GE
Energy Consulting

PJM Renewable Integration Study

Tasks 3B & 4

Market Analysis and Mitigation

Prepared for: PJM Interconnection, LLC.

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imagination at work

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Acronyms and Nomenclatures

2% BAU	2% Renewable Penetration – Business-As-Usual Scenario
14% RPS	14% Renewable Penetration – RPS Scenario
20% LOBO	20% Renewable Penetration – Low Offshore Best Onshore Scenario
20% LODO	20% Renewable Penetration – Low Offshore Dispersed Onshore Scenario
20% HOBO	20% Renewable Penetration – High Offshore Best Onshore Scenario
20% HSBO	20% Renewable Penetration – High Solar Best Onshore Scenario
30% LOBO	30% Renewable Penetration – Low Offshore Best Onshore Scenario
30% LODO	30% Renewable Penetration – Low Offshore Dispersed Onshore Scenario
30% HOBO	30% Renewable Penetration – High Offshore Best Onshore Scenario
30% HSBO	30% Renewable Penetration – High Solar Best Onshore Scenario
AEPS	Alternative Energy Portfolio Standard
AGC	Automatic Generation Control
AWS/AWST	AWS Truepower
Bbl.	Barrel
BAA	Balancing Area Authority
BAU	Business as Usual
BTU	British Thermal Unit
CA	Intertek AIM's Cycling⬍Advisor ™ tool
CAISO	California Independent System Operator
CC/CCGT	Combined Cycle Gas Turbine
CEMS	Continuous Emissions Monitoring Systems
CF	Capacity Factor
CO2	Carbon Dioxide
CV	Capacity Value
DA	Day-Ahead
DR	Demand Response
DSM	Demand Side Management
EI	Eastern Interconnection

EIPC	Eastern Interconnection Planning Collaborative
ELCC	Effective Load Carrying Capability
ERCOT	Electricity Reliability Council of Texas
EST	Eastern Standard Time
EUE	Expected Un-served Energy
EWITS	Eastern Wind Integration and Transmission Study
FERC	Federal Energy Regulatory Commission
FLHR	Full Load Heat Rate
FSA	PJM Facilities Study Agreement
GE	General Electric International, Inc. / GE Energy Consulting
GE MAPS	GE's "Multi Area Production Simulation" model
GE MARS	GE's "Multi Area Reliability Simulation" model
GT	Gas Turbine
GW	Gigawatt
GWh	Gigawatt Hour
HA	Hour Ahead
HSBO	High Solar Best Onshore Scenarios
HOBO	High Offshore Best Onshore Scenarios
HR	Heat Rate
HVAC	Heating, Ventilation, and Air Conditioning
IPP	Independent Power Producers
IRP	Integrated Resource Planning
ISA	PJM Interconnection Service Agreement
ISO-NE	Independent System Operator of New England
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
lbs	Pounds (British Imperial Mass Unit)
LDC	Load Duration Curve

LM	Intertek AIM's Loads Model ™ tool
LMP	Locational Marginal Prices
LNR	Load Net of Renewable Energy
LOBO	Low Offshore Best Onshore Scenarios
LODO	Low Offshore Dispersed Onshore Scenarios
LOLE	Loss of Load Expectation
MAE	Mean-Absolute Error
MAPP	Mid-Atlantic Power Pathway
MMBtu	Millions of BTU
MVA	Megavolt Ampere
MW	Megawatts
MWh	Megawatt Hour
NERC	North American Electric Reliability Corporation
NOx	Nitrogen Oxides
NREL	National Renewable Energy Laboratory
NWP	"Numerical Weather Prediction" model
O&M	Operational & Maintenance
PATH	Potomac Appalachian Transmission Highline
PJM	PJM Interconnection, LLC.
PPA	Power Purchase Agreement
PRIS	PJM Renewable Integration Study
PRISM	Probabilistic Reliability Index Study Model
PROBE	"Portfolio Ownership & Bid Evaluation Model" of PowerGEM
PSH	Pumped Storage Hydro
PV	Photovoltaic
REC	Renewable Energy Credit
Rest of EI	Rest of Eastern Interconnection
RPS	Renewable Portfolio Standard
RT	Real Time

RTEP	Regional Transmission Expansion Plan
SC/SCGT	Simple Cycle Gas Turbine
SCUC/EC	Security Constrained Unit Commitment / Economic Dispatch
SOx	Sulfur Oxides
ST	Steam Turbine
TARA	"Transmission Adequacy and Reliability Assessment" software of PowerGEM
UCT	Coordinated Universal Time
VOC	Variable Operating Cost
WI	Western Interconnection

1 Task 3b: Market Analysis

1.1 Market Analysis Tasks

This task covered the analyses performed by the GE team to identify the market impacts for the scenarios developed in Task 2, based on modeling results of Task 3a.

The purpose of this task was to quantify the market impacts under the different scenarios and suggest improvements to market products and procedures that will facilitate high penetration of renewable generation in PJM.

The results from the GE MAPS and PROBE simulations were used to determine the impact of wind and solar generation on the PJM markets under the scenarios developed in Task 2. The annual GE MAPS simulation produced hourly dispatch of generators, their emissions, hourly flows on transmission lines and shadow price if congested and hourly system bid production cost. The report section on Task 3a consolidated the hourly GE MAPS simulation results to obtain the market-related information that PJM is interested in, such as, annual bid production cost, average LMP, annual congestion cost and annual emissions. The sub-hourly PROBE simulation determined the impact of renewables on the imbalance market, with particular focus on quick start capacity committed in the RT dispatch.

This section of the report on Task 3b presents additional analysis and findings relevant to the PJM market, including recommended improvements to the market products and procedures in view of higher penetration of renewable resources.

The following improvements to market products and procedures were investigated.

1.1.1 Study Methods for Determining Operational Reserve Requirements

In Task 3a, through statistical analysis it was possible to calculate the amount of additional regulation reserves that would be needed within the PJM operating area as a function of the aggregate wind and solar power output. In Task 3b, using the findings from Task 3a on operating reserve requirements, the theory is translated into a step-wise practical approach for incorporating that methodology into day-ahead and real time operations of the PJM system.

1.1.2 Dealing with Uncertainties in the Real Time Market

This task considered uncertainties in the load and renewable resource availability, which were modelled by modified load forecast and unit availability between DA and RT runs. For this task, a number of sub-hourly PROBE simulations were performed for selected days to study the impact of better and shorter term renewable forecasts and unit commitment, which included the following sub-hourly sensitivity simulations over previously considered selected challenging days:

- 4-Hour-Ahead Wind and Solar Forecast & Unit Commitment
- Perfect Wind and Solar Day-Ahead Forecast
- Reduced Wind and Solar Forecast Error

A sensitivity considering Low Natural Gas Price and High Carbon Prices was also considered, in order to evaluate the impact on short-term operations.

1.1.3 Best Practices from other markets

Another sub-task of Task 3b was to provide an overview of best practices from other markets by review of the industry and academic literature, focusing on several well-known variable energy integration issues. This task was completed in the early stages of this study and the following separate final report on the topic was issued:

PJM Renewable Integration Study, "Task Report: Review of Industry Practice and Experience in the Integration of Wind and Solar Generation", Prepared by: Exeter Associates, Inc. and GE Energy, November 2012.

1.2 Methods for Determining Regulation Reserve Requirements

1.2.1 Introduction

The variability and uncertainty of renewable energy production has a definite impact on the amounts of regulation and operating reserves required to maintain adequate control performance as illustrated by the analysis in previous tasks.

Also as noted in the report section on Task 3a Reserve Analysis, in this study contingency reserves consists of at no less than the largest contingency where synchronized reserves consist of at least 50% of on-line generation and customer demand response can be no more than 25%[1]. Although variability and uncertainty exists for wind and solar resources, the generating capability of any single renewable plant modeled in the study is less than the largest single generating contingency on the PJM system. For this reason the existing contingency reserves established for PJM were not changed when modeling reserves within the GE MAPS program. It is the very short intermittency of wind and solar generation variability that presents the challenge to operation modeling.

[1] PJM Manual 10: Pre-Scheduling Operations, Revision: 27, Effective Date: February 28, 2013; and "Reserves – Scheduling, Reporting, and Loading presentation", PJM State & Member Training Department Operations 101, June 18, 2013.

The analysis conducted to analyze reserve impacts took advantage of the fact that, for each scenario, the aggregate renewable production was known in advance. The behavior of wind and solar PV generation in each scenario, therefore, could be analyzed both separately and in comparison to PJM load, and statistically characterized prior to performing chronological production simulations. In reality, as renewable production in PJM increases, this type of analysis would have to be done "on the fly" as renewable production data is archived over time.

1.2.2 PJM Existing Regulation Reserve Requirement and Procurement Processes

The traditional PJM practice for determining regulation requirements was based on a day-ahead forecast of hourly load. Required regulation capacity was defined to be 1% of the projected next-day peak hourly demand for 18 hours (5:00 am to 12:00 midnight), and 1% of the valley load for the overnight hours (midnight to 5:00 am).

On October 1, 2012, PJM implemented new market rules to compensate better performing regulation resources (such as storage) in compliance with FERC Order 755. Part of the rationale for this change was based on a comprehensive study of PJM regulation requirements and performance. In this evaluation, detailed simulations of AGC, regulating unit response, and frequency control performance were conducted to better understand: 1) the value of faster and more accurate response of regulating units for maintaining target control performance, and 2) the amount of total regulation capacity that is really required to maintain adequate control as indicated by the NERC CPS1 metric.

A further change in the regulation practice was approved by PJM members on August 1, 2013 and implemented on December 1, 2013. Rather than a defined fraction of forecast loads, PJM now carries 700 MW of effective regulation capacity for all on-peak hours (5:00 am to 11:59 pm) and 525 of effective MW over the off-peak hours (12:00 midnight to 04:59 am).

In the daily procurement process, regulation offers are received by 6:00 pm prior to the operating day, with provisions for adjustments in the operating day up to 60 minutes prior to the operating hour. The regulation market is cleared hourly.

1.2.3 Review of Operating Reserve Assessment for This Study

The general approach taken in this study for analyzing the effects of renewable generation on PJM regulating and operating reserve requirements is depicted in Figure 1-1. It should be noted that the analysis conducted for this study utilized the traditional regulation practice rather than the policy currently in effect, as this part of the study preceded the approval and implementation of the changes.

For each scenario of wind and PV generation, the aggregate 10-minute production profile over the three years of synthetic data is characterized. From this analysis, expectations of variability and/or uncertainty over real-time operating horizons are quantified. The aggregate renewable profile is combined with PJM load data, and the variability of net load is examined. Using data and other information from the current PJM practice for determining regulation requirements, a new formulation is constructed to account for increased variability of net load. The state- and weather- (sky cover) dependent variability of renewable generation is accounted for, which results an 8760 hour profile of regulation capacity. The profile is then passed to the production simulation as an increment to the spinning reserve constraint to be honored during commitment and economic dispatch.

Results of the production simulations are then analyzed to assess possible impacts on operating reserves. This is done by examining the hourly "flexibility" - the available aggregate capacity range and ramp rate – over and above what is designated as contingency reserve. If deficiencies are noted during periods of high renewable generation volatility (especially in the downward direction), an increase in operating reserve requirements may be warranted.

Using this process, this study developed curves of regulating reserve requirements for the PJM operating area as a function of aggregated wind and solar power production.

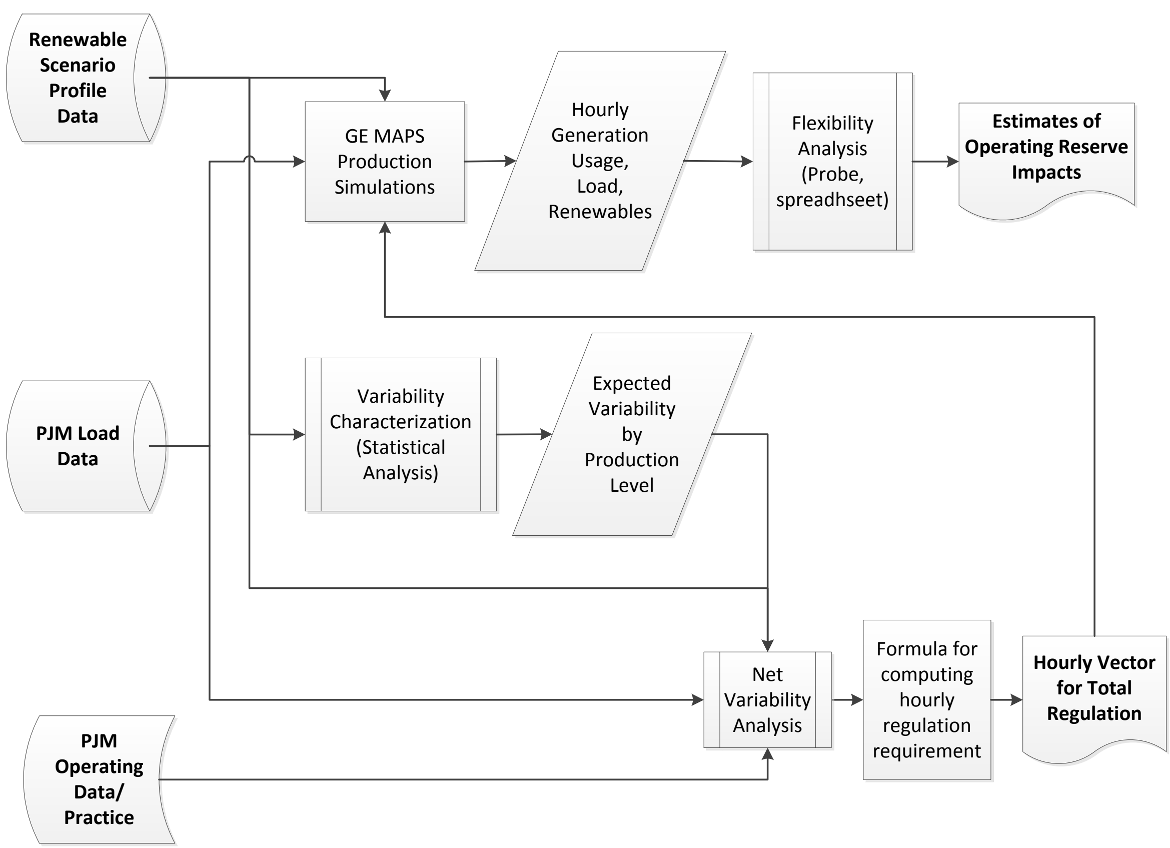

Figure 1-1: Procedure Utilized In Study for Analyzing Renewable Generation Impacts on Regulation and Operating Reserve

1.2.4 Hypothetical Approach for Implementation in PJM Operations

The approach used in the study could be adapted to provide a framework for evolving PJM's operational practice as the penetration of renewable generation grows. In fact, the approach roughly mimics an operational scenario, with the unit commitment step a proxy for short-term operational planning and the economic dispatch phase of the production simulations representing real-time operation. The aforementioned reserve vector derived from the statistical analysis approximates a process where reserve requirements are determined on the basis of load forecasts and short-term forecasts of renewable generation.

1.2.4.1 Assessing Requirements

In this study, as is the case in all previous integration studies, the analysis of reserve impacts is limited by:

- The resolution of the renewable resource and load profile data. The synthetic renewable data is available at 10-minute intervals.
- The lack of a historical record in terms of system operations.
- The substantial change to the system operating profile due to significant renewable penetration.
- The lack of historical record regarding system control performance.
- A necessarily simplified treatment of operational detail and overarching market mechanisms.
- The resolution of the chronological production simulations. Because of the 1-hour time steps, regulation and load-following requirements are considered only as constraints on the commitment and dispatch, and provides no evaluation of whether the quantities allocated for these activities are adequate.

As renewable generation is deployed, the energy management infrastructure supporting grid operations at PJM provides a platform for refining the approximations utilized in the study for assessing reserve impacts. Figure 1-2 illustrates how this infrastructure could be leveraged to substantially improve on the study approach and lead to actionable information for system operations.

There are three general categories of information that would likely be available from archive records. These include:

- Renewable production data, consisting of high temporal resolution profile data for individual generators (except for distributed resources), along with forecasts and possibly some meteorological data.

- Load and generation, again at high temporal resolution, but individual unit and delivery point.
- System performance data, including control performance metrics (CPS1 and BAAL) with reserve allocation and deployment and information about operating reserve deployment or violations.

Against this historical backdrop, a variety of analyses could be conducted periodically to adjust operating rules and policies. The frequency of such reviews will depend on the renewable penetration as well as the rate of change in renewable penetration.

Some obvious assessments would include:

- Statistical variability of renewable generators, individually, by reserve zone or region, or in the aggregate, for different production levels, seasons, etc.
- Control performance as a function of renewable generation levels, to identify any correlation that would be indicative of insufficient regulation or other operating reserves
- Available generation flexibility during periods of high renewable energy fluctuations that would indicate whether operating reserve policies need to be re-evaluated.
- Modifications to energy management system functions, such as short-term load forecasting that would better account for changes in renewable generation over economic dispatch cycles. Integration of improved short-term renewable generation and ramping forecasts are examples.

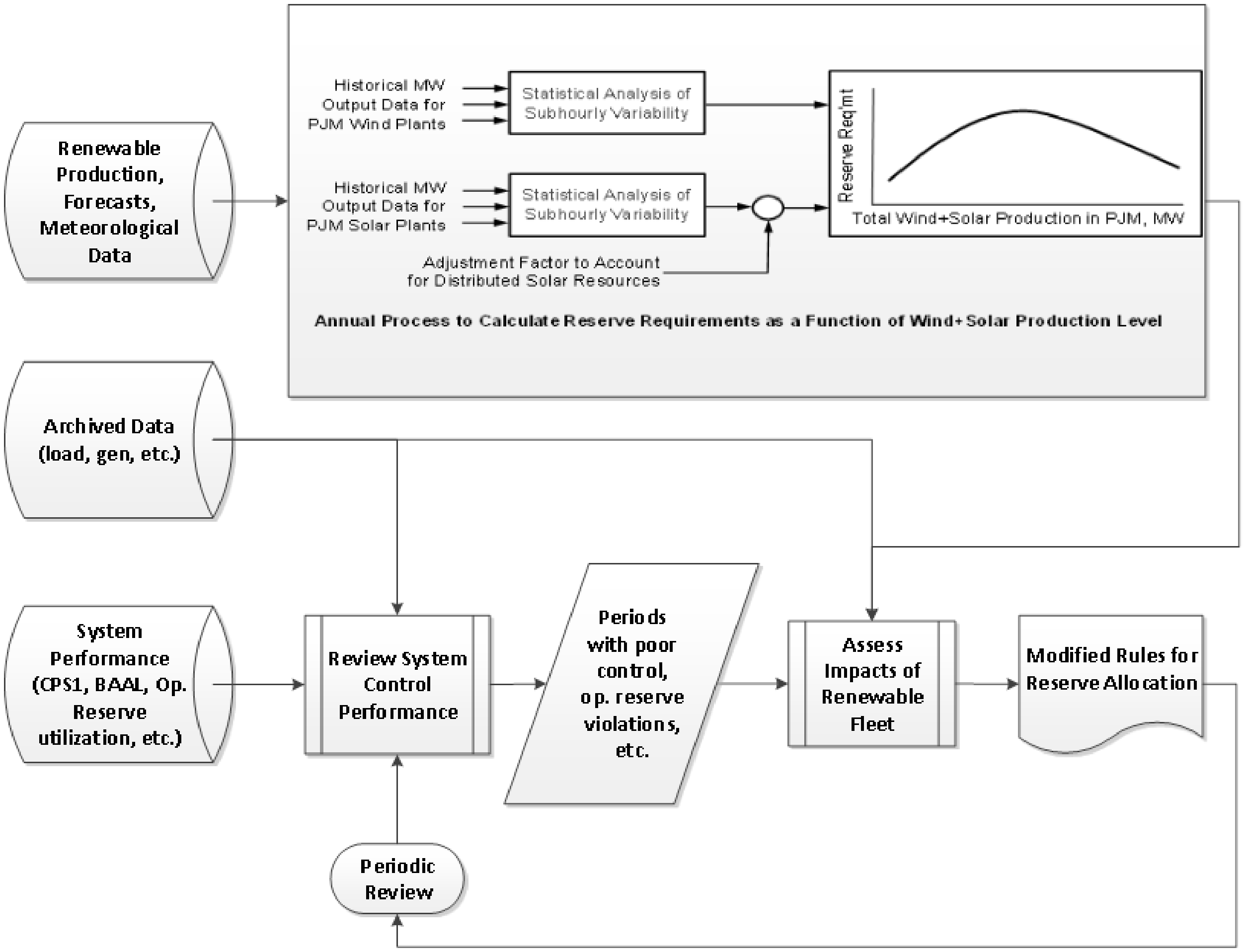

Figure 1-2: Adaptation of Study Approach for Reserve Analysis into Operations Planning

As renewable generation has become a substantial fraction of the capacity in some U.S. balancing authority areas (BAAs), system operators have already taken steps like those described above to improve their ability to integrate renewable generation economically and reliably. In many ways, what is underway in these BAAs differs little from the longstanding approach taken by system operators to utilize what they have observed and experienced to better prepare them for the future. The only significant difference here is to factor in the variability and uncertainty of wind and solar resources in a mathematically rigorous and technically reasonable manner.

The report on the "best practices" task of this study[2] provides information on how CAISO, ERCOT, and several other regions are addressing reserve requirements as a function of wind and/or solar generation in daily operations.

1.2.4.2 Procuring Reserves

Results of this study show that the degree to which operating reserve requirements are affected by renewable generation depends on the actual state of the renewable generation – when there is no renewable production; no additional operating reserves are needed. Taking this a bit further, the statistical analysis from the previous task also shows that when renewable production is low, the effects are small, grow with increasing production, and "tail off" somewhat as maximum production is approached (Figure 1-3 to Figure 1-5).

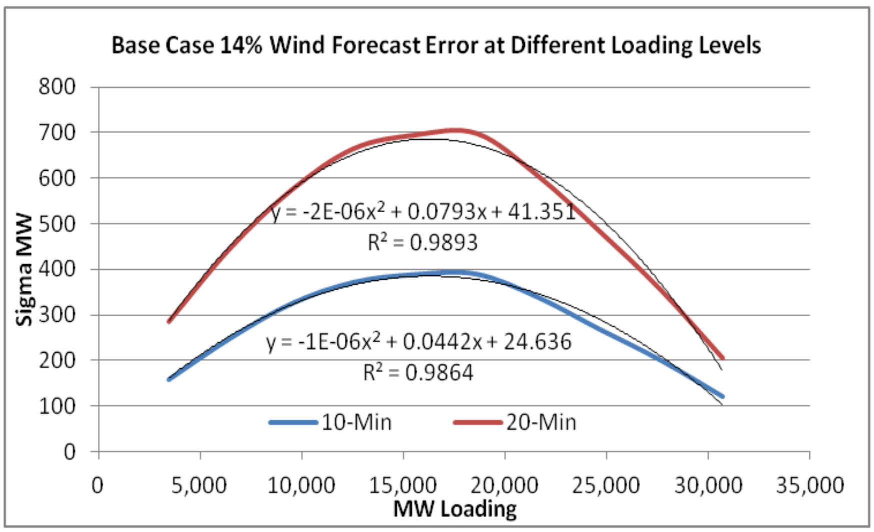

Figure 1-3: Statistical Characterization of Wind Production for the 14% RPS Scenario

[2] PJM Renewable Integration Study, "Task Report: Review of Industry Practice and Experience in the Integration of Wind and Solar Generation", Prepared by: Exeter Associates, Inc. and GE Energy, November 2012.

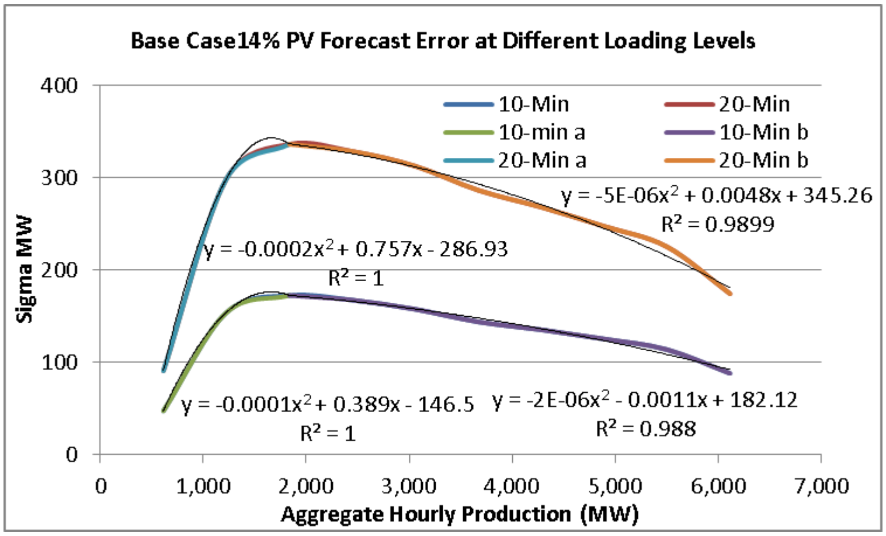

Figure 1-4: Statistical Characterization of Solar PV Production for the 14% RPS Scenario

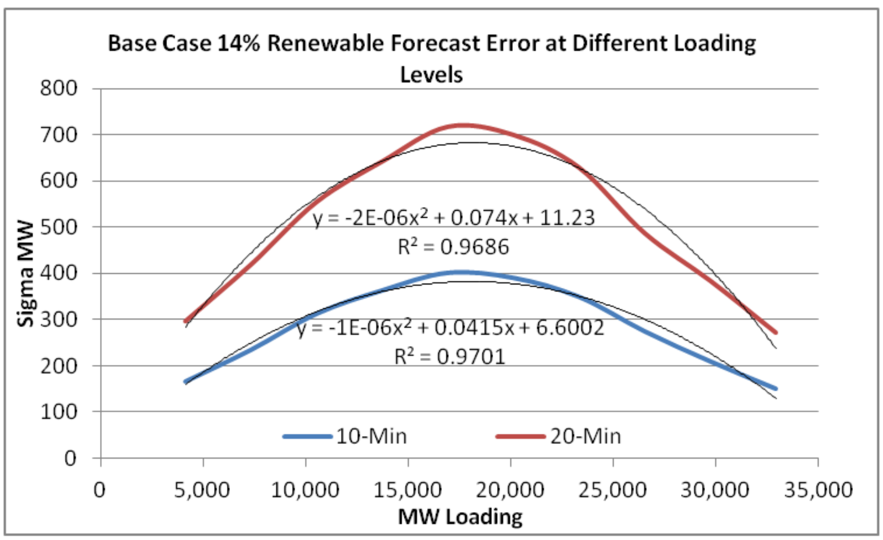

Figure 1-5: Statistical Characterization of Aggregate Renewable Production for the 14% RPS Scenario

These characteristics are very similar to what has been observed for aggregate wind generation production profiles in nearly all previous large-scale wind integration studies. The addition of significant solar PV to the scenario changes the characteristic somewhat in that daytime and nighttime hours would exhibit different characteristics with such a mix.

This potentially poses some challenges for procurement of reserves, as the requirement becomes much more dynamic. And, since the procurement must happen in advance of the need, decisions will necessarily be based on forecasts. The nature of renewable generation forecasting would dictate that these decisions be made as close as possible to the time of actual need. However, the time constants associated with market mechanisms do require some lead time.

PJM currently bases regulation requirements on next-day forecasts of peak and valley loads, so the structure already in place has the basic attributes. Day-Ahead hour-by-hour forecasts of renewable generation, however, especially for wind, may have significant error, and could lead to significant over- or under-procurement. Renewable forecasts for one to a few hours ahead would be much more accurate, but would likely require changes to the function of the regulation market.

An approach for leveraging more accurate short-term renewable forecast information is suggested in Figure 1-6. Such short-term, nearer-to-real time adjustments could potentially be similar in mechanics to the current adjustments made in the PJM regulation market.

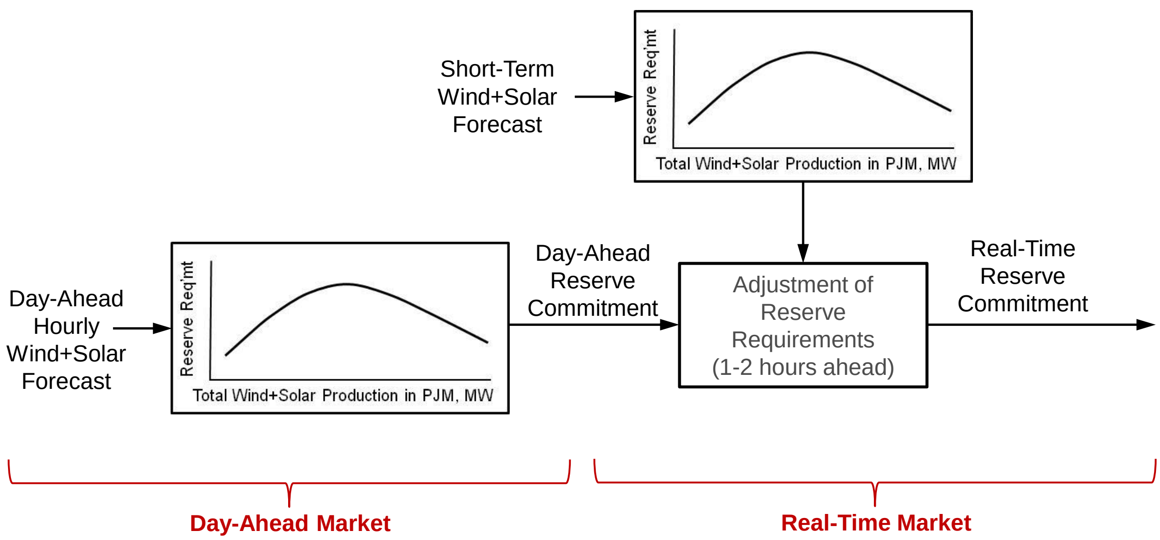

Figure 1-6: Possible Daily Process for Calculating Reserves Required for Real-Time Operations

The process suggested here also has applicability to other operating reserves. While the study findings do not indicate that the renewable scenarios considered would be cause for changing existing contingency reserve policies, it is possible that the actual increase in renewable penetration over time could pose some challenges on a regional basis. The value of such a process is that periodic analysis of archived renewable production data would allow changes to operating reserve policies to be considered prior to their actual need. Monitoring of system flexibility over time, especially during significant renewable production changes, would form a solid basis for policy revisions.

Finally, there is a growing trend in wholesale energy market design to allow renewable generation to participate as broadly as possible. With respect to certain ancillary services, such as primary frequency response, there have been technological developments implemented by wind turbine vendors over the past several years that open up the possibility for wind plants to potentially provide this service. There have also been moves to integrate renewable plants much more tightly with grid operations up to the point of interacting via AGC (automatic generation control). With regard to regulation, bifurcation of the overall regulation requirement into an "UP" and "DOWN" component, along with AGC, would allow renewable plants to provide regulation in times of scarcity/high prices.

1.2.5 Summary: Recommendation for Dynamic Determination of Reserves

As noted in the Reserve Analysis section, the additional regulation reserves required were relatively small compared to the amount of renewable generation added. The 30% Scenarios, which added over 100,000 MW of renewable capacity, required only 1,000 to 2,000 MW of additional regulating reserves compared to the roughly 2,000 MW of regulating reserves modeled for load alone. The key recommendation is that these reserves should be dynamically determined based on the next day's forecast for wind and solar generation.

1.3 Analyzing Market Uncertainties

For the following two tasks:

- Dealing With Uncertainties In The Real Time Market
- Energy And Ancillary Services Co-optimization In DA Market

It was agreed that the following sub-hourly sensitivities to be performed on previously selected challenging days and scenario combinations in order to study the uncertainties in the real time market and the impact of short-term forecast and security constrained unit commitment:

- 14% RPS, May 26: 4-Hour Ahead Wind and Solar Forecast
- 14% RPS, May 26: Perfect Wind and Solar Day-Ahead Forecast
- 20% LOBO, February 17: Reduced Wind/Solar Forecast Error
- 14% RPS, February 17: Low Natural Gas Price, High Carbon Price
- 30% LOBO, February 17: Low Natural Gas Price, High Carbon Price

1.3.1 Summary of Results: Sub-Hourly Sensitivities

Table 1 summarizes high-level results of the sub-hourly simulations for the sensitivity cases.

Table 1-1: PROBE Analysis Results Summary for Sensitivity Simulations

	14%, 5/26, 4-HR Forecast	14%, 2/17, HC, LG	14%, 5/26, Perfect Forecast	20% LOBO, 2/17, Low Error	30% LOBO, 2/17, HC, LG	30% LODO, 6/18, High Ramp Rate
Instances of Load Shedding	0	0	0	0	0	0
Intervals When Reserves provide Energy	0	2	0	0	0	0
Average Dispatch Headroom - Online Steam/CC (MW)	7566	2530	8413	6429	6099	9154
Minimum Dispatch Headroom - Online Steam/CC (MW)	53	0	0	57	0	338
Instances of Ramp-Constrained Generation	3819	1295	3957	3001	2474	2147
Total Unit-Intervals of RT CT Commitment	371	489	171	309	792	727
Average RT CT Commitment per Interval	2.5	3.5	1	2	5	5
Number of RT CTs Committed - Highest Interval	16	30	7	11	25	19
Average LMP	$79.47	$77.88	$71.45	$60.05	$74.96	$63.67
LMP Spikes	2	2	1	3	2	2
Average Reserve Price	$24.60	$29.45	$22.50	$12.18	$23.70	$9.64

The results of these simulations varied as the objective of each simulation was different. Each of the simulations is discussed in more detail below and, where possible, the results of the sensitivities are measured against the results of comparable simulations from Task 3a.

1.3.2 4-Hour-Ahead Wind and Solar Forecast

<u>Selected Scenario/Day: 14% RPS - May 26</u>

This sensitivity considers impact of less uncertainty with a 4-hour forecast of wind and solar and unit commitment.

The following observations are made on the simulation results:

- Low headroom during several intervals
- Large number of ramp constraints; quick change between generators ramping down and then ramping back up
- Significantly less CT commitment in real-time than the baseline 14% RPS simulation for this day

This day is largely defined by a sharp increase in on-shore wind just after midnight, followed by a sharp decrease in the early morning, with another clear increase in the afternoon, as shown in Figure 1-7.

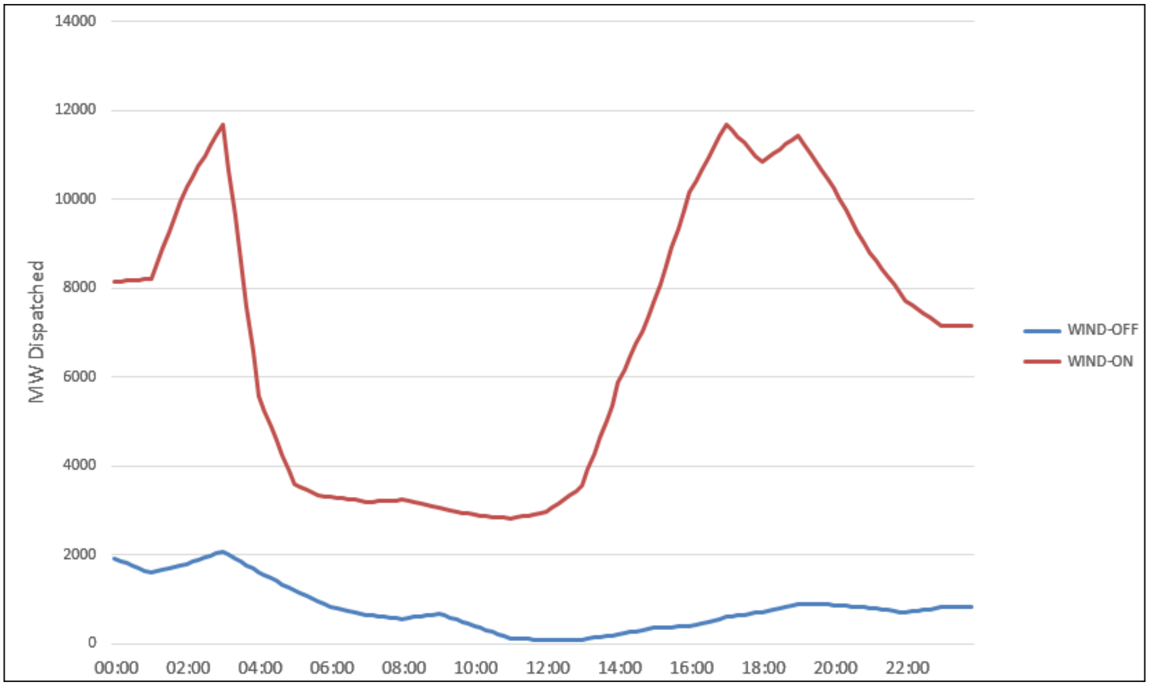

Figure 1-7: Wind Generation Output (14% RPS - May 26)

The combination of wind increase beginning around 1 AM combined with decreasing demand shows a high persistence of downward ramp constraints; this is the same result for the 4-hour forecast simulation as for the baseline simulation. In Figure 1-8 ramp constraint instances are separated into downward and upward.

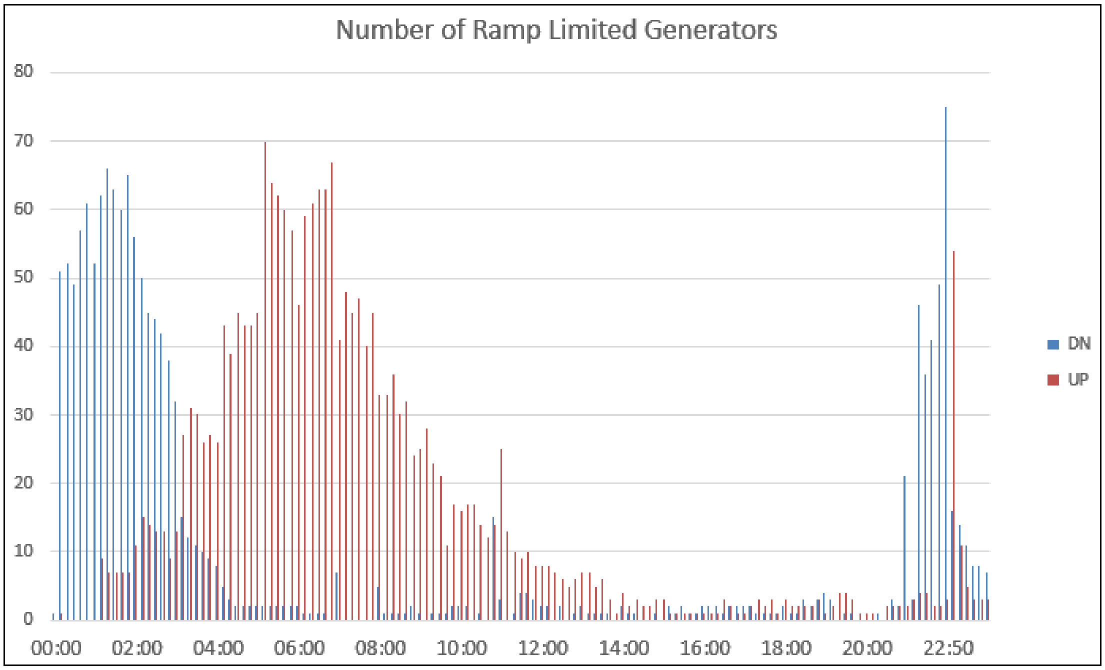

Figure 1-8: Number of Ramp-constrained Units per 10-minute Interval (14% RPS - May 26)

Clearly, thermal generation is ramped down only to be ramped up again shortly afterwards as the wind output drops significantly and load begins to increase. It is also interesting to note that during the afternoon hours, the increased wind generation follows load increase, and in this case reduces the ramp constraints on thermal generation as they are not as active in following load. Again, this is almost identical to the baseline May 26 results.

The main difference noted in this sub-hourly simulation as compared to the baseline is the reduction in real-time CT commitment, as measured both by number of CTs and MW dispatched from CTs. Figure 1-9 shows the CT dispatch per interval between the original and 4-hour forecast simulations.

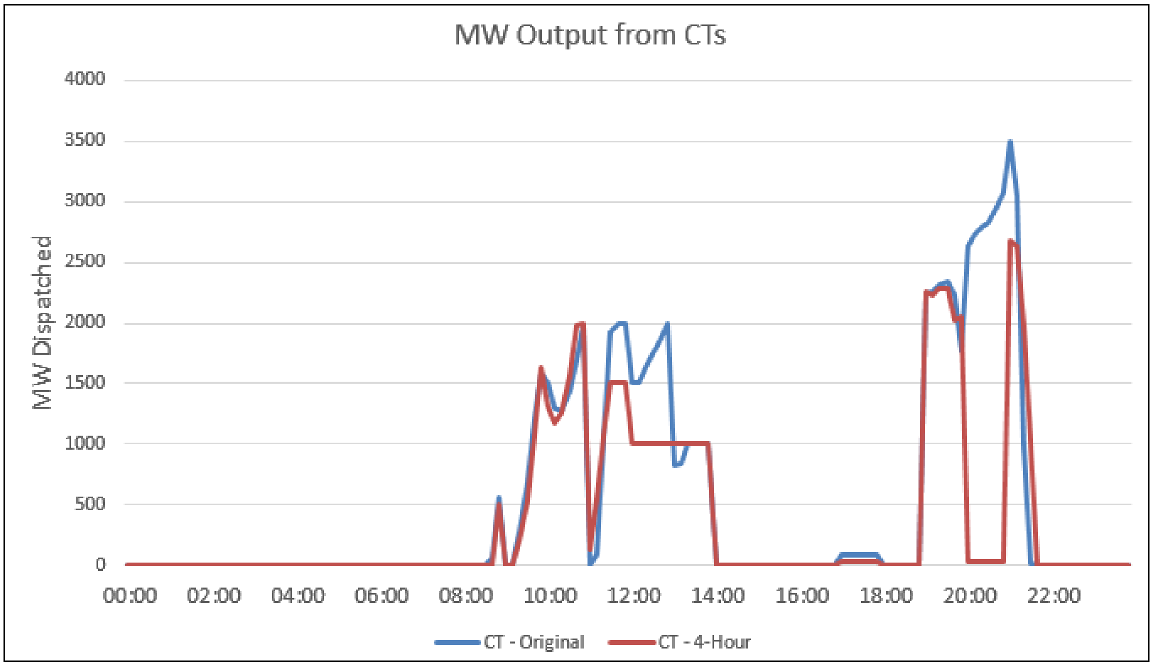

Figure 1-9: CT Dispatch by Interval (14% RPS - May 26)

1.3.3 Perfect Wind and Solar Forecast

<u>Selected Scenario/Day: 14% RPS – May 26</u>

This sensitivity considers impact of no uncertainty with perfect forecast of wind and solar.

The following observations are made on the simulation results:

- Higher average headroom as compared to the 14% RPS baseline and 14% RPS 4-hour forecast simulations for the same day
- Continued lower CT commitment than the 14% RPS 4-hour forecast simulation for the same day (which already was lower than the baseline)
- Additional benefits observed are lower LMPs and fewer transmission constraints compared to the other 14% RPS, May 26 studies
- Still a high number of ramp constraints; quick change between generators ramping down and then ramping back up

Using the “perfect forecast” for May 26 provided additional benefits as compared to the other 14% RPS studies for the same day. In fact, this day solved with no operational challenges other than the ramp constraints, which were similar to the other May 26 simulations. Given the significant, rapid change in renewable energy in all May 26 studies, ramp limitations are expected.

Figure 1-10 shows the CT dispatch per interval for all three May 26, 14% RPS simulations. With the exception of a few intervals, this simulation showed the fewest CTs committed and fewest MW dispatched from CTs.

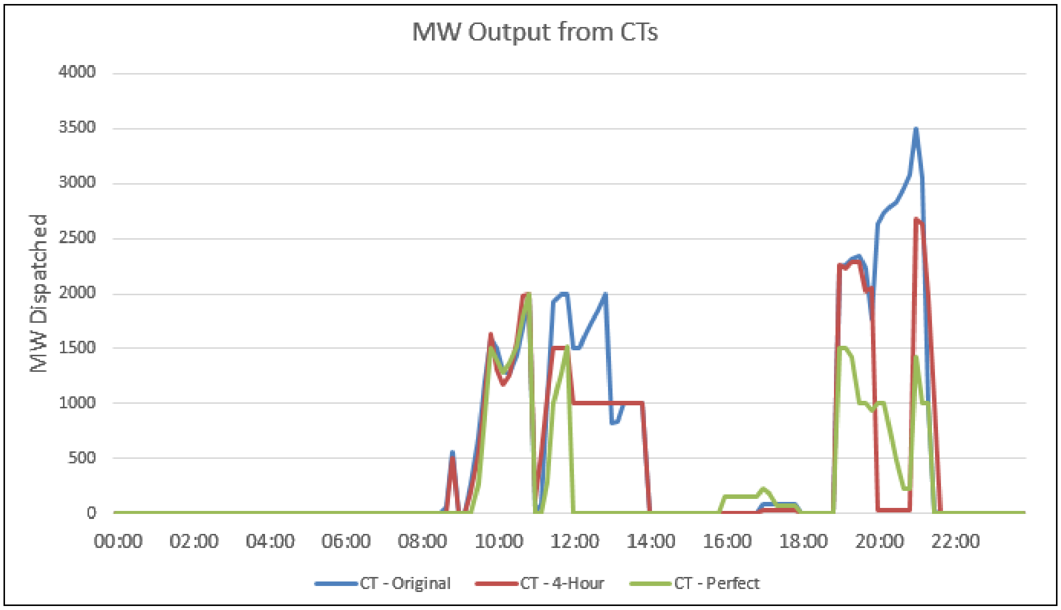

Figure 1-10: CT Dispatch by Interval (14% RPS - May 26)

Figure 1-11 shows the LMP comparison between May 26, 14% RPS sub-hourly simulations. Note that the "perfect forecast" simulation has a lower LMP in nearly all intervals.

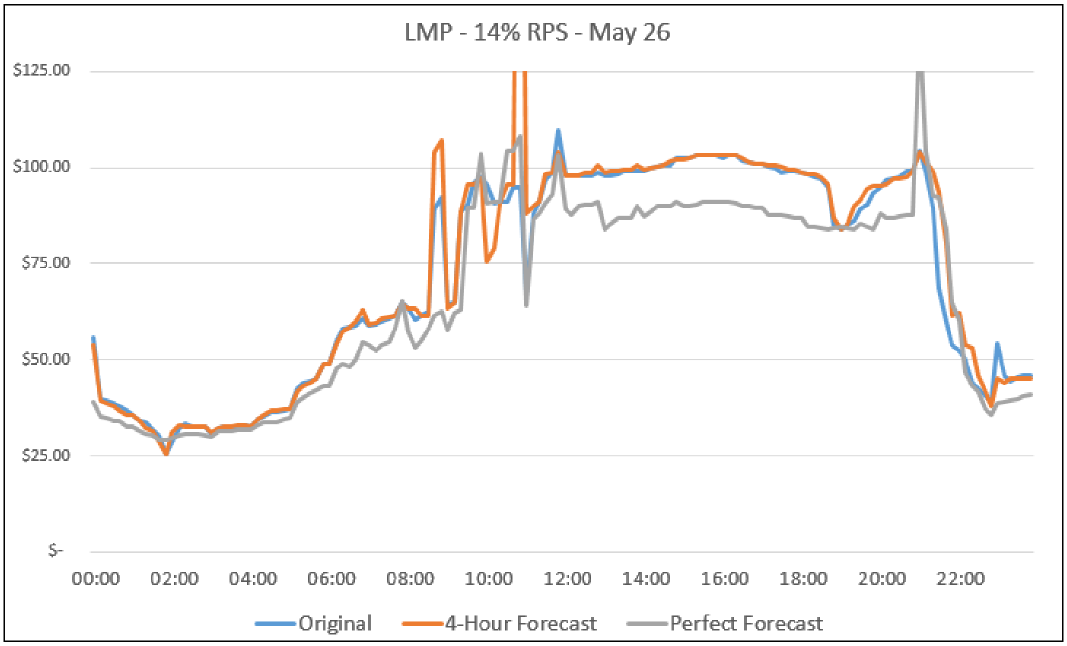

Figure 1-11: LMP Comparison for Sensitivities (14% RPS - May 26)

1.3.4 Reduced Wind and Solar Forecast Error

Selected Scenario/Day: 20% LOBO – February 17

This sensitivity provided another look at lowering the uncertainty, by considering impact of reduced wind and solar forecast error (the forecast / actual differentials were reduced by 20%).

The following observations are made on the simulation results:

- Several intervals with near-zero headroom
- Overall, a significant improvement as compared to the corresponding sub-hourly analysis for February 17 in the baseline 20% LOBO case
- Some real-time CT commitment, but less than other February 17 simulations

This simulation was an improvement as compared to the corresponding sub-hourly simulation for the baseline case, and in fact an improvement compared to most sub-hourly simulations for February 17. The improvement can be largely attributed to a better forward commitment resulting in higher average headroom.

Figure 1-12 shows a comparison of headroom between cases, and Figure 1-13 shows the LMP comparison.

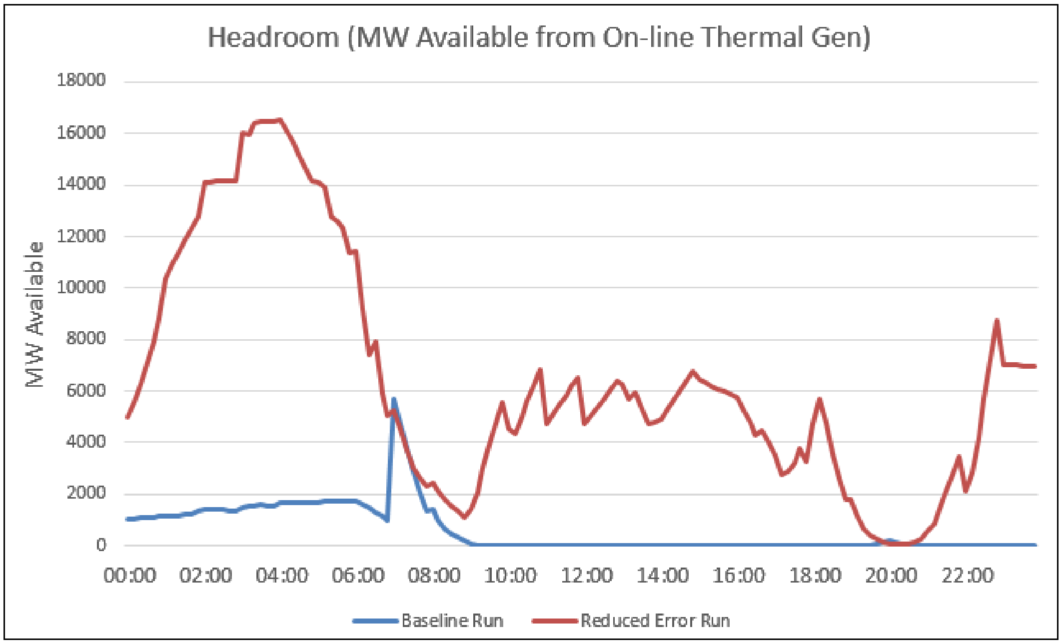

Figure 1-12: Headroom - MW Available from Thermal Generation (20% LOBO - February 17)

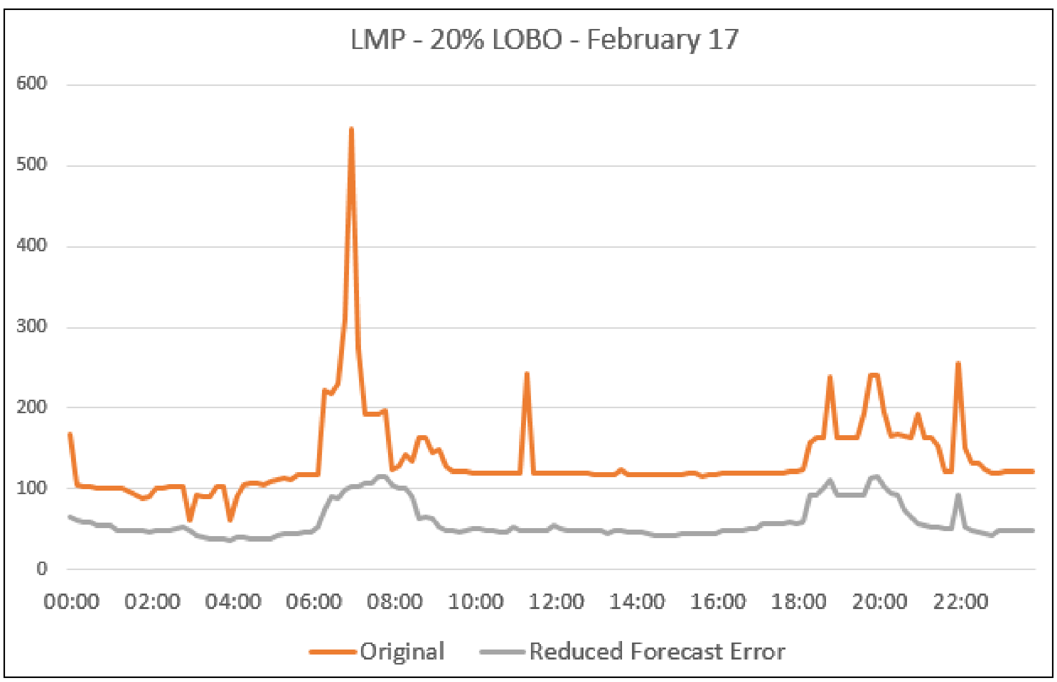

Figure 1-13: LMP Comparison for Sensitivities (20% LOBO - February 17)

Regardless of level of improvement, there were still some operationally challenging intervals with generator ramp limitations, low headroom, and CT commitment. However, no significant violations were observed.

It should be noted that in Figure 1-12 the zero headroom on the y-axis already accounts for, and includes, the regulation reserve. The headroom is the amount of thermal capacity available over and beyond the allocated reserve. Hence, at zero headroom, the reserve is still available. When the headroom goes negative, then the reserve will be called in. In actual operations, unless there are transmission or ramping constraints, CTs would not be committed real time to serve energy unless the headroom on existing committed units was depleted.

Another important point to keep in mind is that the sub-hourly analysis in PROBE used the internal PJM data on thermal plant ramp rates, in contrast to the hourly GE MAPS analysis which used a general 2% ramp rate agreed upon with PJM at the beginning of the study. Some of the additional issues highlighted in the sub-hourly analysis are results of this discrepancy between GE MAPS and PROBE ramp rate assumptions. To further evaluate the impact of this discrepancy in assumptions, a sensitivity analysis was performed using the 2% ramp rate in the PROBE modeling, which eliminated most of the challenging situations reported in the PROBE analysis under Task 3b. In other words, if GE MAPS simulation had used the same PROBE PJM based ramp rates (instead of the 2% ramp rates that was agreed upon at the beginning of the study by PJM), then the consignment of reserve capabilities to plants would have been somewhat different, and GE MAPS would likely have allocated reserve differently in the day-ahead unit commitment and hour-ahead economic dispatch, resulting in less challenging situations during the sub-hourly dispatch experienced in the PROBE simulation.

1.3.5 Low Natural Gas Price and High Carbon Price

<u>Selected Scenario/Day: 14% RPS – February 17</u>

This sensitivity considered the case of lower natural gas prices with higher (non-zero) carbon price at sub-hourly level for the 14% RPS scenario.

The following observations are made on the simulation results:

- Low headroom on average and several sub-hourly intervals with zero headroom
- Reserves required to cover energy shortage during two intervals
- Results are not significantly different than the original 14% RPS simulation

The results between this February 17 sub-hourly simulation and the same day under the 14% RPS baseline are similar. As noted in that section, overall, February 17 at the 14% renewable level solves with relative ease, but the low headroom at the 14% level proves to be a consistent trend for February 17 in other scenarios with higher penetration levels.

The main difference between this and the original February 17 is that there is less average headroom and higher average LMPs, despite real-time CT commitment remaining the same. Two intervals experienced situations where reserves were used to provide energy (versus none in the original), though the level of violation was minimal.

Another difference, and likely the reason for the lower headroom, is that fewer large steam turbines were committed in this case than in the original. This is a reasonable expectation under a high-carbon price scenario as coal plants will be more expensive.

Results: 30% LOBO – February 17: High Carbon Price, Low Gas Price

This sensitivity considered the case of lower natural gas prices with higher (non-zero) carbon price at sub-hourly level for the 30% LOBO scenario.

The following observations are made on the simulation results:

- Several intervals with zero headroom
- Less headroom and higher LMP than corresponding baseline 30% LOBO case
- Significant real-time CT commitment in some intervals, but overall CT commitment is lower than corresponding baseline 30% LOBO case
- Violated line rating on one transmission line to arrive at a solution

The main difference between the 30% LOBO high carbon – low gas sub-hourly simulation and the baseline 30% LOBO simulation is the type of thermal unit commitment. Under the high carbon – low gas scenario, more combined cycle generators are committed and fewer steam turbines are committed. Figure 1-14 compares the MW dispatched for both steam and combined cycle generation for each of the two cases.

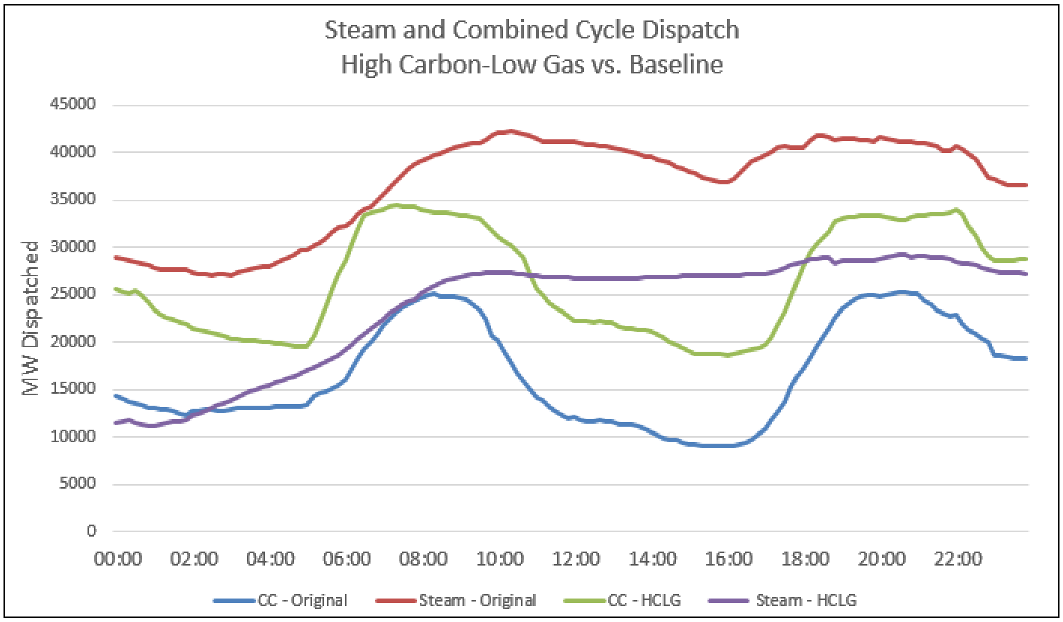

Figure 1-14: Steam/CC Dispatch by Interval (30% LOBO - February 17)

While the commitment change results in a higher LMP and slightly lower average headroom, the faster response time of combined cycle generation (i.e. higher ramp capability) also results in less need for CT commitment in real-time, with the exception of a few intervals. Overall, the total number of CTs required is 28% less and the total MWh from CT is 31% less than the baseline case. Figure 1-15 shows the CT dispatch between cases.

Similar to the baseline simulation, transmission overloads were experienced in solving this case. In this case, the overload observed was in a different location, reflecting the different unit commitment.

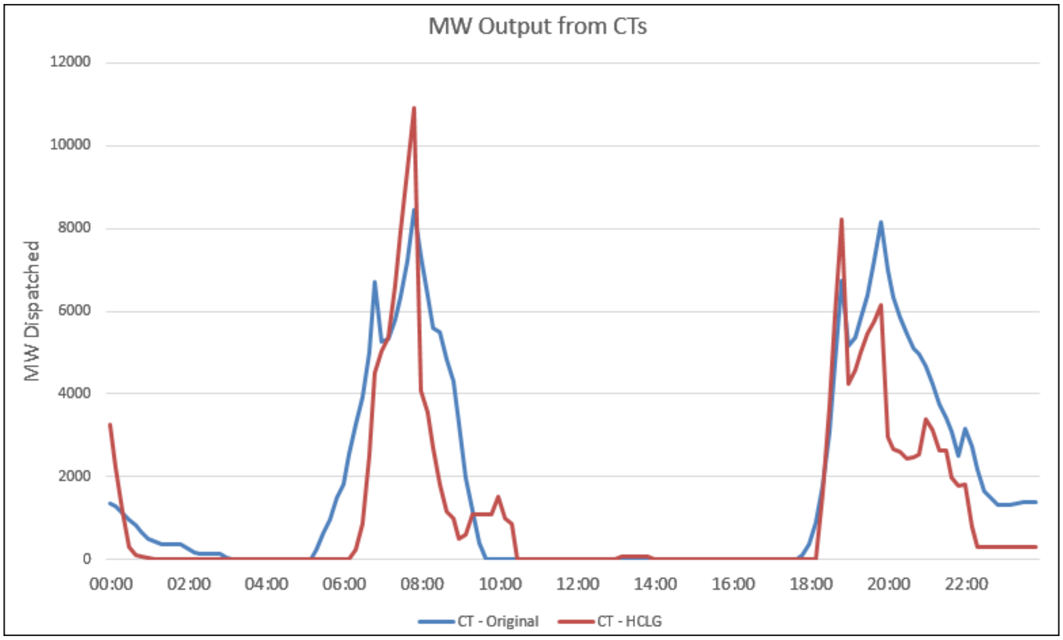

Figure 1-15: CT Dispatch by Interval (February 17)

1.3.6 Mid-Term Unit Commitment with Renewable Forecast

Results of the analysis in this section show that given the inherent uncertainty in day-ahead wind and solar forecasts, system operations can be improved if unit commitments are adjusted during the operating day when more accurate forecasts are available.

PJM already uses an application called Intermediate Term Security Constrained Economic Dispatch (IT SCED)[3]. IT SCED is used to commit CT's and guides the Real Time SCED (RT SCED) by looking ahead up to two hours. IT SCED creates a path for RT SCED to follow (the path is referred to as an Envelope).

However, IT SCED does not currently utilize any renewable generation forecast. Therefore, it is recommended that PJM consider using a renewable energy forecast in IT SCED. It may even be advisable to have a longer time horizon mid-term re-commitment process based on IT SCED (e.g., 4 hours-ahead) with updated wind and solar forecast. This process will allow for use of more accurate wind and solar forecasts in a time frame when commitments from intermediate units can still be adjusted.

This will enable shifting some energy from CTs to other more-efficient resources (e.g., combined cycle plants that can start in a few hours), hence, resulting, among other things, in

[3] "Real-time Security-Constrained Economic Dispatch and Commitment in the PJM: Experiences and Challenges", Simon Tam, Manager, Markets Coordination, PJM Interconnection, June 29, 2011.

significantly less CT commitment in real-time than the baseline 14% RPS simulation for this day, as measured both by number of CTs and MW dispatched from CTs.

The benefits of this practice would increase as wind and solar penetration increases.

2 Task 4: Mitigation, Facilitation and Report

2.1 Introduction to Task 4

This task is focused on investigation of changes to the infrastructure, and accompanying practices, that could improve system performance. Extensive investigation of market and operational mechanisms was performed in Task 3. Here, performance issues that surfaced in Task 3 are tested for effectiveness in relieving problems or improving performance.

2.1.1 Mitigation Tasks Performed

In performing this project, the GE Team came to the conclusion that PJM's current energy scheduling practices already incorporates recommendations from previous renewable energy integration studies, and hence the scope of this task was redefined, and based on discussions and agreement with PJM, the project team performed the following simulations to consider the impact of better renewable forecast and meeting reserve requirements by non-thermal resources (such as energy storage), to see if additional mitigation measures were required. Additional analysis included accounting for the cycling costs in the dispatch of generation, and consideration of limited ramp-rate capabilities of existing power plants. In summary, the following simulations were performed:

- Comparing 4-Hour Renewable Forecast and Perfect Renewable Forecast Improvement, based on hourly GE MAPS simulation applied to the 14% RPS Scenario.
- Comparing 20% Forecast Improvement and Perfect Renewable Forecast Improvement, based on hourly GE MAPS simulation applied to the 20% LOBO Scenario.
- Replacing the need for thermal generation to provide reserve by other resources (such as Energy Storage), based on hourly GE MAPS simulation applied to the 30% LOBO scenario.
- Explicitly accounting for cycling costs (as VOM adder) in hourly dispatch of generation, based on hourly GE MAPS simulation applied to the 30% LOBO scenario.
- Considering the impact of the limitations of ramp-rate capabilities of existing power plants, based on sub-hourly PROBE simulation applied to the 30% LODO scenario, on June 18.

2.2 Comparison of 4-Hour Forecast & Perfect Forecast (14% RPS Scenario)

The GE MAPS analysis of 4-Hour Forecast and Perfect Forecast evaluated the impact of less uncertainty and reduced wind and solar forecast error and benefit of a mid-term unit commitment on the system operations and economics.

The analysis was performed on the 14% RPS scenario, and the 4-Hour Forecast improvement only applied to PJM and not the rest of EI. This is because the 4-Hour Forecast was only available for PJM. However, the Perfect Forecast was applied to all of EI.

The 4-Hour Forecast simulation used a 4-hour forecast of renewable generation in unit commitment, and the actual hourly renewable generation for economic dispatch. The expected outcome would be a better commitment of thermal generation. The Perfect Forecast used the actual renewable generation for both unit commitment and economic dispatch. The results were compared to the original 14% RPS scenario simulation which used day-ahead forecast for unit commitment and actual renewable generation for economic dispatch.

The following observations are made on the simulation results:

- Primary impact is shift from More Imports to More Internal PJM Generation.
- Within PJM, compared to the original case, with the 4-Hour Forecast, generation of CCGT increased by 2.0 TWh, Coal increased by 4.7 TWh, SCGT decreased by 0.2 TWh, and Imports decreased by 6.7 TWh.
- Within PJM, compared to the original case, with the Perfect Forecast, generation of CCGT increased by 1.6 TWh, Coal increased by 3.3 TWh, SCGT decreased by 1.5 TWh, and Imports decreased by 3.7 TWh.
- The 4-Hour Forecast decreased PJM Production Costs by about $65M.
- The Perfect Forecast decreased PJM Production Costs by about $250M.

Figure 2-1 provides a comparison of generation by different unit types in the 14% RPS scenario under (a) original renewable forecast, (b) 4-Hour forecast, and (c) Perfect Forecast.

Figure 2-2 compares the PJM Production Cost in the 14% RPS scenario under (a) original renewable forecast, (b) 4-Hour forecast, and (c) Perfect Forecast.

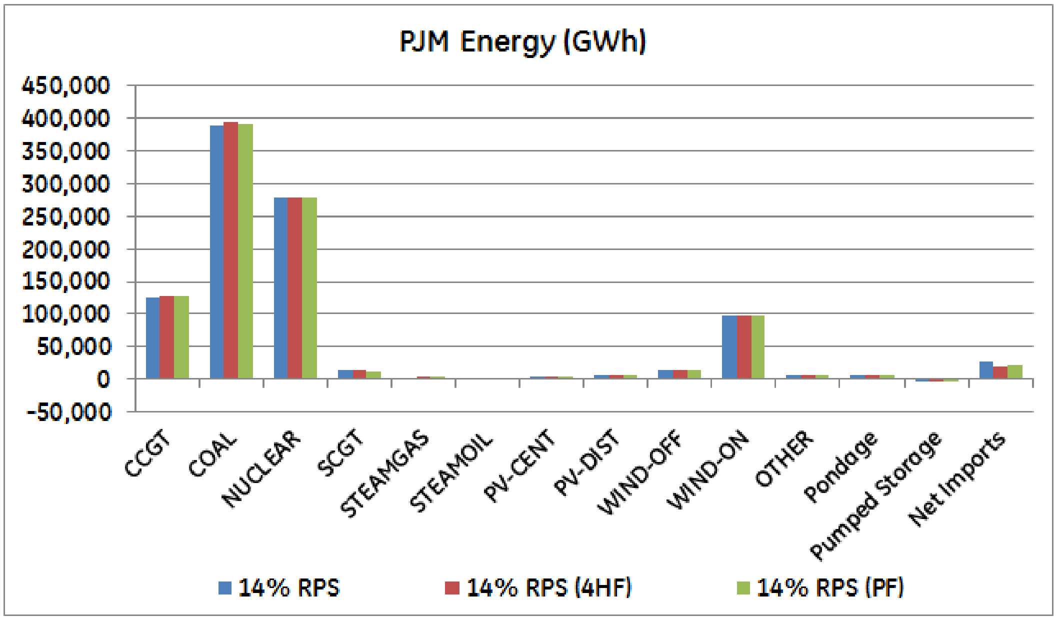

Figure 2-1: PJM Generation by Type in 14% RPS Scenario under Original Forecast, 4-Hour Forecast, and Perfect Forecast

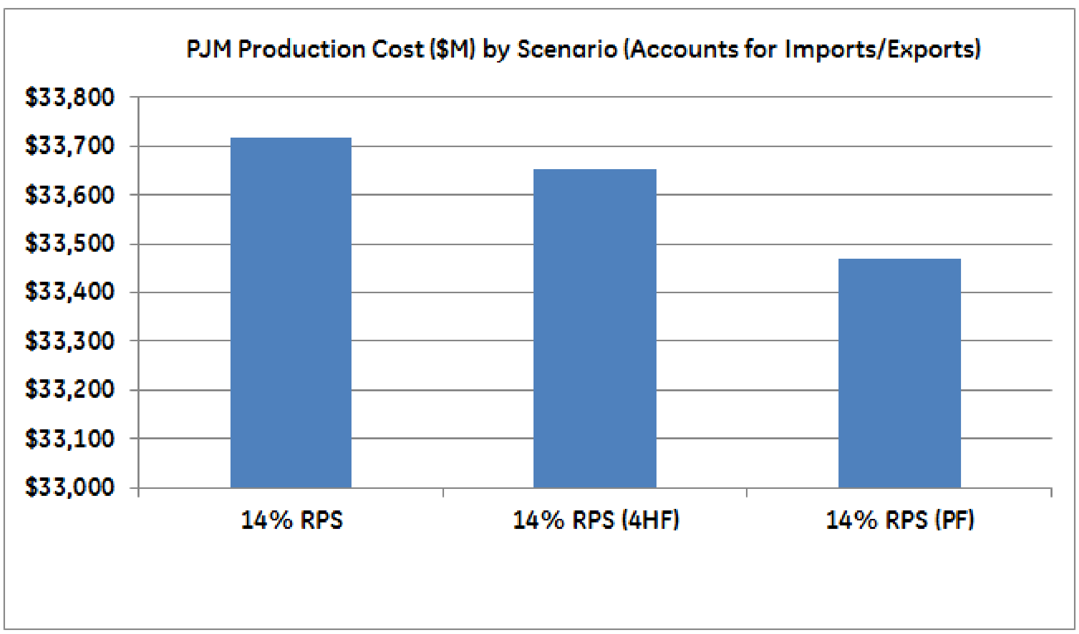

Figure 2-2: PJM Production Cost in 14% RPS Scenario under Original Forecast, 4-Hour Forecast, and Perfect Forecast

2.3 Comparison of 20% Forecast Improvement & Perfect Forecast (20% LOBO Scenario)

The GE MAPS analysis of 20% Forecast Improvement and Perfect Forecast also evaluated the impact of less uncertainty and reduced wind and solar forecast error and benefit of a better forecast on the system operations and economics.

The 20% Forecast Improvement used an adjusted renewable forecast, where the hourly difference between the original forecast and actual renewable generation was reduced by 20%. The analysis was performed on the 20% LOBO scenario. Both the 20% Forecast Improvement and Perfect Forecast were applied to all of EI.

The following observations are made on the simulation results:

- Within PJM, compared to the original case, with the 20% Forecast Improvement, CCGT generation increased by 0.4 TWh, Coal decreased by 0.3 TWh, and Imports decreased by 0.2 TWh.
- Within PJM, compared to the original case, with the Perfect Forecast, CCGT generation increased by 3.8 TWh, Coal increased by 0.3 TWh, and Imports decreased by 4.7 TWh.
- The 20% Forecast Improvement decreased PJM Production Costs by about $15M, whereas the Perfect Forecast decreased PJM Production Costs by about $73M.

Figure 2-3 provides a comparison of generation by different unit types in the 20% LOBO scenario under (a) original renewable forecast, (b) 20% Forecast Improvement, and (c) Perfect Forecast.

Figure 2-4 compares the PJM Production Cost in the 20% LOBO scenario under (a) original renewable forecast, (b) 20% Forecast Improvement, and (c) Perfect Forecast.

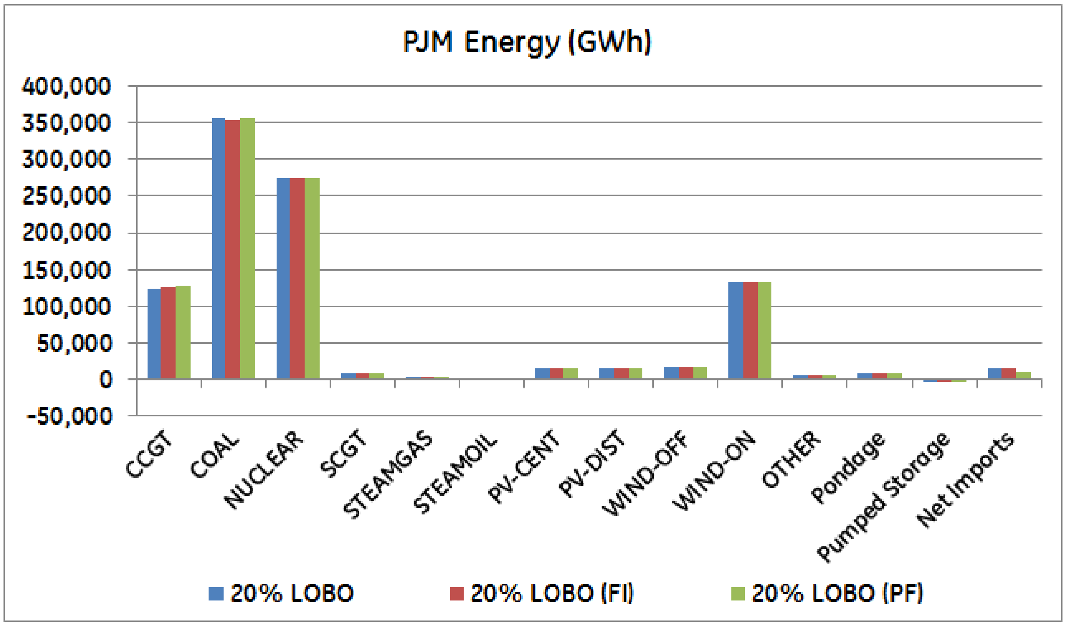

Figure 2-3: PJM Generation by Type in 20% LOBO Scenario under Original Forecast, 20% Forecast Improvement, and Perfect Forecast

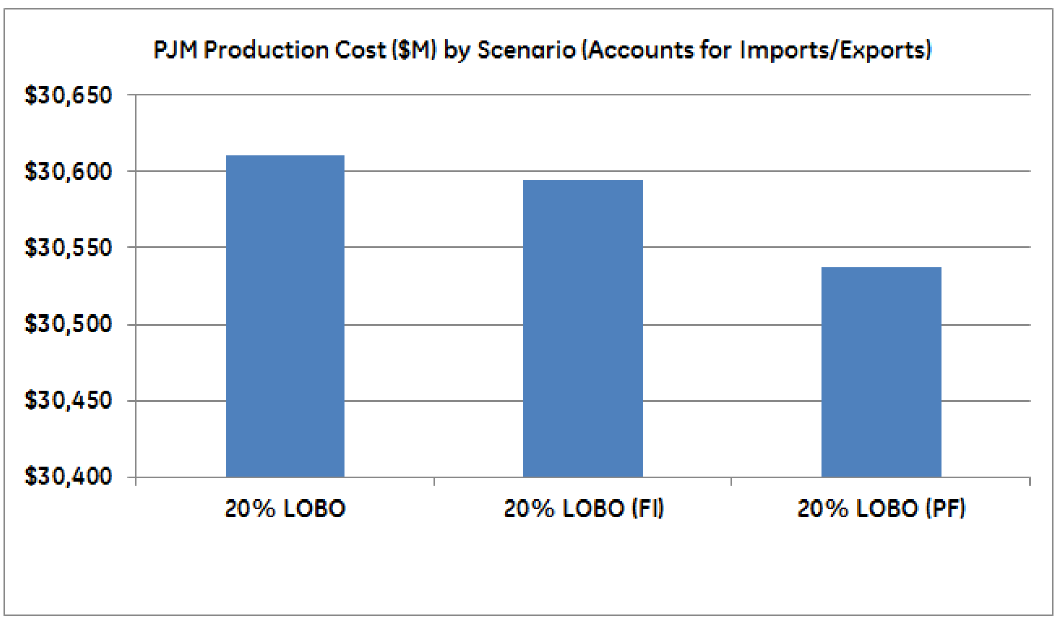

Figure 2-4: PJM Production Cost in 20% LOBO Scenario under Original Forecast, 20% Forecast Improvement, and Perfect Forecast

2.4 Improving Commitment of Generation Resources

All study scenarios (with the possible exception of 2% BAU) experienced operational challenges on days when wind and solar energy were over-forecast in the day-ahead market. Given PJM's substantial fleet of CTs, the study results showed no situations of unserved load or other unacceptable conditions, but operation was certainly less optimal than it could have been if other more-efficient generation resources could have been used to serve the load on those days. Two possible approaches to address this issue were investigated:

- Short-term recommitment using a 4-hour ahead wind and solar forecast
- Improvements in accuracy of the day-ahead wind and solar forecast

2.4.1 Short-Term Recommitment during Real-Time Operations

PJM's present practice is to commit most generation resources in the day-ahead forward market, and only commit combustion-turbine resources in the real-time market to make up for the normally small differences from the day-ahead forecast. When higher levels of renewable generation increase the levels of uncertainty in day-ahead forecasts, the present practice could lead to increased CT usage, in some cases for long periods of time where day-ahead wind and solar forecasts were off for many consecutive hours. In such circumstances, it would be more economical to commit other more efficient units, such as combined cycle plants that could be started in a few hours.

PJM production costs for the 14% RPS scenario were shown in Figure 2-2. The left bar represents the present practice. The middle bar represents the same case, but with unit commitments adjusted during real-time operations using a 4-hour ahead forecast. It shows a $70M reduction in annual production costs, largely due to shifting a portion of generation from CTs to combined cycle units and a reduction in PJM imports. This is further illustrated in Figure 2-5, which shows the change in CT dispatch for one day of operation in the 14% RPS scenario.

As a point of comparison, the right bar in Figure 2-2 shows that production costs would be reduced by $250M if perfect wind and solar forecasts were possible.

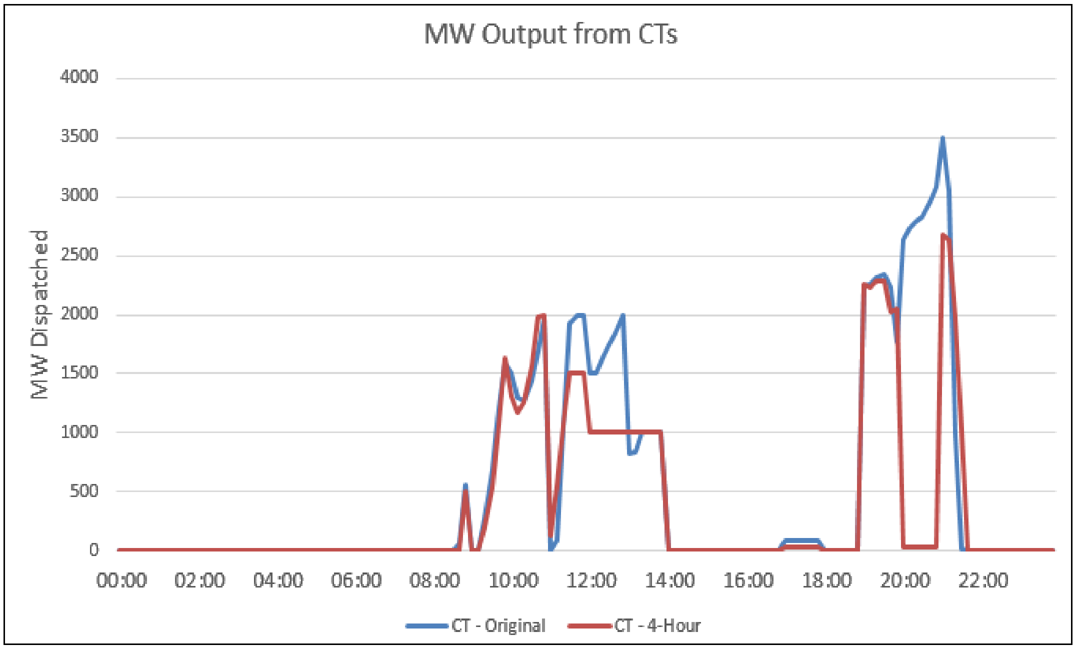

Figure 2-5: CT Dispatch for Existing Day-Ahead Unit Commitment Practice and 4-Hour-Ahead Recommitment (14% RPS Scenario, May 26)

2.4.2 Improvements in Day-Ahead Forecast Accuracy

Another approach to improve unit commitments and operational efficiency is to have a more accurate day-ahead wind and solar forecast. Study results indicate that a 20% reduction in day-ahead forecast errors could reduce annual production costs by about $15M per year in the 20% LOBO scenario. Although it is not realistic for PJM to independently procure such improved forecasting technology, PJM could actively encourage and participate in ongoing research efforts by NREL, NOAA, and others to develop improved wind and solar forecasting methods. The success of such efforts would directly benefit PJM and all other operating areas with increasing penetrations of wind and solar energy.

2.5 Energy Storage as Reserve (500 MW and 1000 MW ES) (30% LOBO Scenario)

There is a growing industry trend to use energy storage and demand response resources as an alternative to generation resources for spinning reserves. This study considered a case where 500 MW and a 1000 MW of storage or demand response resources were used in place of generator resources for spinning reserves in the 30% LOBO scenario.

These two sensitivity analyses with hourly GE MAPS simulation evaluated the impact of providing hourly reserve with Energy Storage (and freeing up equivalent amount of reserve set-aside by thermal generation) on the system operations and economics. In the simulation, the PJM reserve requirements were simply reduced by the equivalent amounts. Analysis was performed on the 30% LOBO scenario.

The following observations are made on the simulation results:

- 500 MW or even 1000 MW ES are too small compared to the system size to make any significant impact on PJM LMPs.
- ES for Reserve caused a small drop in PJM Total Production Cost:
- $6.96M with 500 MW ES
- $17.41M with 1000 MW ES
- This translates into:
- Value of 500 MW Storage of $1.59/MWh ($13.91/kW-Year),
- Value of 1000 MW Storage of $1.99/MWh ($17.41/kW-Year)
- Incremental value of going from 500 MW to 1000 MW Storage is $2.39/MWh

Figure 2-6 compares the PJM Production Cost under the different reserve requirements, with drop in requirements taken up by other non-thermal-generation resources in the system such as energy storage.

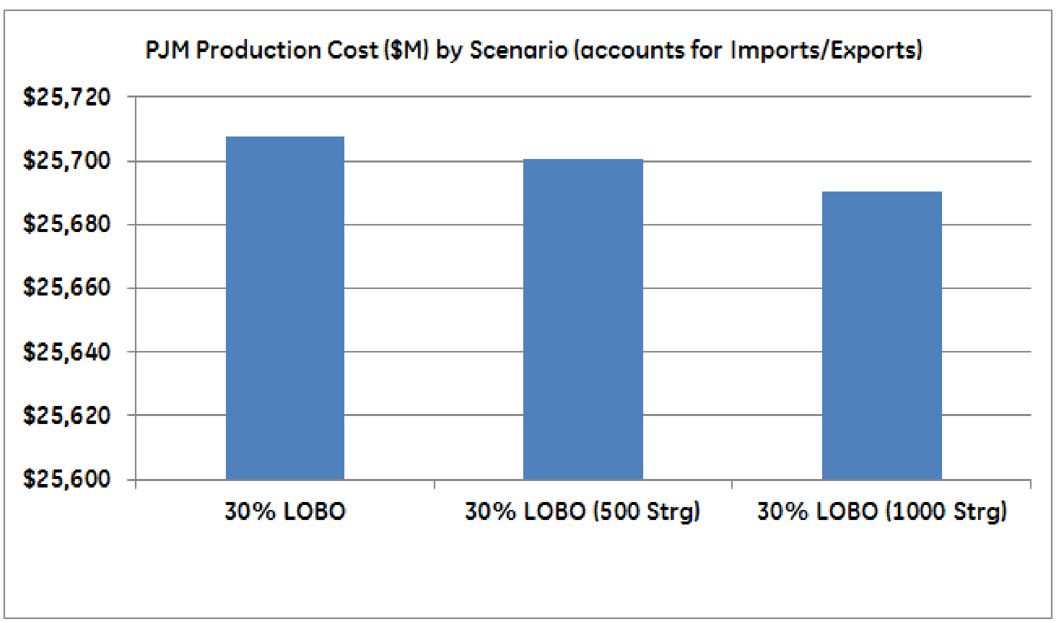

Figure 2-6: PJM Production Cost in 30% Lobo Scenario under Original Reserve Requirements and under Energy Storage as Reserve (500 MW & 1000 MW ES)

Energy storage resources are emerging as viable contributors to regulation reserves in some operating areas where the market prices of regulation services are adequate to make the capital investment worthwhile. This especially true in markets where the inherent fast-ramping capability of some storage technologies is financially rewarded (e.g., a mileage charge). Currently, energy storage is successfully participating in the PJM frequency regulation market.

This study did not include economic assessment of the regulation market in PJM, so no specific conclusions can be drawn with respect to the economic competitiveness of energy storage devices as regulation resources in PJM. The market price of regulation and the capital costs of energy storage devices will ultimately dictate viability.

The results of this analysis are specific to the particular application of energy storage examined, and do not represent a complete evaluation of energy storage benefits in PJM.

2.6 Accounting for Power Plant Cycling Costs (30% LOBO)

Start-up/shutdown cycles and load ramping impose thermal stresses and fatigue effects on numerous power plant components. When units operate at constant power output, these effects are minimized. If cycling duty increases, the fatigue effects increase as well, thereby requiring increased maintenance costs to repair or replace damaged components.

The section on power plant cycling discussed a technical approach to quantify the variable O&M (VOM) costs due to cycling for the various study scenarios.

Table 2-1 shows cycling VOM costs in $/MWh. In almost all of the scenarios, the coal and combined cycle units perform increasing amounts of cycling; resulting in higher cycling related VOM cost and reduced baseload VOM cost, where:

Total VOM Cost = Baseload VOM + Cycling VOM

Table 2-1: Variable O&M Costs ($/MWh) Due to Cycling Duty for Study Scenarios)

	2% BAU	14% RPS	20% HOBO	20% HSBO	20% LOBO	20% LODO	30% LOBO	30% HSBO	30% HOBO	30% LODO
Subcritical Coal	$1.14	$0.61	$1.78	$0.51	$0.69	$0.59	$1.09	$1.46	$2.52	$1.01
Supercritical Coal	$0.09	$0.11	$0.21	$0.15	$0.15	$0.14	$0.99	$0.31	$0.34	$0.46
Combined Cycle [GT+HRSG+ST]	$1.80	$2.69	$6.29	$5.19	$4.77	$4.68	$5.43	$7.55	$6.76	$5.81
Small Gas CT	$1.65	$1.74	$0.41	$0.52	$0.51	$0.60	$0.92	$0.87	$0.51	$0.82
Large Gas CT	$3.32	$3.41	$1.88	$2.68	$2.19	$2.42	$1.56	$1.52	$1.85	$2.02

Note: Cycling Costs = [Start/Stop + Significant Load Follow]

A sensitivity analysis was performed with hourly GE MAPS simulation evaluated the impact of including the power plant cycling costs as a $/MWh adder to the each plant type VOM (provided by Intertek AIM), using the data from the Power Plant Cycling Cost Analysis of this study. Analysis was performed on the 30% LOBO scenario.

Figure 2-7 shows the net effect when cycling costs are included in the calculation of total system production costs. The two bars on the left show the total production costs for the 2% BAU and 30% LOBO scenarios, without considering the "extra" wear-and-tear duty imposed by increased unit cycling. The two bars on the right show the total production costs for the 2% BAU and 30% LOBO scenarios, with the "extra" wear-and-tear duty imposed by increased unit cycling. The 2% BAU production costs increase by about $0.87B from $40.47B to $41.34B, an increase of about 2.1%. The 30% LOBO production costs increase by about $0.50B from $25.71B to $26.21B, an increase of about 1.9%.

Looking at the two cases (with and without cycling costs) separately, it can be seen that the increased renewables in the 30% scenario reduce annual PJM production costs by $14.76B. If the VOM costs due to cycling are included in the calculation (the right-side bars), the increased renewables in the 30% scenario reduce annual PJM production costs by $15.13B.

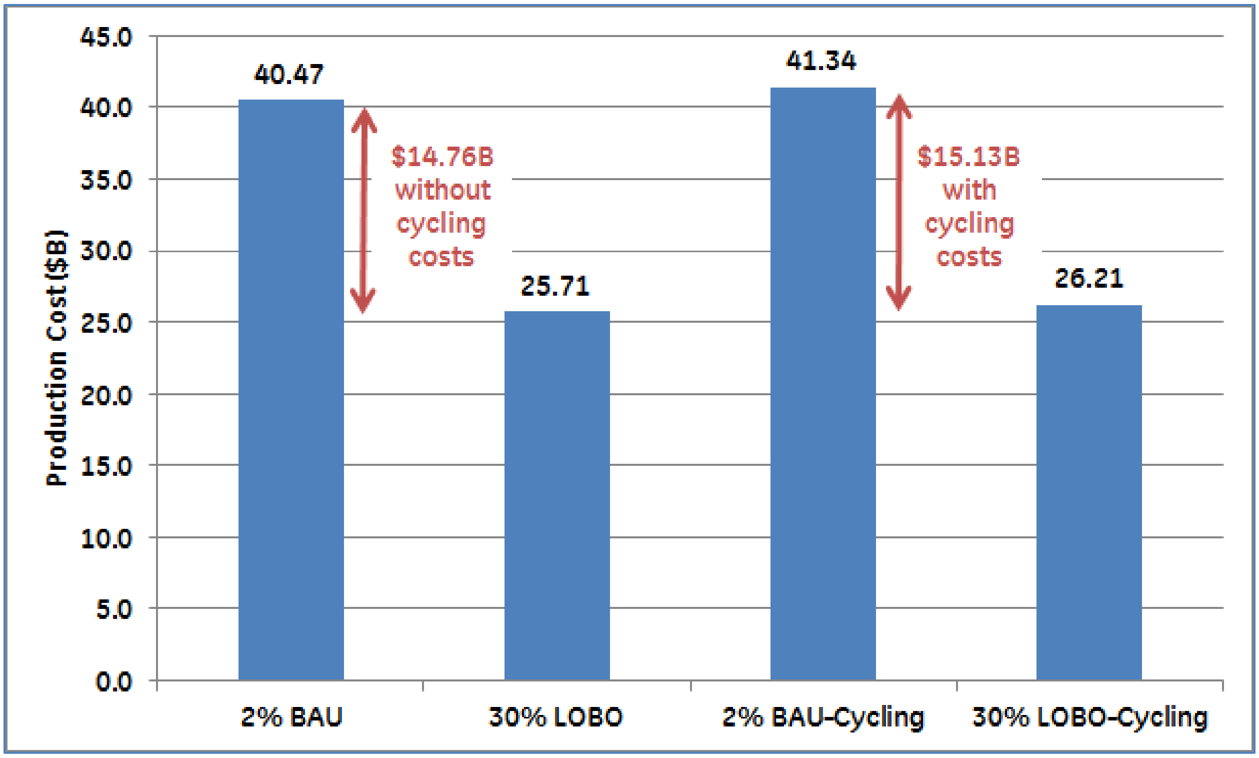

Figure 2-7: Impact of Cycling Effects on Total Production Costs for 2% BAU and 30% LOBO Scenarios

2.7 Sub-Hourly Simulation of Increased Ramp Rates

2.7.1 Simulation of 30% LODO Scenario – June 18

The purpose of this sub-hourly sensitivity is to study how faster ramp rates may improve real-time operations, considering that ramp rates were frequently observed as a limiting factor in most sub-hourly simulations. The following improvements were observed using the faster ramp rates.

The sub-hourly analysis revealed a number of operating conditions where the system was constrained by the ability of the committed power plants to keep up with changes in net load. The power plants were ramp-rate limited. Investigation of these periods revealed that some power plants have very small ramp rates – significantly below 2% per minute, which is considered to be typical for steam power plants.

The general observed highlights include:

- A 51% reduction in ramp constrained generation
- Fewer CTs committed
- Lower LMPs and fewer transmission constraints

- More operating flexibility

Ramp constraints were one of the main operational challenges during the original baseline sub-hourly-simulation for June 18, 30% LODO, but the faster ramp rates in this simulation alleviated nearly all real-time operational challenges.

Figure 2-8 shows the number of ramp constrained units for a day of operation in the 30% LODO scenario. The blue trace corresponds to the existing ramp-rate limits and the red traces shows a case where all ramp rates limits smaller than 2%/min were increased to 2%/min. The results of this analysis show a 51% reduction in ramp-constrained generation, fewer CTs get committed, lower LMPs, fewer transmission constraints, and more operating flexibility.

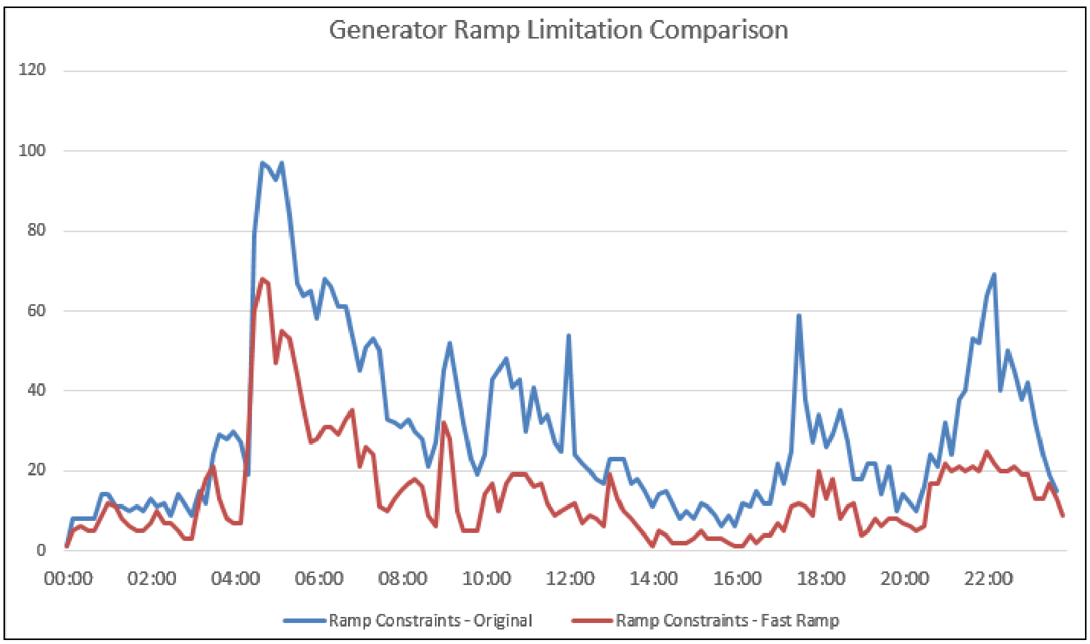

Figure 2-8: Number of Ramp Constrained Units with Existing Ramp Limits and 2%/min Ramp Limits

Figure 2-9 compares LMP between the two cases.

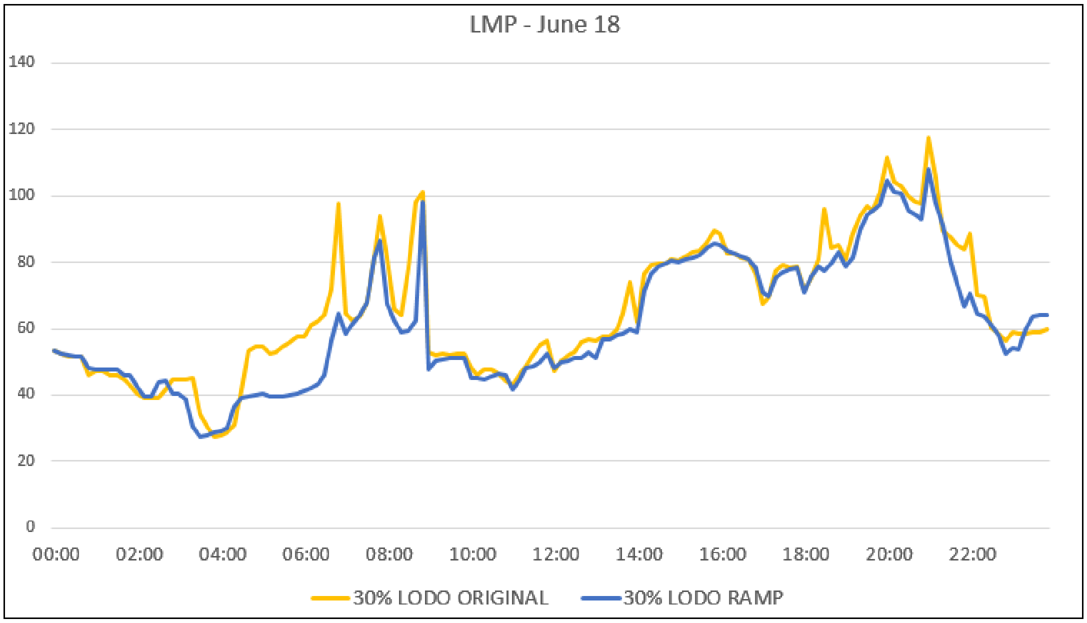

Figure 2-9: LMP Comparison for June 18

2.7.2 Recommendation on Ramp Rate Capabilities

The results suggest that it would be beneficial for PJM to reevaluate the capability and performance of units with ramp rates that are below the fleet average. Experience from other operating areas has shown that power plant operators prefer to operate at constant outputs and have little or no incentive to ramp their units quickly. As a result, ramp limits may be set to a conservative low value. It would be prudent for PJM to learn more about the factors affecting ramping performance of its generation fleet to prepare for a future when faster ramping would be beneficial to renewable energy integration.

2.8 Key findings of Mitigation Analysis

- Further Support for Mid-Term Commitment & Better Wind/Solar Forecast
  - Addition of a mid-term commitment (e.g., 4 hours-ahead) with updated wind and solar forecast will allow for use of more accurate wind and solar forecasts in a time frame when commitments from intermediate units can still be adjusted, resulting in significantly less CT commitment in real-time.
- Benefits of Energy Storage to Provide Reserve
  - Reduction in regulation reserve requirements by using Energy Storage caused a small drop in PJM total production cost. These results should not be

generalized, since we did not evaluate the benefits of the full range of service offerings of energy storage in PJM.

- Power Plant Cycling
  - Cycling Costs when accounted for as VOM adders reduces by about 10% the reduction in Production Costs of 30% LOBO relative to 2% BAU scenarios.
- Improved Ramp Rate
  - Improving Ramp rates of large Coal Plants would result in reduction in ramp constrained generation, fewer CTs get committed, lower LMPs, less congestion, and more flexible operations.

imagination at work