operating reserves, on the other hand, do not impact congestion or loss unless deployed. The reserve prices are at most different by the reserve zones, and are called zonal MCP. Both energy LMPs and reserve MCPs can be calculated based on the constraint shadow prices of the SCED solution.

The two-market settlement system settles twice, once for the day-ahead market and once for the real-time market. For the day-ahead market, market participants settle for full clearing quantities at day ahead clearing prices (energy LMPs and reserve MCPs). For the real time market, market participants settle for the differences between their real time cleared quantities and day-ahead cleared quantities at the real time market clearing prices. (For this reason the real time market is sometimes called an imbalance market, as resources and load get cleared at their imbalance quantity with the day-ahead market.) For example, in a certain hour of the market day, a certain generator clears 100 MW of energy at \$25/MWh LMP in the day-ahead market and 90 MW of energy at \$24/MWh LMP in the real-time market. Then the generator gets paid for 100×25 = \$2500 in the day-ahead market, and pays back (100-90) ×24=\$240 in the real time market.

In the long run, the two market settlement system should lead to a convergence in prices between the day ahead and real time markets. In other words, to the extent that power system conditions were well modeled in the day-ahead market, the resource average energy clearing quantities and clearing prices should come to a close match on an hourly basis.

IV. Operations planning and Market Operation

The grid reliability is ensured through the close collaboration between operations planning and market administration. On one hand, operations planning identifies the reliability requirement parameters (operating reserve margins and security limits) to enforce for the market clearing. The market then efficiently manages transmission congestion and operating reserve procurement through clearing competitive offers, with the objective of achieving the least total production cost while respecting the parameters developed by operations planning function. Operations planning for the future system operation begins as early as a year in advance with outage scheduling and then further involves transmission security planning and reliability assessment, as the planning horizon approaches real time. Mitigation plans are developed when new system operating conditions emerge that may affect system reliability. These processes are described more fully below.

A. Outage Scheduling

In the outage coordination process, transmission and generation equipment outage requests are evaluated and scheduled for a year and beyond into the future. During the outage coordination, power flow, contingency analysis and stability studies are performed for the proposed outages. Based on the study results, the outage requests can be accepted or re-scheduled. If outages are accepted into schedule, new operating guides may need to be developed to define new transmission security limits, operating actions that must take place, and other critical contingencies associated with the outage that must be closely monitored.

The generator output schedule over the study time period is an essential input to the power flow study and contingency analysis. But for the studies of most future outages, the generation output will not become known until the day-ahead market clears on the day prior to operation. In the long-term outage studies, the generator output schedules are estimated based on the system-wide load forecast and the resource production cost merit order.

B. Transmission Security Planning

Up to a week in advance, a multi-day look-ahead security constrained unit commitment study (SCUC) is first performed. The purpose of this study is to forecast the generator output schedule for the upcoming week. The multi-day study uses the most up-to-date generator offers. It also considers the system load forecast, net scheduled interchange, the planned network outages, and major transmission security constraints. Subject to load forecast uncertainty and generator offer changes, the multi-day SCUC study provides a close estimate of generation output schedule in the upcoming week. With this estimated schedule, Transmission Security Planning (TSP) is able to conduct power flow study and contingency analysis of the grid system network over both a 3-day and 1-day future time horizon. The results of the TSP studies would include the operating reserve requirements, key transmission constraint security limits and the most limiting contingencies. These study results will be implemented in the day-ahead and real time SCUC/SCED algorithms.

C. Forward-Day Reliability Assessment and Commitment

On the day before operation, the most significant event for operations planning is the clearing of the day-ahead market. Since the day-ahead market is a financial market, there is no requirement that the demand bids (financial bids) represent the next day's load forecast. However, the Midwest ISO market design incentivizes market participants to submit demand bids that reflect their estimated needs. As a result, the total demand bids usually provide 98% of the next day's system load forecast. Therefore the generation resources cleared in the day-ahead market clearing process do meet most of the energy demand of the next day.

In order to ensure reliability, the generation schedule through the clearing of the day-ahead market must also be re-evaluated against the next day's actual load forecast and the real time market offers (which may differ from the day-ahead market offers.) Meanwhile, new transmission constraints may emerge due to the network change since the day-ahead market clearing. This re-evaluation process is conducted soon after the day-ahead market clears, in the Forward Day Reliability Assessment and Commitment (FRAC) business process. When the resources committed by the day-ahead market cannot totally meet the next day's demand forecast, FRAC will commit additional generation resources to mitigate shortage. FRAC approves its mitigation plan on the same day as the day-ahead market clearing.

D. During the Real-Time Operation

To the extent that the day-ahead market and FRAC processes accurately committed resources that satisfy real-time conditions, the day-ahead market and FRAC should have planned out a reliable generation schedule to serve the next day's energy need, and to satisfy both the adequacy and security aspects of reliability. The real time operation conducts 5-minute energy and ancillary services clearing dispatch utilizing these resources to balance the load demand, NSI, and ancillary requirements through the clearing of the real time market. The generation resource's real time dispatch quantities would be incrementally different from their day-ahead cleared positions, due to differences in real-time conditions versus those modeled in day-ahead market. On a 4-second basis, the Automatic Generation Control system (AGC) would then deploy regulating reserve to maintain system ACE.

In reality, unplanned system events always happen and create new requirements to ensure for system reliability. These unplanned conditions include:

- Forced outages such as sudden loss of generators or transmission equipments
- Significant deviation of actual load demand from forecast
- Unexpected interchange schedule changes

These unplanned events have the potential to require additional operator actions to ensure reliability. Because of these and other unplanned events, resource dispatch instructions and price signals can drive resources further away from their day-ahead clearing positions. Inside the control room, the system reliability staff work on 24-hour shifts, constantly evaluating the current operating plan against the upcoming system operating conditions. Two essential areas of responsibilities are described as follows.

Intra-Day Reliability Assessment and Commitment (IRAC): The IRAC staff constantly monitors the system operating reserve procurement with the changing load forecast for the future hours of day. New resource commitments or de-commitments will be made as necessary to respond to these changing conditions.

Reliability Coordination (RC): The RC staff performs contingency analysis on the system network based on the current as well as future operating conditions, taking into account all known outages and planned generation resource outputs. Transmission congestion identified as the day progresses result in new security constraints for the real time market's SCED engine to manage congestion as necessary. In response to these constraints, SCED will redistribute the generation output to manage this congestion. In some cases, transmission congestion relief is provided through committing new generation resources. The RC also works with neighboring RTOs and Transmission Operators to coordinate congestion management on certain transmission facilities that are impacted by the generators in both RTOs, in accordance with agreements entered into for such purposes.

Both IRAC and RC can be characterized as the intra-day, or the "near real-time" operations planning. They each address the adequacy and security aspects of the system reliability. Working together, IRAC and RC are able to handle most network events.

V. The Operations Planning Impact on Market

Under the market economic structure, system reliability is achieved through both market competition and operations planning. In the market operation, the system operating reserve is procured on qualifying resources that are cleared by the market and are paid at the marginal clearing prices for carrying reserves. Meanwhile, transmission congestion is managed through real time market dispatch and competitive pricing. Resources that help out transmission congestion are incentivized with higher LMP and vice versa for resources that cause transmission congestion. With market competition, the system reliability requirements are met for lowest production cost. The market clearing engines - SCUC and SCED, both seek to clear energy and reserve offers for the minimum objective cost while meeting all reliability constraints.

On the other hand, the efficiency of the market is dependent on how well the operations planning was performed. Poorly performed operations planning can result in expensive or ineffective mitigation strategies which will impact the market performance with high production cost and unnecessary scarcity pricing. The following discussion identifies some key aspects of operations planning that have essential influence on the market economics.

A. The Day-Ahead Operations planning

A close convergence between the day-ahead market and the real-time market, both in terms of clearing quantities and price, could help lower market operation cost. This requires that the day-ahead market clearing reflect as much of the real-time market operating conditions as possible, including accurate representation of the expected transmission topology. Successful operations planning contributes to these processes by identifying transmission constraints that will occur during the next day's operation in the absence of unplanned conditions. By incorporating these transmission constraints into its SCUC and SCED solutions, the day-ahead market clearing produces generation schedules that ensure the real-time operation a set of resources that would produce a reliable operating condition. Meanwhile, it would allow the operators to manage the power system successfully and respond to unanticipated contingencies that occur.

B. Real Time Resource Commitment

Real time market may encounter near term energy capacity shortages due to higher than forecasted load demand or unexpected NSI changes. Given the short time allowed for decision making, real time operations often require quick start resources to be committed. The commitments are made based on resource offer cost merit order. Ideally, the commitment decisions are made with the assistance of a SCUC optimization tool that considers the real time system operating conditions. However, the main challenges for development of such a commitment study tool are the complexity of the network modeling and fast solution time requirement. At times, fast changing system conditions do not allow for the time it takes to run the full optimization processes, and shorter run-time processes are used in these circumstances. Nonetheless the availability of such tools allows for economic and effective resource commitments while operating in the necessary time frame.

C. Operation Headroom

As a reliability requirement, the total online generation capacity should adequately cover the demand forecast plus online operating reserve requirement. Their difference is called the "Online Headroom". That is, at any time t during operation:

$$OnlineHeadroom(t) = OnlineCapacity(t) - EnergyDemand(t) - SystemOnlineOperatingReserveRequirement(t) \geq 0 \tag{13}$$

The online headroom can be described as the remaining online capacity after meeting energy and online operating reserve requirements. During operations planning, time t is in the future. Then the energy demand is the sum of system load forecast and net scheduled interchange at time t:

$$EnergeDemand(t) = LoadForecast(t) + NSI(t) \tag{14}$$

And the total online capacity is the sum of dispatch maximums of all generation resources r that are planned to be online at time t:

$$OnlineCapacity(t) = \sum_{r} DispatchMaximum(r, t) \tag{15}$$

As both the load forecast and NSI values are forecast estimates for the future time t, the operations planning must maintain small amounts of headroom to allow for small unpredictable changes in demand or NSI and other factors such as variations in intermittent resources output. For example, because of NSI volatility, the system energy demand can unexpectedly increase by a few hundred megawatts in less than ten minutes. Committing new resources in such short time frame is not possible. This unexpected change in demand has to be absorbed by a properly maintained online headroom cushion to avoid unnecessary operating reserve deficit and scarcity pricing.

Besides providing the necessary capacity to support expected increase in demand quantity, online headroom also enhances the ramp capability of the system generation supply. When the system experiences a steep demand change, adequate online headroom will help the system to successfully follow load.

Online headroom is one of the primary indexes for monitoring online capacity adequacy and efficiency. Although higher online headroom indicates greater reliability, it incurs more production cost. Meanwhile, the higher online headroom impacts the market economic efficiency with lower market clearing prices (LMPs and MCPs). Keeping the balance between reliability and economics by maintaining a proper level of online headroom is an ongoing challenge for the daily real time operation.

D. Renewable Resource Impact

The main impact of renewable resources on the Midwest ISO market comes from wind generation. In recent years, the Midwest ISO has seen considerable growth in wind capacity. As of today, wind generation can reach up to 7000MW at peak, which accounts for more than 5% of the footprint's load and can exceed 10% of the market load at certain times of the day and operating season. Like many other renewable energy resources, wind generation is intermittent in nature since it is critically dependent on weather conditions.

For effective operations planning involving wind generation, accurate wind forecast at the resource level is essential. It will help to determine the maximum output capability of each wind resource, assuming that the resource would be generating whenever there is wind. Operations planning can then conduct FRAC and IRAC studies to prepare for the wind impact to system capacity headroom and transmission congestion.

With the recent advances in technology, new wind turbines are being built with control features that allow variable turbine power output. In the Midwest ISO markets today, there is over 1000MW of wind generation capacity equipped with these features. These wind resources are called Dispatchable Intermittent Resources (DIR). During the market operation, DIRs are cleared and dispatched in a manner very similar to the conventional generation resources. The DIRs represent the positive technology innovations that help to mitigate the negative impact of renewable generation on the grid reliability.

VI. Conclusions

In the market economic structure, reliability requirements are valued and priced for competition. Under an appropriate market design, energy and ancillary service prices should reflect the true scarcity conditions in the system. And the market should generate correct pricing signals both to incentivize short term trading and to influence long term investment. The end goal is a market structure that provides the correct incentives to produce an efficient, reliable and secure power system outcome.

The market cannot achieve grid reliability requirement alone. It must rely on operations planning to help identify reliability requirements as inputs to the market clearing process, and to mitigate any system conditions that are not adequately provided for by the market clearing process. Effective operation planning requires coordinated studies over various time horizons that identify the necessary reliability requirements. The requirements are to be fulfilled first through the market mechanism, and then by mitigation actions outside of the market only when necessary.

VII. References

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VIII. Biographies

Mingguo Hong (S'1993, M'1998) is currently a principal market engineer at the Midwest ISO. He received his bachelor's degree in E.E. from Tsinghua University of China in 1991, master's degree in Mathematics from the University of Minnesota in 1993, and Ph.D. degree in E.E. from the University of Washington. Prior to joining the Midwest ISO, he had worked as a power systems engineer for ALSTOM T&D and also taught mathematics at Valley Forge Military College. He joined the Midwest ISO in 2006, and has been working in the Market Engineering department. His responsibilities include real time operations support, market applications testing, and market applications design. He also teaches at the ECE department of IUPUI as an adjunct faculty member.

Kimberly Sperry (S'1989, M'1992, P.E.) is currently the Director of the Market Engineering Department at the Midwest ISO. She is responsible for the engineering support of the market application systems used in the day-ahead and real-time markets. Previously she supported the energy market start-up and transmission provider start-up. Prior to Midwest ISO, Mrs. Sperry worked at Indianapolis Power & Light Company for 9 years in Distribution Planning, Transmission Planning and Control Room Support. She received her B.S in Electrical Engineering from Purdue University.

John Williams is currently the Manager of the Intra Day Reliability and Assessment (IRAC) at the Midwest ISO. He is NERC licensed to serve any responsibilities in the bulk electric system operation. Previously he had worked at the Missouri Public Service Company fulfilling various roles, including generation, protection, trading and operations management. At the Midwest ISO he oversees the IRAC team of the control room. The team works to ensure that adequate generation capacity is available to meet the MISO market real time load and operating reserve requirements at all time.

Joe Gardner is currently Executive Director, System Wide Operations for the Midwest ISO. R. Gardner is responsible for overseeing the Midwest ISO's day-to-day transmission and generation dispatch operations ensuring that the regional grid is operated in an efficient and reliable manner. Mr. Gardner joined the Midwest ISO in 2000 and oversaw the successful startup of the real time aspects of the Midwest Energy Market in 2005 as well as the startup of the Balancing Authority function commensurate with the Ancillary Services Market startup in 2009. Prior to Midwest ISO, Mr. Gardner spent 16 years in Central and South West Services (CSWS), located in Dallas, Texas, where he served most recently as Director, System Operations. Mr. Gardner has extensive operating experience in both the Electric Reliability Council of Texas and in the Southwest Power Pool and was an active participant in the committee structures of both regions. A native of Pittsburgh, PA, Mr. Gardner earned a B.S. in Electrical Engineering at the University of Texas at Arlington.