GE
Energy Consulting

PJM Renewable Integration Study

Executive Summary Report

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imagination at work

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1 Project Overview

At the request of its stakeholders, PJM Interconnection, LLC. (PJM) initiated this study to perform a comprehensive impact assessment of increased penetrations of wind and solar generation resources on the operation of the PJM grid. The principal objectives include:

- Determine, for the PJM balancing area, the operational, planning, and energy market effects of large-scale integration of wind and solar power as well as mitigation/facilitation measures available to PJM
- Make recommendations for the implementation of such mitigation/facilitation measures

This study is motivated by the need for PJM to be prepared for a considerably higher penetration of renewable energy in the next 10 to 15 years. Every jurisdiction within the PJM footprint, except for Kentucky and Tennessee, has a renewable portfolio standard (RPS), or Alternative Energy Portfolio Standard (AEPS), or non-binding Renewable Portfolio Goal (RPG)[1].

This study investigates operational, planning, and energy market effects of large-scale wind/solar integration, and makes recommendations for possible facilitation/mitigation measures. It is not a detailed near-term planning study for any specific issue or mitigation. The target year is 2026, which was used to estimate the PJM annual load profile used in the study scenarios.

The growth of renewable energy is largely driven by Renewable Portfolio Standards and other legislative policies. The cost-benefit economics of renewable resources, and quantifying the capital investment required to install additional wind and solar infrastructure, were beyond the scope of this study and were not investigated. The study assumed that the penetration of renewable resources would increase and investigated how the PJM system would be affected.

The impact of renewables on production cost savings was investigated, but the analysis did not include possible secondary impacts to the capacity market such as increased retirements due to non-economic performance or a possible need for generators to recover more in the capacity market because of reduced revenue in the energy market.

Project Team

Six companies joined forces to execute the broad range of technical analysis required for this study.

[1] www.dsireusa.org

- GE Energy Consulting – overall project leadership, production cost and capacity value analysis
- AWS Truepower – development of wind and solar power profile data
- EnerNex – statistical analysis of wind and solar power, reserve requirement analysis
- Exeter Associates – review of industry practice/experience with integration of wind/solar resources
- Intertek Asset Integrity Management (Intertek AIM), formerly APTECH – impacts of increased cycling on thermal plant O&M costs and emissions
- PowerGEM – transmission expansion analysis, simulation of sub-hourly operations and real-time market performance

Data Sources

This study used a combination of publicly available and confidential data to model the Eastern Interconnection, the PJM grid, and its power plants. The hourly production simulation analysis was performed using GE's Concorda Suite Multi-Area Production Simulation (GE MAPS) model. In order to protect the proprietary interests of PJM stakeholders, the production simulation analysis was primarily based on publically available data, reviewed and vetted by PJM to assure consistency with the operating characteristics of the PJM grid and the power plants under its control. The sub-hourly analysis used PowerGEM's Portfolio Ownership and Bid Evaluation (PROBE) program, which is regularly used by PJM to monitor the performance of the real-time market[2]. PROBE uses proprietary power plant data, but that data was not shared with any other study team members per PJMs existing non-disclosure agreement with PowerGEM.

AWST provided wind and solar power generation profiles and power forecasts within the PJM interconnection region, as well as the rest of the Eastern Interconnection, as inputs to hourly and sub-hourly grid simulations. These data sets were based on high-resolution simulations of the historical climate performed by a mesoscale numerical weather prediction (NWP) model covering the period 2004 to 2006.

Meteorological data from NREL's EWITS project[3] was used to produce power output profiles for both wind and solar renewable energy generation facilities. A site selection process was completed for onshore and offshore wind as well as for the centralized and distributed solar sites within the PJM region. The selection includes sites that could be developed to meet and

[2] PowerGEM website, http://www.power-gem.com/PROBE.htm

[3] http://www.nrel.gov/docs/fy11osti/47078.pdf

exceed renewable portfolio standards for the PJM Interconnection. Power output profiles were produced for each of the sites using performance characteristics from the most current power conversion technologies as of July 2011. The resulting wind and solar power profiles were validated against measurements.

2 Study Scenarios

Table 1 summarizes the PJM wind and solar installed capacity for the ten study scenarios. Note that the scenarios are defined in terms of percentage of renewable energy generation (MWh), whereas Table 1 summarizes the wind and solar capacity (MW) in each scenario. Also, all scenarios include 1.5% of non-wind, non-solar renewable generation.

2% BAU: This is a Business As Usual (BAU) reference case with the existing level of wind/solar in year 2011. This case is a benchmark for how PJM operations will change as wind and solar penetration increases.

14% RPS: Wind and solar generation meets existing RPS mandates by 2026, with 14% renewable energy penetration in PJM.

20% LOBO: 20% wind and solar energy penetration in PJM, Low Offshore and Best Onshore; 10% of wind resources are offshore, 90% of wind resources are onshore in locations with best wind quality.

20% LODO: 20% wind and solar energy penetration in PJM, Low Offshore and Dispersed Onshore; 10% of wind resources are offshore, 90% of wind resources are onshore. Incremental onshore wind added in proportion to load energy of individual states.

20% HOBO: 20% wind and solar energy penetration in PJM, High Offshore and Best Onshore; 50% of wind resources are offshore, 50% of wind resources are onshore in locations with best wind quality.

20% HSBO: 20% wind and solar energy penetration in PJM, High Solar and Best Onshore; similar to 20% LOBO, but with twice the solar energy and proportionately less wind energy.

The 30% scenarios are similar to the 20% scenarios, but with more wind and solar resources to achieve 30% wind and solar energy penetration in PJM.

Table 1: Total PJM Wind and Solar Capacity for Study Scenarios

Scenario	Renewable Penetration in PJM	Onshore Wind (MW)	Offshore Wind (MW)	Centralized Solar (MW)	Distributed Solar (MW)	Total (MW)
2% BAU	2%	5,122	0	72	0	5,194
14% RPS	14%	28,834	4,000	3,254	4,102	40,190
20% LOBO	20%	39,452	4,851	8,078	10,111	62,492
20% LODO	20%	40,942	4,851	8,078	10,111	63,982
20% HOBO	20%	21,632	22,581	8,078	10,111	62,402
20% HSBO	20%	32,228	4,026	16,198	20,294	72,746
30% LOBO	30%	59,866	6,846	18,190	16,907	101,809
30% LODO	30%	63,321	6,846	18,190	16,907	105,264
30% HOBO	30%	33,805	34,489	18,190	16,907	103,391
30% HSBO	30%	47,127	5,430	27,270	33,823	113,650

Figure 1 shows the locations of wind plants for the 14% RPS scenario. Note the high concentration of wind plants in Illinois, Indiana and Ohio, which have high quality wind resources. Other study scenarios where onshore wind resources were selected based on a "best sites" criteria also have high concentrations of wind plants in these western PJM states. Scenarios with the "dispersed sites" criteria moved some of the Illinois and Indiana wind resources eastward, to Ohio, Pennsylvania, and West Virginia.

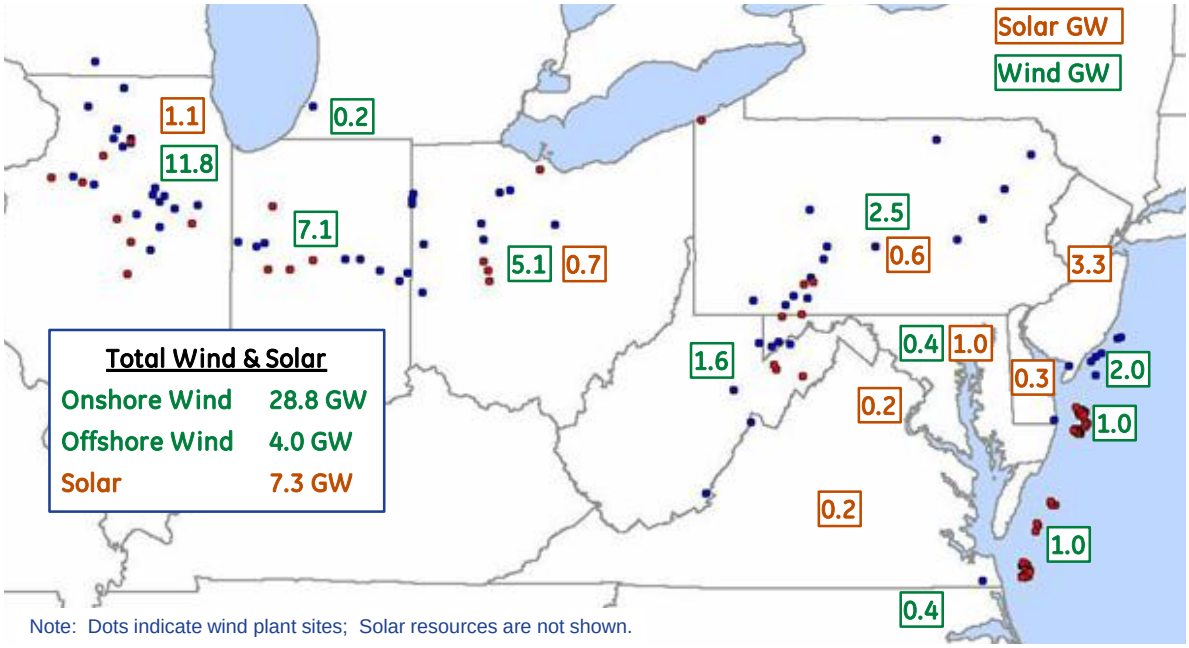

Figure 1: PJM Wind and Solar Capacity by State for 14% RPS Scenario

Most of the scenario technical analysis was performed using wind, solar and load profiles from year 2006. Four scenarios (2% BAU, 14% RPS, 20% LOBO, and 30% LOBO) were analyzed with 2004, 2005, and 2006 renewable and load profiles, in order to quantify differences in performance using different profile years. Although there were some observable differences in operational and economic performance due to differences in wind and solar production across the three profile years, the overall impacts were relatively small and did not affect the study conclusions.

3 Study Assumptions

PJM annual load energy was extrapolated to the study year 2026 using a method to retain critical daily and seasonal load shape characteristics. The average annual load growth for PJM was assumed to be 1.1%[4]. Load for the rest of the Eastern Interconnection was based on Ventyx "Historical and Forecast Demand by Zone".

New thermal generators (about 35 GW of SCGT and 6 GW of CCGT) were added to the PJM system in the 2% BAU scenario to meet the reserve margin requirements in 2026 consistent

[4] The base case assumed a PJM net energy forecast of 969,596 GWh in 2026 (excluding EKPC) based on the 2011 PJM Load Forecast Report (January 2011). The 2014 Preliminary PJM Load Forecast report shows a net energy forecast of 889,841 GWh in 2026 excluding EKPC, i.e., a reduction of 8.2%.

with the assumed load growth (for a total of about 65 GW of SCGT and 38 GW of CCGT). For consistency across scenarios, the new thermal generators added to meet reserve requirements in the 2% BAU scenario remained available in all higher renewable penetration scenarios. The additions included ISA/FSA qualified plants from the PJM queue, but rest of the additions were not reflective of other future projects in the PJM queue.

Some existing PJM power plants were assumed to retire by 2026, per retirement forecast data from PJM and Ventyx.

All operating power plants were assumed to have the necessary control technologies to be compliant with emissions requirements. No emission or carbon costs were assumed in the base scenarios although Carbon costs were considered in one of the sensitivity cases.

Fuel prices used for production cost simulations are shown in Table 2.

Table 2: Forecasted Fuel Prices for Study Year 2026

Fuel Type	Nominal Price	Source	Comments
Natural Gas	$8.02/MMBtu	EIA 2012 Energy Outlook	At Henry Hub; Regional basis differentials provided by PJM
Coal	$3.51/MMBtu	EIA 2012 Energy Outlook	Adjusted to reflect regional price differences ($1.15 to $6.08) per Ventyx historical usage data
Nuclear	$0.75/MMBtu	Ventyx Energy Velocity Forecast	
Residual No.2 Oil	$15.04/MMBtu	Energy Velocity NYMEX Forecast	Adjusted to include monthly variation patterns ($14.92 to $15.20)
LS No.2 Diesel	$22.56/MMBtu	Energy Velocity NYMEX Forecast	Adjusted to include monthly variation patterns ($22.37 to $22.79)

The wind profiles produced for this study used performance characteristics from the most current power conversion technologies as of July 2011. Therefore, the power output profiles are slightly higher than what has been historically observed in PJM.

4 Major Conclusions and Recommendations

A brief summary of the major conclusions and recommendations are listed here. Further details are presented in subsequent sections of this report.

Conclusions

The study findings indicate that the PJM system, with adequate transmission expansion and additional regulating reserves, will not have any significant issues operating with up to 30%

of its energy provided by wind and solar generation. The amount of additional transmission[5] and reserves required are briefly defined later in this summary and in much greater detail in the main body of the report.

- Although the values varied based on total penetration and the type of renewable generation added, on average, 36% of the delivered renewable energy displaced PJM coal fired generation, 39% displaced PJM gas fired generation, and the rest displaced PJM imports (or increased exports).
- No insurmountable operating issues were uncovered over the many simulated scenarios of system-wide hourly operation and this was supported by hundreds of hours of sub-hourly operation using actual PJM ramping capability.
- There was minimal curtailment of the renewable generation and this tended to result from localized congestion rather than broader system constraints.
- Every scenario examined resulted in lower PJM fuel and variable Operations and Maintenance (O&M) costs as well as lower average Locational Marginal Prices (LMPs). The lower LMPs, when combined with the reduced capacity factors, resulted in lower gross and net revenues for the conventional generation resources. No examination was made to see if this might result in some of the less viable generation advancing their retirement dates.
- Additional regulation was required to compensate for the increased variability introduced by the renewable generation. The 30% scenarios, which added over 100,000 MW of renewable capacity, required an annual average of only 1,000 to 1,500 MW of additional regulation compared to the roughly 1,200 MW of regulation modeled for load alone. No additional operating (spinning) reserves were required.
- In addition to the reduced capacity factors on the thermal generation, some of the higher penetration scenarios showed new patterns of usage. High penetrations of solar generation significantly reduced the net loads during the day and resulted in economic operation which required the peaking turbines to run for a few hours prior to sun up and after sun set rather than committing larger intermediate and base load generation to run throughout the day.
- The renewable generation increased the amount of cycling (start up, shut down and ramping) on the existing fleet of generators, which imply increased variable O&M costs on these units. These increased costs were small relative to the value of the fuel displacement and did not significantly affect the overall economic impact of the renewable generation.

[5] This study did not examine the cost allocation for the transmission expansion required to deliver the renewable energy in the study scenarios.

- While cycling operations will increase a unit's emissions relative to steady state operations, these increases were small relative to the reductions due to the displacement of the fossil fueled generation.

Recommendations

Adjustments to Regulation Requirements

The amount of regulation required by the PJM system is highly dependent upon the amount of wind and solar production at that time. It is recommended that PJM develop a method to determine regulation requirements based on forecasted levels of wind and solar production. Day-ahead and shorter term forecasts could be used for this purpose.

Renewable Energy Capacity Valuation

Capacity value of renewable energy has a slightly diminishing return at progressively higher penetration, and the LOLE/ELCC approach provides a rigorous methodology for accurate capacity valuation of renewable energy.

PJM may want to consider an annual or bi-annual application of methodology in order to calibrate its renewable capacity valuation methodology in order to occasionally adjust the applicable capacity valuation of different classes of renewable energy resources in PJM.

Mid-Term Commitment & Better Wind and Solar Forecast

Inherent errors in the day-ahead forecasts for wind and solar production lead to suboptimal commitment of generation resources in real-time operations, especially if simple cycle combustion turbines are the primary resources used to compensate for any generation shortages. Wind and solar forecasts are much more accurate in the four- to five-hour-ahead timeframe than in the current day-ahead commitment process. It is recommended that PJM consider using such a mid-range forecast in real-time operations to update the commitment of intermediate units (such as combined cycle units that could start in a few hours). The wind and solar forecast feature can be added to the current PJM application called Intermediate Term Security Constrained Economic Dispatch (IT SCED)[6] which is used to commit CT's and guides the Real Time SCED (RT SCED) by looking ahead up to two hours. This would result in less reliance on higher cost peaking generation.

Exploring Improvements to Ramp Rate Performance

Ramp-rate limits on the existing baseload generation fleet may constrain PJM's ability to respond to rapid changes in net system load in some operating conditions. It is

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

recommended that PJM explore the reasons for ramping constraints on specific units, determine whether the limitation are technical, contractual, or otherwise, and investigate possible methods for improving ramp rate performance.

5 Statistical Characteristics of Load, Wind and Solar Profiles

A wide variety of statistical evaluations were performed on the load, wind and solar profiles to build understanding on how they would impact the annual, seasonal, daily, and short-term operation of the PJM grid. A few examples are presented here.

Figure 2 exhibits duration curves of load-net-renewables (wind + solar), which show the portion of the PJM load that must be served by non-renewable generation resources. The right-hand portions of the curves show that in the higher penetration scenarios, renewables serve about half of total system load during low-load periods.

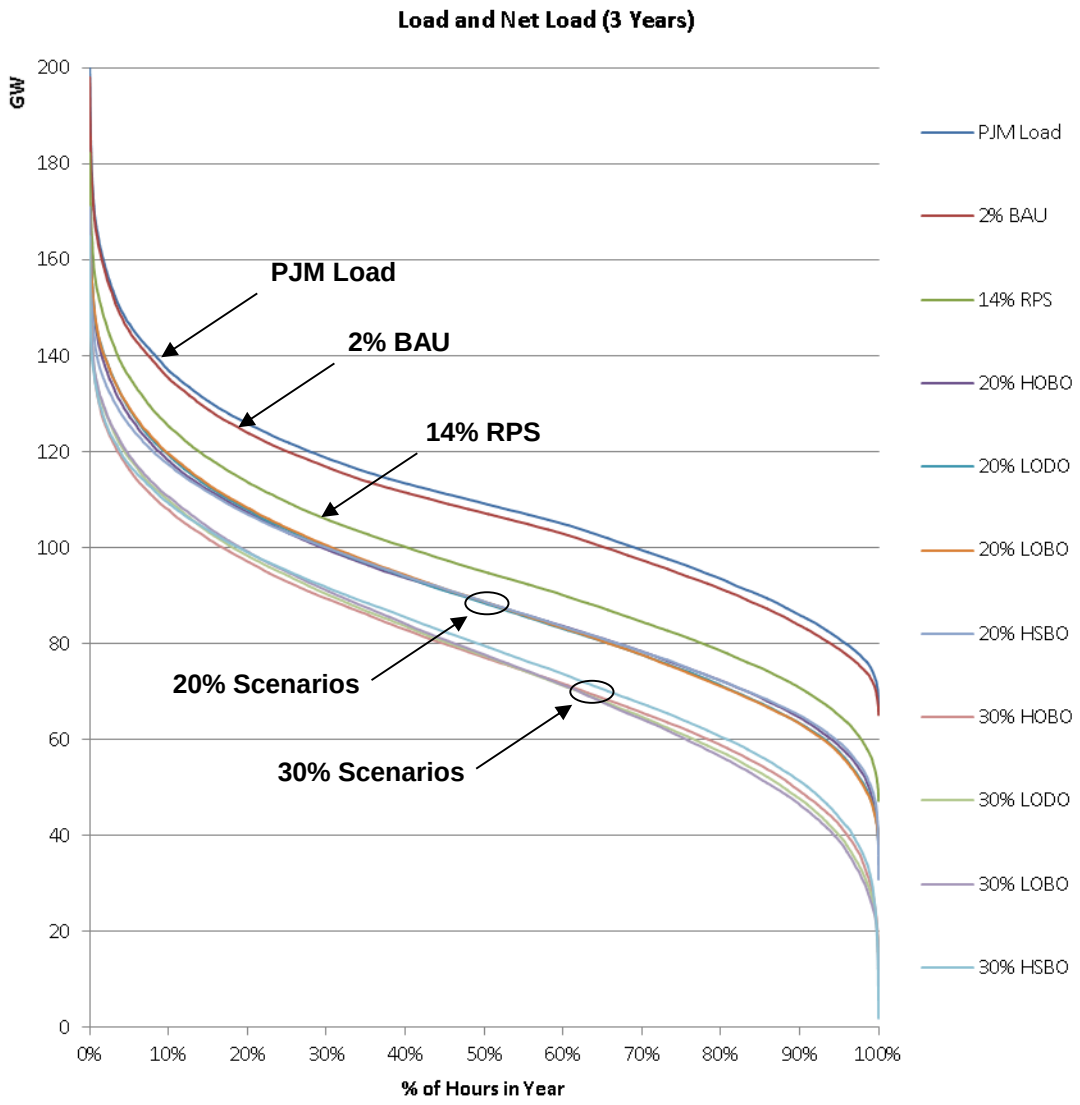

Figure 2: Duration Curves of PJM Load and Load-Net-Renewables for Study Scenarios

Figure 3 shows 10-minute variability (i.e., the change in 10-minute renewable production from one 10-minute period to the next) as a function of total renewable production for three scenarios with increasing renewable penetration (2%, 14%, and 30%). One significant trend is that the maximum 10-minute variations occur when renewable production is about half of total renewable capacity. Variability is lower near maximum production levels, partly because many wind plants are operating above the knee in the wind-power curve where changes in wind speed do not affect electrical power output. This characteristic of variability is relevant to the regulation requirements, which is discussed later.

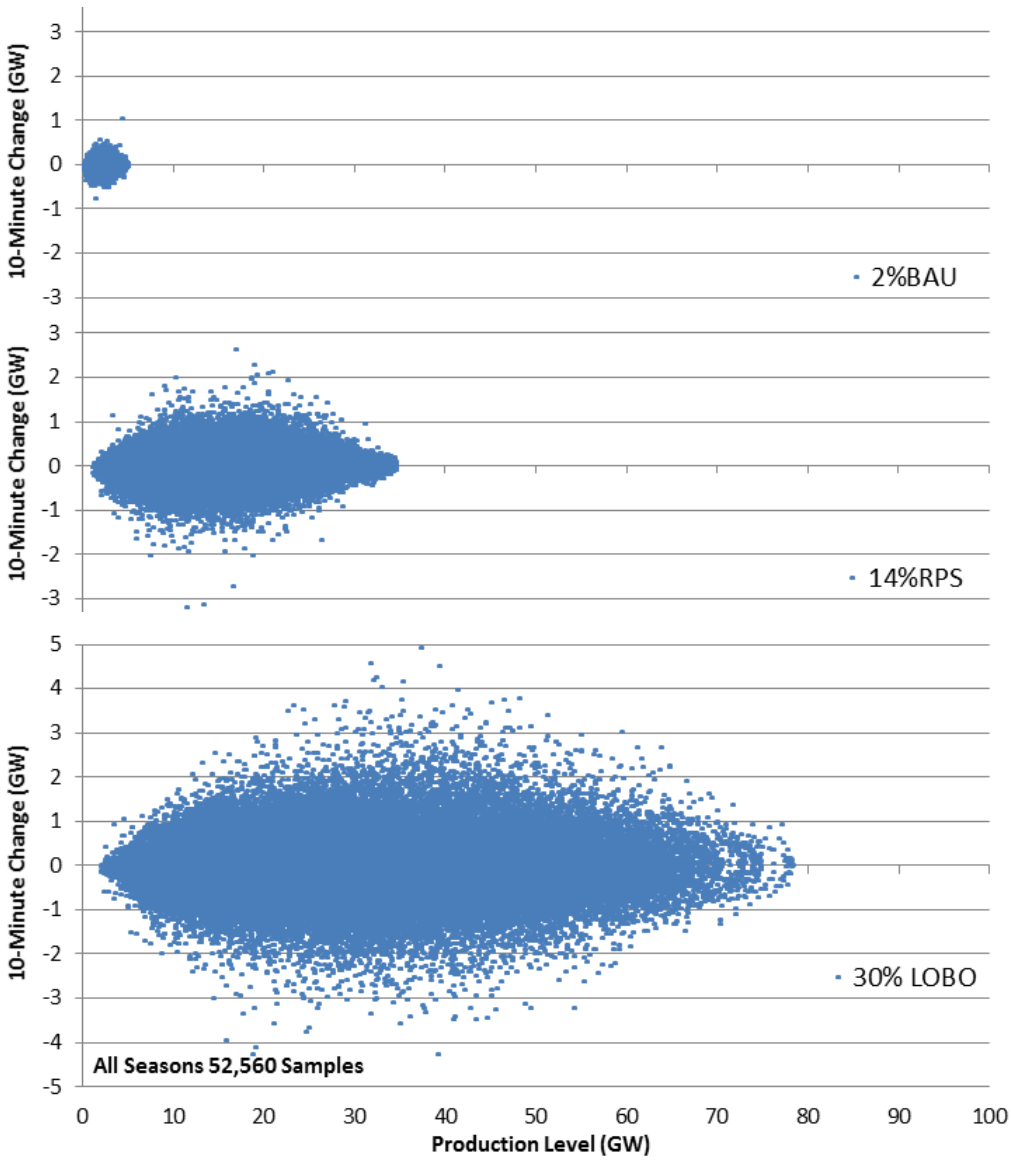

Figure 3: Ten-Minute Wind and Solar Variability as Function of Production Level for Increasing Renewable Penetration

Figure 4 shows average daily wind profiles by season for two scenarios. The trends show lower power output during the midday hours, especially during the summer season. This trend is complementary to solar profiles which naturally peak during midday and have higher production during the summer season.

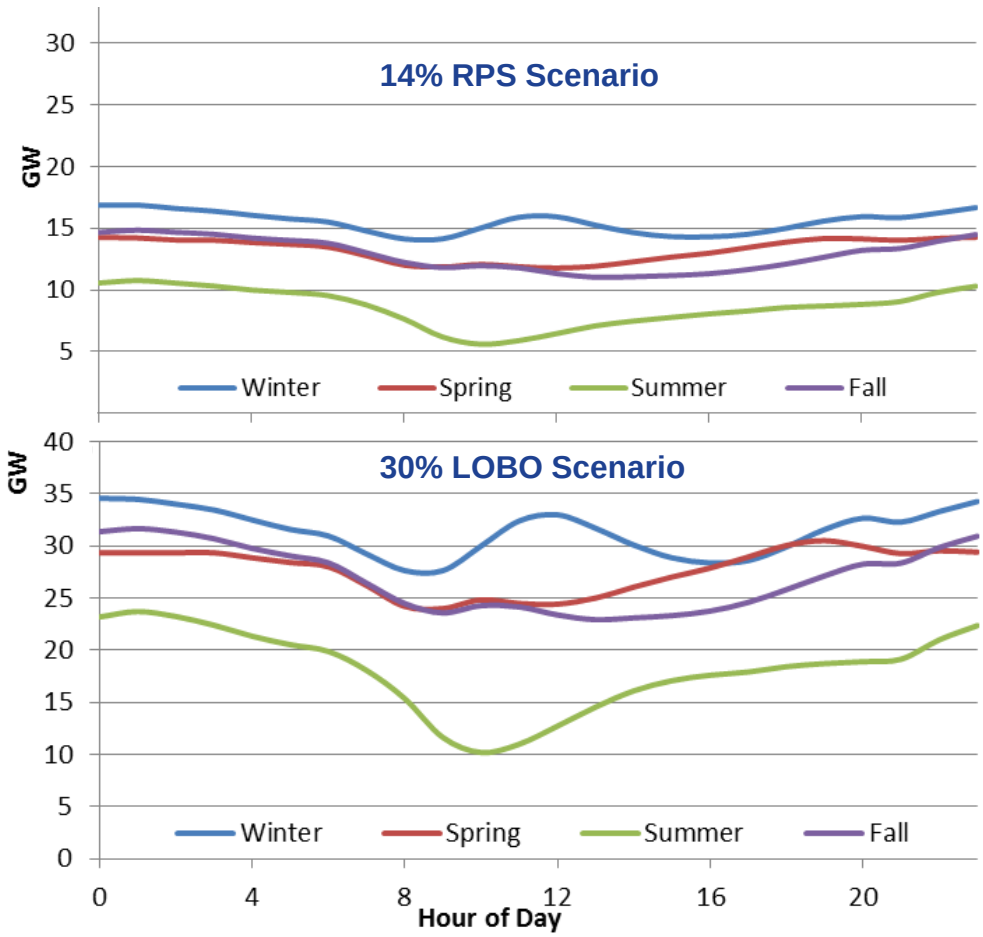

Figure 4: Average Daily Wind Profile by Season for 14% RPS and 30% LOBO Scenarios

Figure 5 illustrates how the variability of individual wind and solar PV plants is reduced when all wind and solar PV plants are aggregated over PJM's footprint. The upper traces show the high variability associated with individual plants. The two wind plants and the Illinois solar plant show high short term variability. The New Jersey solar plant has a smooth profile, indicating a relatively clear or hazy day. The next traces below show the aggregate profiles for all wind and solar plants within the states of New Jersey, Pennsylvania, and Illinois. The lower traces show profiles for all wind plants in PJM, all PV plants in PJM, and the combination of all wind and PV plants in PJM. Short-term variability is dramatically reduced when aggregated across PJM's footprint. Values shown are in terms of per units of capacity ratings. PJM's large geographic footprint is of significant benefit for integrating wind and solar generation, and greatly reduces the magnitude of variability-related challenges as compared to smaller balancing areas.

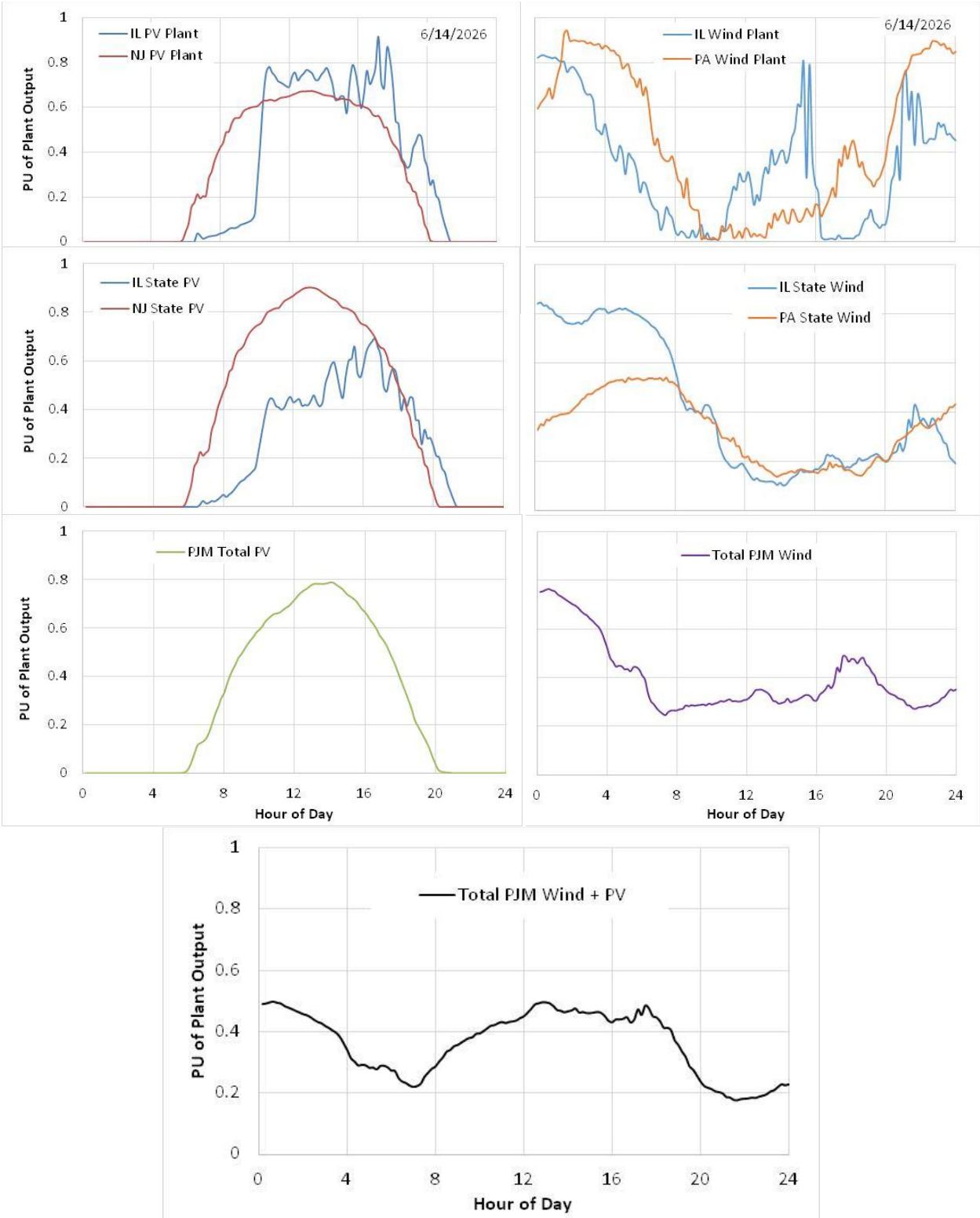

Figure 5: Smoothing of Plant-Level 10-Minute Variability over PJM's Footprint, June 14, 30% LOBO

6 Regulation and Reserves

With increasing levels of wind and solar generation, it will be necessary for PJM to carry higher levels of reserves to respond to the inherent variability and uncertainty in the output of those resources. Currently PJM has four categories of ancillary services:

- Regulation, which include generating units or demand response resources that are under automatic control and respond to frequency deviations,
- Reserves, which include Contingency (Primary) Reserve (combination of Synchronized and Non-Synchronized Reserves), and Secondary Reserve,
- Black Start Service, which include generating units that can start and synchronize to the system without having an outside (system) source of AC power, and
- Reactive Services, which help maintain transmission voltages within acceptable limits.

Statistical analysis of wind, PV and load data was employed to determine how much additional regulation capacity would be required to manage renewable variability in each of the study scenarios. The regulation requirement for wind and solar was combined with the regulation requirement for load (a percentage of peak or valley load MW, per PJM rules) to calculate a total regulation requirement.

The analysis illustrated that the variability of wind and solar power output is a function of the total production level (see Figure 6). More regulation is needed when production is at mid-level, and less regulating reserves are needed when production is very low or very high. Previous studies have established that a statistically high level of confidence for reserve is achieved at about 3 standard deviations (or 3σ in industry parlance) of 10-minute renewable variability. The 3σ criterion was also adopted for this study, which means that the regulation requirements are designed to cover 99.7% of all 10-minute variations. Table 3 summarizes the range of regulation required for each scenario. In the production cost and sub-hourly simulations, the amount of regulation was adjusted hourly as a function of the total renewable energy production in each hour.

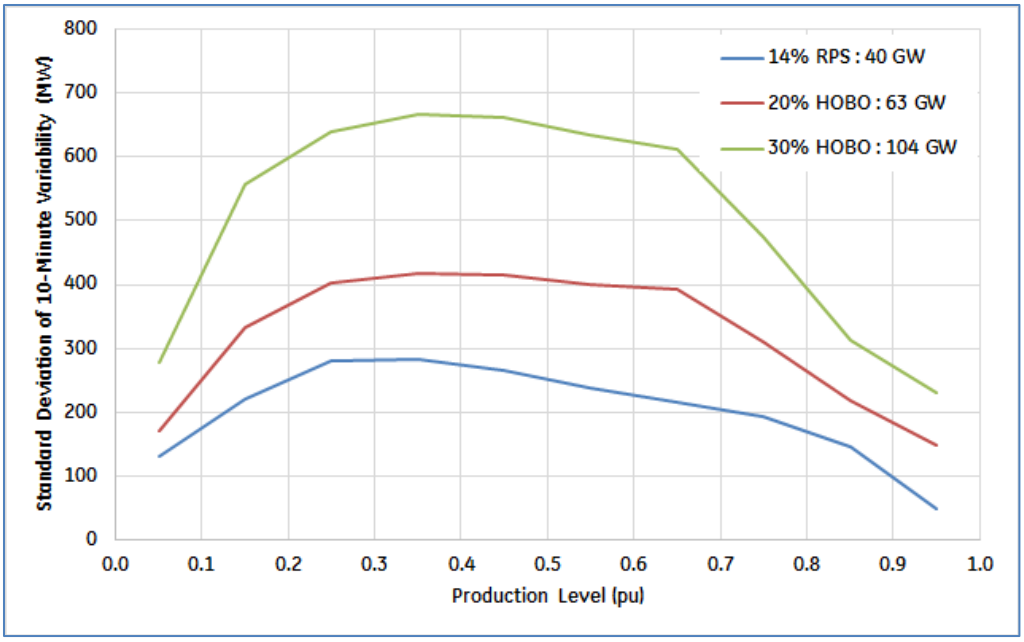

Figure 6: Ten-Minute Variability in Wind and Solar Output as a Function of Production Level

Table 3: Estimated Regulation Requirements for Study Scenarios

Regulation	Load Only	2% BAU	14% RPS	20% HOBO	20% LOBO	20% LODO	20% HSBO	30% HOBO	30% LOBO	30% LODO	30% HSBO
Maximum (MW)	2,003	2,018	2,351	2,507	2,721	2,591	2,984	3,044	3,552	3,191	4,111
Minimum (MW)	745	766	919	966	1,031	1,052	976	1,188	1,103	1,299	1,069
Average (MW)	1,204	1,222	1,566	1,715	1,894	1,784	1,958	2,169	2,504	2,286	2,737
% Increase Compared to Load		1.5%	30.1%	42.4%	57.3%	48.2%	62.6%	80.2%	108.0%	89.8%	127.4%

From a contingency perspective, none of the wind or solar plants added to the PJM system was large enough such that their loss would increase PJM's present level of contingency reserves. And given the large PJM footprint for a single balancing area, the impacts of short-term variability in wind and solar production is greatly reduced by aggregation and geographic diversity.

The following approach was adopted to assess the need for additional ancillary services due to wind and solar variability:

- Simulate hourly operation using GE MAPS, with regulation allocated per the criteria described above and contingency reserves per PJM's present practices.

- Using the hourly results of the GE MAPS simulations, compare the ramping capability of the committed units each hour with the sub-hourly variability of wind and solar production in that hour.
- Quantify the number of periods where ramping capability is insufficient.

Figure 7 is an excerpt from the ramp analysis, showing a day with three 10-minute periods when the change in net load (red dots) exceed the ramp-up capability of the committed generators (green line). Table 4 summarizes the analytical results for several scenarios, and shows that there are relatively few periods in a year when renewable ramps exceed fleet ramping capability, and those few events would not likely cause an unacceptable decrease in PJM's Control Performance Standard (CPS) measures.

The adequacy of the regulation was further confirmed by the challenging days simulated in the PROBE sub-hourly analysis. The selection criteria specifically included days with low ramp-rate and ramp-range capability relative to wind and solar ramps.

The results of the combined analytical methods indicate that no additional operating reserves would be required for the study scenarios.

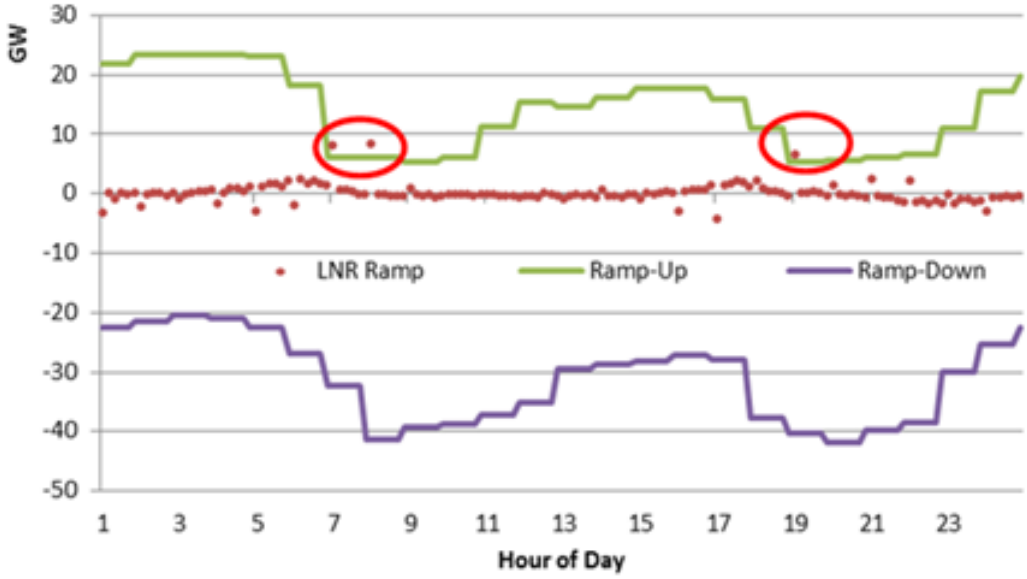

Figure 7: Sample Day Showing 10-Minute Periods that Exceeded Ramp Capability

Table 4: Ten-minute Periods Exceeding Ramp Capability for Selected Scenarios

52,560 Samples	2% BAU		14% RPS		30% HOBO		30% LODO	
Number of 10-Min samples exceeding dispatched ramp capability	Count	%	Count	%	Count	%	Count	%
Ramp-up	25	0.048%	32	0.061%	322	0.613%	19	0.036%
Ramp-down	0	0.000%	0	0.000%	5	0.010%	57	0.108%

7 Transmission System Upgrades

The transmission model was built upon the 2016 and 2017 Regional Transmission Expansion Plan (RTEP) models provided by PJM. New lines and other transmission upgrades were added to the transmission models for each study scenario to serve the increased load and generation resources. Given that the output of wind and solar resources inherently varies by time of day and season of year, the traditional transmission expansion planning methods were augmented by production cost analysis to ensure adequate transmission capacity without overbuilding. Some wind plants and thermal plants share common transmission corridors, and since wind plants are not dispatchable, it is not appropriate to size those corridors to accommodate simultaneous maximum output from both wind and thermal plants.

The transmission expansion process involved the following steps:

- Security-constrained optimal power flow analysis to identify transmission paths that are overloaded under contingency conditions and cannot be relieved by adjusting the dispatch.
- Generator deliverability analysis with wind and solar plant loaded to 100% of capacity value, to identify reliability problems that required transmission upgrades.
- Generator deliverability analysis with wind and solar plant loaded to 100% of energy value, to identify flowgates that could be overloaded and therefore should be monitored in production cost analysis.
- Production cost analysis to quantify annual transmission path utilization and congestion, and to identify paths with excessive congestion.

These steps were performed iteratively on each scenario to design a set of transmission upgrades that would achieve deliverability and reliability objectives while limiting congestion to a reasonable level. This was achieved by increasing transmission capacity until the largest contribution to congestion costs by a constrained element between two nodes with highest and lowest average annual LMP in the system was $5/MWh, averaged across the year.

Table 5 summarizes the transmission additions and upgrades for each scenario. New lines indicate new line construction on new or existing right-of-ways. Upgrades involve improvements to existing lines (i.e., reconductoring to increase current rating).

Table 5: New Lines and Transmission Upgrades for Study Scenarios

Scenario	765 kV New Lines (Miles)	765 kV Upgrades (Miles)	500 kV New Lines (Miles)	500 kV Upgrades (Miles)	345 kV New Lines (Miles)	345 kV Upgrades (Miles)	230 kV New Lines (Miles)	230 kV Upgrades (Miles)	Total (Miles)	Total Cost (Billion)	Total Congestion Cost (Billion)
2% BAU	0	0	0	0	0	0	0	0	0	$0	$1.9
14% RPS	260	0	42	61	352	35	0	4	754	$3.7	$4.0
20% Low Offshore Best Onshore	260	0	42	61	416	122	0	4	905	$4.1	$4.0
20% Low Offshore Dispersed Onshore	260	0	42	61	373	35	0	49	820	$3.8	$4.9
20% High Offshore Best Onshore	260	0	112	61	363	122	17	4	939	$4.4	$4.3
20% High Solar Best Onshore	260	0	42	61	365	122	0	4	854	$3.9	$3.3
30% Low Offshore Best Onshore	1800	0	42	61	796	129	44	74	2946	$13.7	$5.2
30% Low Offshore Dispersed Onshore	430	0	42	61	384	166	44	55	1182	$5.0	$6.3
30% High Offshore Best Onshore	1220	0	223	105	424	35	14	29	2050	$10.9	$5.3
30% High Solar Best Onshore	1090	0	42	61	386	122	4	4	1709	$8	$5.6

8 Impact of Renewables on Annual PJM Operations

Hourly annual operation for all study scenarios was simulated using the GE Multi-Area Production Simulation (GE MAPS) model. GE MAPS model employs Security-Constrained Unit Commitment (SCUC) and Security-Constrained Economic Dispatch (SCED) to emulate the hourly operation of a competitive market and models the full transmission system to account for congestion. The results show the following impacts of higher wind and solar energy penetration on the PJM grid:

- Lower Coal and CCGT generation under all scenarios. Wind and solar resources are effectively price-takers and therefore displace more expensive generation resources.
- Lower emissions of criteria pollutants and greenhouse gases, due to reduced operation of thermal generation resources.

- No unserved load and minimal renewable energy curtailment. New thermal resources were added to meet reserve requirements for the 2% BAU case in 2026, and those resources were kept available for all higher renewable penetration scenarios. This is a contributing factor in the result that in all scenarios there were adequate reserves and no instances of unserved load[7]. There were no operating conditions where wind/solar variability or uncertainty caused an insufficiency of generation. Nearly all of the wind and solar energy was used to serve load.
- Lower system-wide production costs (i.e., fuel and O&M costs for thermal generators)
- Lower gross revenues for conventional generation resources
- Lower average LMP and zonal prices across the PJM grid

Figure 8 illustrates how the energy dispatch shifts from gas and coal generation to renewable resources as the renewable penetration increases. The upper plot shows the progression to 20% penetration and the lower plot extends to 30% penetration of wind and solar energy. On average for all scenarios, about 36% of the renewable energy displaces coal-based generation about 39% displaces gas-fired generation, as compared to the 2% BAU Scenario.

[7] If the study plan had assumed constant installed reserve margins across all study scenarios, there would likely have been more instances of unserved load or demand response calls in the higher penetration scenarios.

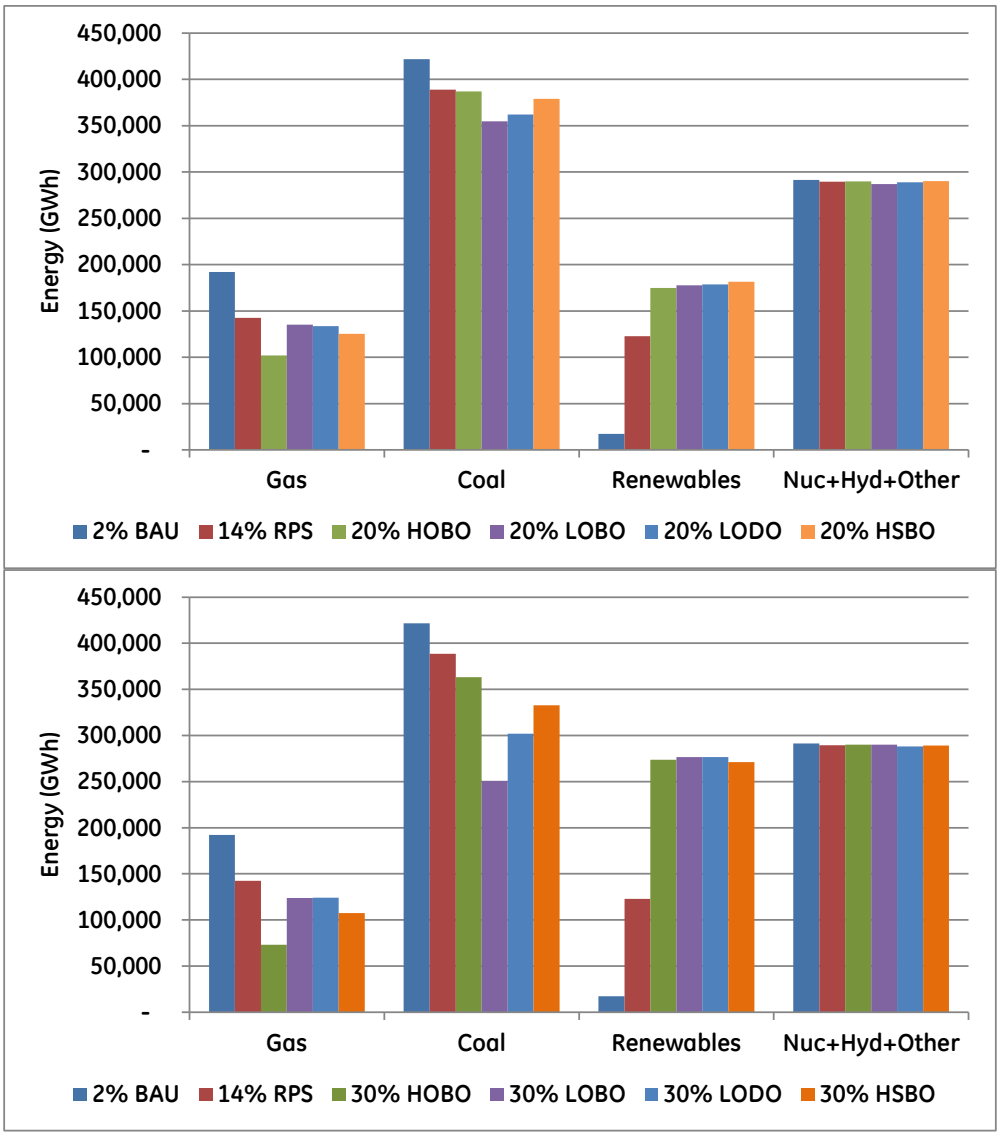

Figure 8: Annual Energy Production by Unit Type for Study Scenarios

Table 6 shows how several economic and energy parameters are affected by increased renewables in the study scenarios. Changes are measured relative to the 2% BAU scenario. In the 14% RPS scenario, 47% of the additional renewable energy displaces gas-fired resources and 31% displaces coal. In several of the 20% and 30% scenarios, proportionately more coal energy is displaced.

Table 6: Annual Production Cost and Energy Displacement by Unit Type for Study Scenarios

Scenario	Renewable Energy Delivered (GWh)	Production Cost ($B)	Wholesale Load Payments Delta ($B)	Gas Delta (GWh)	Coal Delta (GWh)	Imports Delta (GWh)	Gas Displacement (%)	Coal Displacement (%)	Reduced Imports (%)
2% BAU	17,217	40.5	71.8	192,025	421,618	47,390	0%	0%	0%
	Delta Relative to 2% BAU Scenario								
14% RPS	105,642	-6.8	-4.2	-49,590	-32,866	-21,397	-47%	-31%	-20%
20% HOBO	157,552	-10.6	-21.5	-90,194	-34,604	-31,302	-57%	-22%	-20%
20% LOBO	160,490	-9.9	-10.1	-56,854	-66,940	-32,267	-35%	-42%	-20%
20% LODO	161,542	-10.1	-8.6	-58,322	-59,647	-41,085	-36%	-37%	-25%
20% HSBO	164,253	-12.1	-12.7	-66,682	-42,505	-53,696	-41%	-26%	-33%
30% HOBO	256,400	-16.1	-21.5	-118,876	-58,453	-77,631	-46%	-23%	-30%
30% LOBO	259,428	-14.8	-10.1	-68,192	-170,920	-19,134	-26%	-66%	-7%
30% LODO	259,345	-15.1	-8.6	-68,013	-119,526	-68,653	-26%	-46%	-26%
30% HSBO	253,918	-15.6	-15.3	-84,511	-88,847	-78,382	-33%	-35%	-31%
Average							-39%	-36%	-24%

Production Cost is sum of Fuel Costs, Variable O&M Costs, any Emission Tax/Allowance Costs, and Start-Up Costs – adjusted by adding Imports Costs and subtracting Export Sales.

Coal, Gas, and Import Displacement values are the ratio of GWh reductions in each energy resource (Coal, Gas, Imports) relative to the GWh increase in Total Renewable Energy Delivered.

This study did not evaluate potential impacts on the PJM Capacity Market due to reduced generator revenues from the wholesale energy market, nor did it evaluate the impact of renewables on rate payers. It is conceivable that lower energy prices would be at least partially offset by higher capacity prices.

Figure 9 shows several annual operational trends for the study scenarios. Compared to the 2% BAU scenario,

- Coal and CCGT capacity factors decline with increasing renewables
- CCGT annual starts remain the same for the 14% RPS scenario and double for many of the 20% and 30% scenarios, indicating an increase in cycling duty. Annual starts for coal plants increase slightly, indicating that there are periods of the year when some coal plants are not committed.
- Net energy revenues for CCGT and coal plants decline significantly with increasing renewables, potentially leading to additional generator retirements. This study did

not look at revenue adequacy, potential retirements, or the cost to maintain resource adequacy.

- Most of the new renewable energy is used to serve load and only a small portion must be curtailed in the 20% and 30% scenarios, mostly due to local congestion.

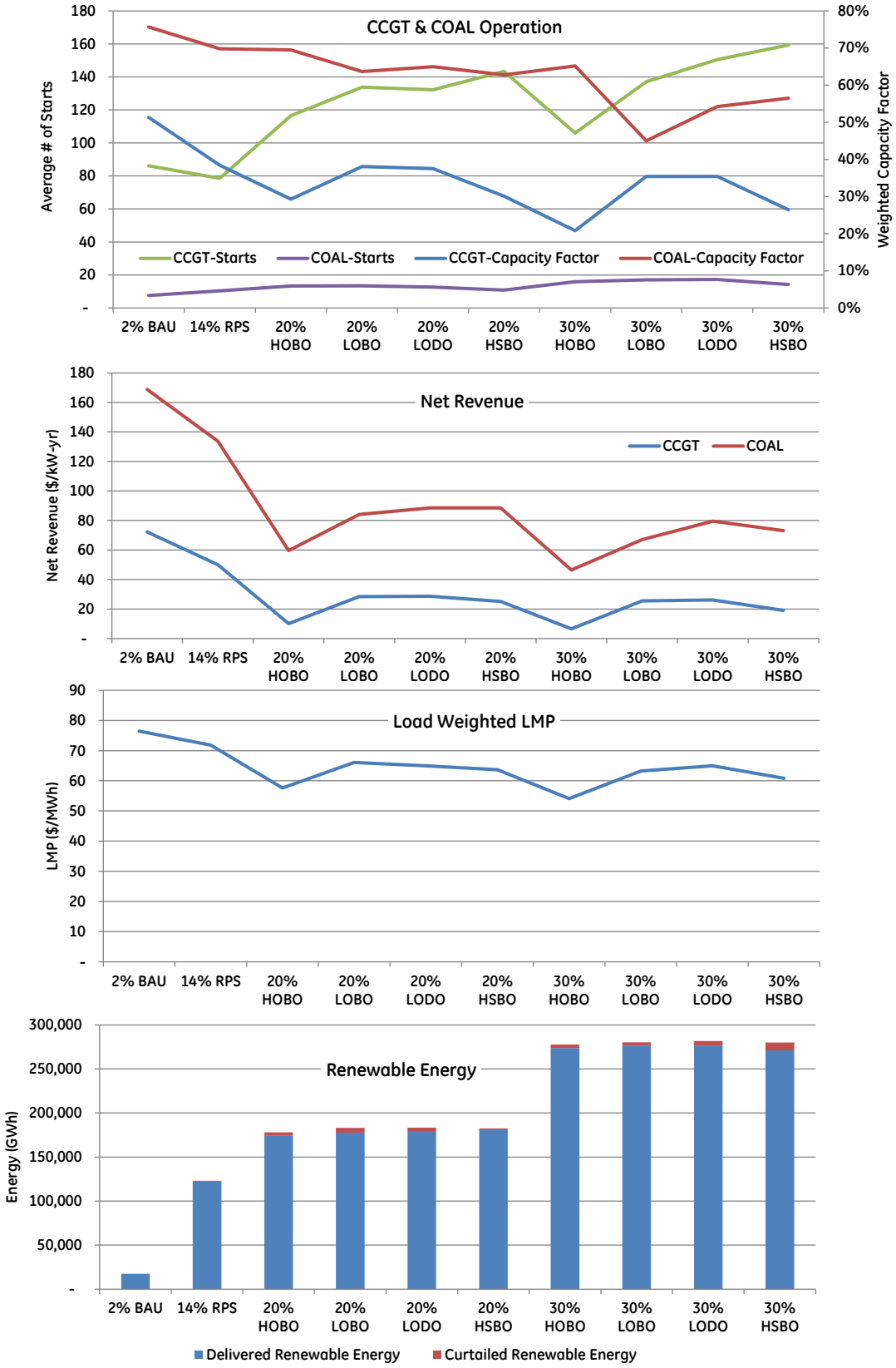

Figure 9: PJM Annual Operation Trends for Study Scenarios

Figure 10 shows trends in total PJM production costs and transmission expansion/upgrade costs as a function of renewable penetration level. Production costs are fairly similar for all scenarios with the same renewable energy penetration. Estimated transmission costs are similar for all 20% penetration scenarios but dramatically different for the 30% scenarios. The 30% LOBO scenario includes a high concentration of wind power in the western PJM region, and significant transmission upgrades are needed to transport that wind energy to load centers. In the LODO scenario, wind resources are more dispersed across the PJM footprint, so the wind plants are closer to load centers.

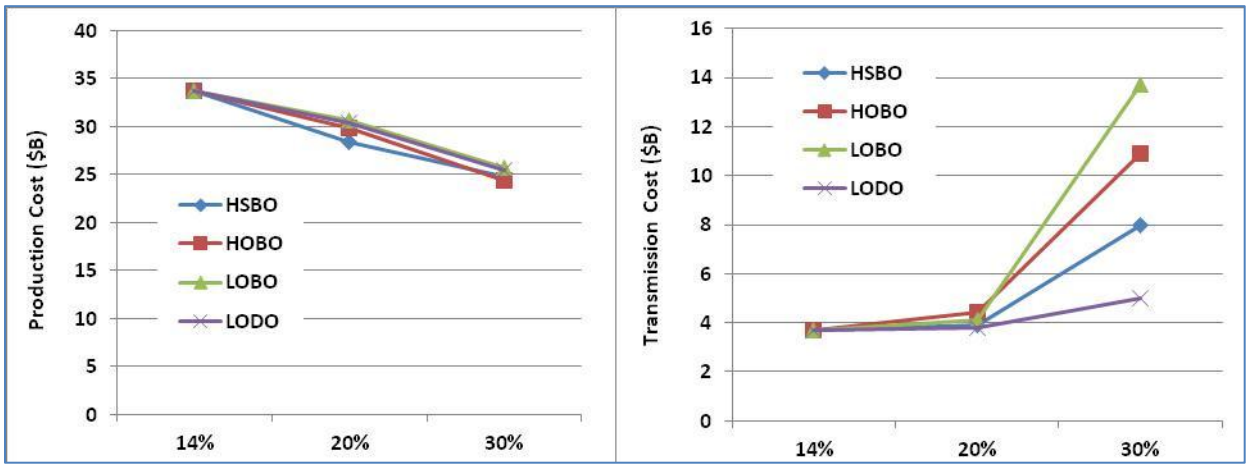

Figure 10: Trends in Production Costs and Transmission Costs versus Renewable Penetration

Table 7 shows the impact of renewable energy in production cost savings in each of the study scenarios. The value is calculated as the reduction in PJM annual production cost divided by the increase in delivered renewable energy, relative to the 2% BAU scenario. The right-hand column shows the production cost savings of the renewables adjusted for the estimated annualized cost of transmission upgrades. The range of production cost savings due to renewable energy ranges from $56 to $74 per MWh of Renewable Energy based on production costs alone, and $49 to $71 per MWh of Renewable Energy if estimated costs for transmission upgrades are included. As noted before, Production Cost is sum of Fuel Costs, Variable O&M Costs, any Emission Tax/Allowance Costs, and Start-Up Costs – adjusted by adding Imports Costs and subtracting Export Sales. A carrying charge of 15% was used to calculate the annualized transmission cost from total estimated capital costs.

Table 7: Renewable Contribution to Lowering Production Cost

Scenario	Renewable Energy Delivered (GWh) over the 2% BAU Scenario (GWh)	Production Cost Savings over the 2% BAU Scenario ($B/Year)	Production Cost Savings per MWh of Delivered Renewables ($/MWh RE)	Annualized Transmission Costs ($M/Year)	Transmission Costs per MWh of Delivered Renewables ($/MWh RE)	Production Cost Savings Adjusted for Transmission Costs ($/MWh RE)
14% RPS	105,642	-6.8	63.9	555	4.5	59.4
20% HOBO	157,552	-10.6	67.4	660	3.8	63.7
20% LOBO	160,490	-9.9	61.4	615	3.5	58.0
20% LODO	161,542	-10.1	62.6	570	3.2	59.4
20% HSBO	164,253	-12.1	73.8	585	3.2	70.6
30% HOBO	256,400	-16.1	62.7	1,635	6.0	56.8
30% LOBO	259,428	-14.8	56.9	2,055	7.4	49.5
30% LODO	259,345	-15.1	58.1	750	2.7	55.4
30% HSBO	253,918	-15.6	61.6	1,200	4.4	57.2

9 Sub-Hourly Operations and Real-Time Market

Sub-hourly analysis was performed to augment the hourly production cost simulations, to check if committed resources and reserves could keep up with short-term changes in load and renewables in real-time operations. The analysis explored:

- Adequacy of reserves
- Commitment/dispatch of quick-start CTs to follow rapid changes in net load
- Ramping capability and performance of dispatchable units
- Impact of day-ahead forecast errors and forward-market commitments
- Potential for unserved load
- Ability of the system to respond to fast-moving events

The analysis was performed using PowerGEM's PROBE simulation software, which is presently used by PJM to monitor daily performance of the real-time market. The approach involves identifying several challenging days for each scenario; that is, days with rapid changes in renewable output or other situations that would present difficulties for real-time operations. If the system performs successfully during the challenging days, then other less-challenging days would have acceptable performance as well. The screening criteria included:

- Largest 10-minute ramp in Load-Net-Renewable (LNR)
- Largest daily range in LNR (maximum LNR – minimum LNR for the day)

- Largest 10-minute ramp up or down deviations relative to the ramp capability of committed units
- High volatility day, with largest number of 10-minute periods where the change in net load (LNR) exceeded the range capability of committed units

In general, all the simulations of challenging days revealed successful operation of the PJM real-time market. Although there were occasionally periods of reserve shortfalls and new patterns of CT usage, there were no instances of unserved load.

The level of difficulty for real-time operations largely depends on the day-ahead unit commitment, which in turn depends on the day-ahead forecast for load, wind and solar. On days when the day-ahead commitment was significantly lower than the actual net load to be served in the real-time market - most commonly due to an over-forecast of wind and solar energy - additional CT generation resources were committed in real-time. The modeled installed CT capacity in PJM in 2026 is about 65 GW and these units were able to compensate for forecast errors and fast-moving events even on the most challenging days investigated in this study.

Higher penetrations of renewable energy (20% and 30%) create operational patterns that are significantly different than what is common today, especially with respect to CT usage. Figure 11 shows the CT usage for a summer-peak day in the 2% BAU scenario. It shows that about 56 GWs of CTs were committed in the day-ahead market (blue region) to meet the anticipated peak load during the mid-day hours. About 3 GWs of additional CTs were committed in the real-time market (red region) to make up for relatively minor forecast errors on that day. At the peak, there were still about 1 GWs of CTs available to respond to other unanticipated events.

Figure 12 shows a plot of CT usage for February 17 in the 30% LOBO scenario. The blue trace is total system demand, the red trace is total renewable generation, and the green symbols show the number of committed CTs. Figure 13 shows the March 4 PJM average LMP for several 20% and 30% scenarios. The price peaks around 8 am and 6 pm indicate increased commitment of CTs to compensate for short-term changes in load and renewables. These plots illustrate trends observed in many of the high renewable scenarios, where CT's are used less during peak load periods and more during periods where there are rapid changes in load, wind, and solar (particularly during the beginning and end of the solar day, when solar power output ramps up or down) or to compensate for errors in the day-ahead renewable energy forecast.

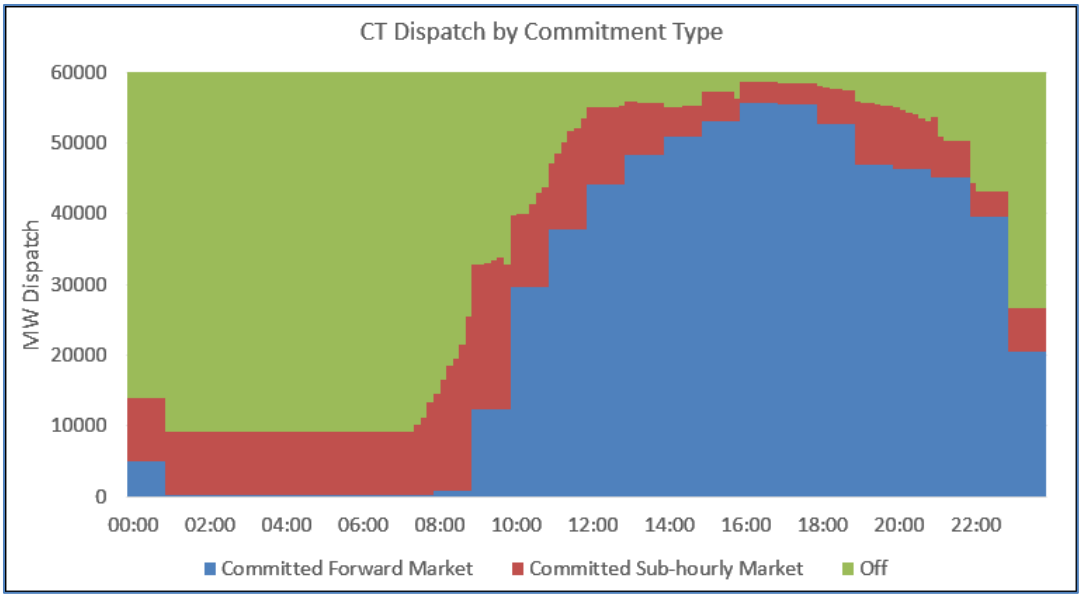

Figure 11: CT Capacity Committed (2% BAU, July 28)

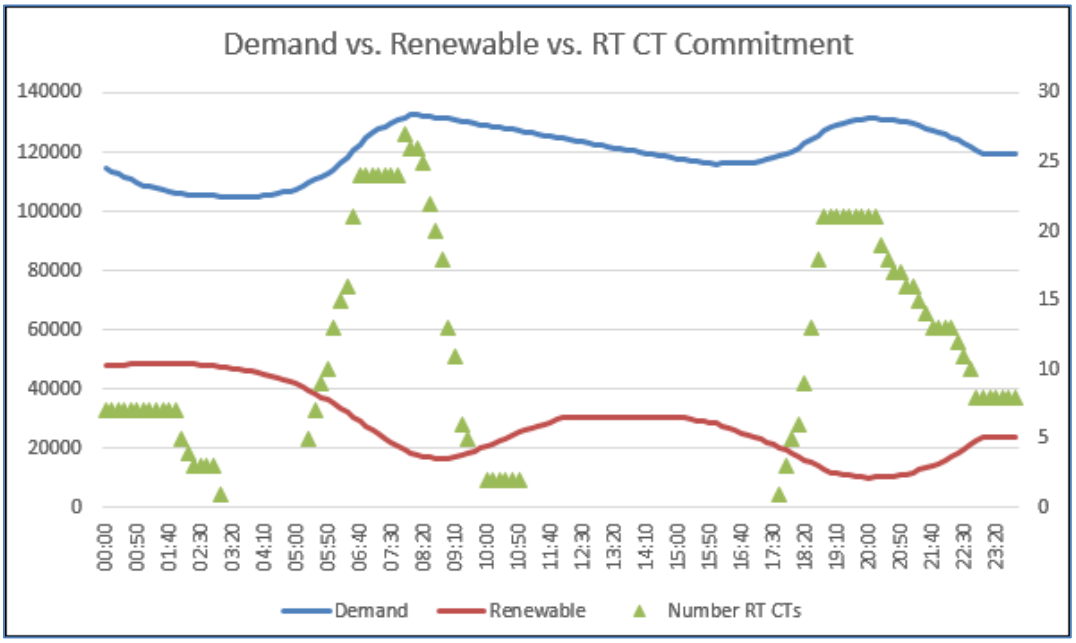

Figure 12: Demand MW, Renewable Dispatch, and # of CTs Committed in RT (30% LOBO, February 17)

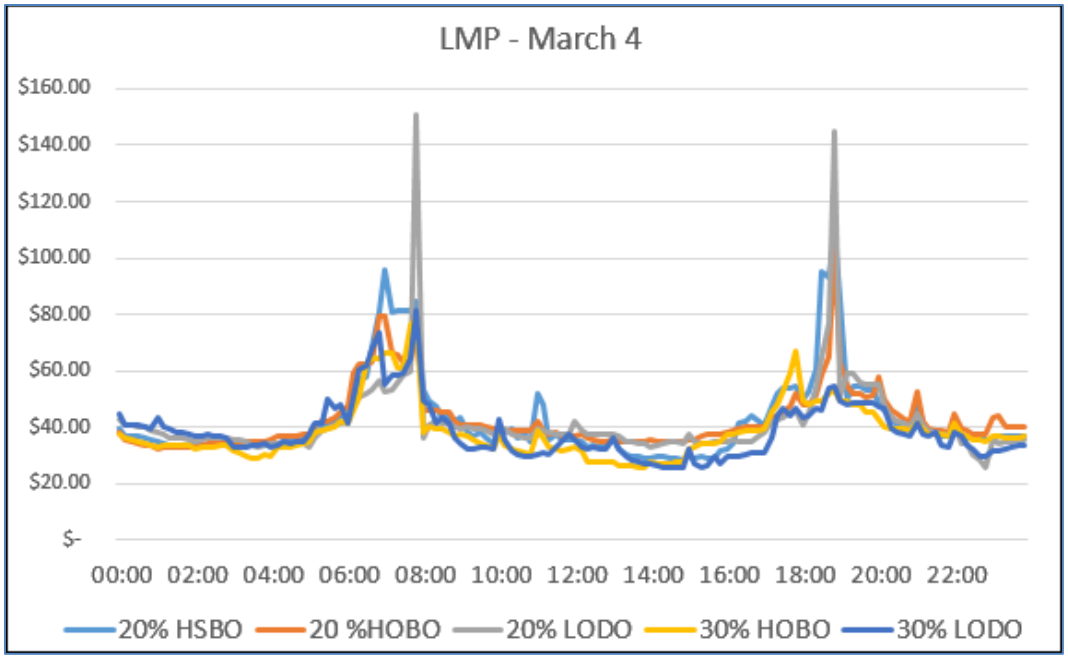

Figure 13: LMP Comparison for Several 20% and 30% Scenarios (March 4)

10 Capacity Value of Wind and Solar Resources

The reliability of a power system is governed by having sufficient generation capacity to meet the load at all times. There are several types of randomly occurring events, such as generator forced outages, unexpected de-ratings, etc., which must be taken into consideration during the planning stage to ensure sufficient generation capacity is available. Since the rated MW of installed generation may not be available at all times, due to the factors described above, the effective capacity value of generation is normally lower than 100% of its rated capacity. This effect becomes more pronounced for variable and intermittent resources, such as wind and solar PV. As an example, a 100 MW gas turbine will typically have a capacity value of approximately 95 MW, while a 100 MW wind plant may only have a capacity value of approximately 15 MW. It is therefore important to characterize the capacity value of such resources so that grid planners can ensure sufficient reserve margin or generation capacity is available at all times under a projected load growth scenario.

This report presents the analysis on the capacity value of wind and solar resources in different scenarios considered in the study. The analysis was conducted using GE Multi-Area Reliability Simulation (GE MARS) Software, and the capacity value was measured in terms of "Effective Load Carrying Capability" (ELCC). The ELCC of a resource is defined as the increase in peak load that will give the same system reliability as the original system without the resource. Figure 14 shows that the addition of a block of renewables allowed the peak load to increase by

30,000 MW in order to bring the system reliability back to the original design criteria of 0.1 days/year.

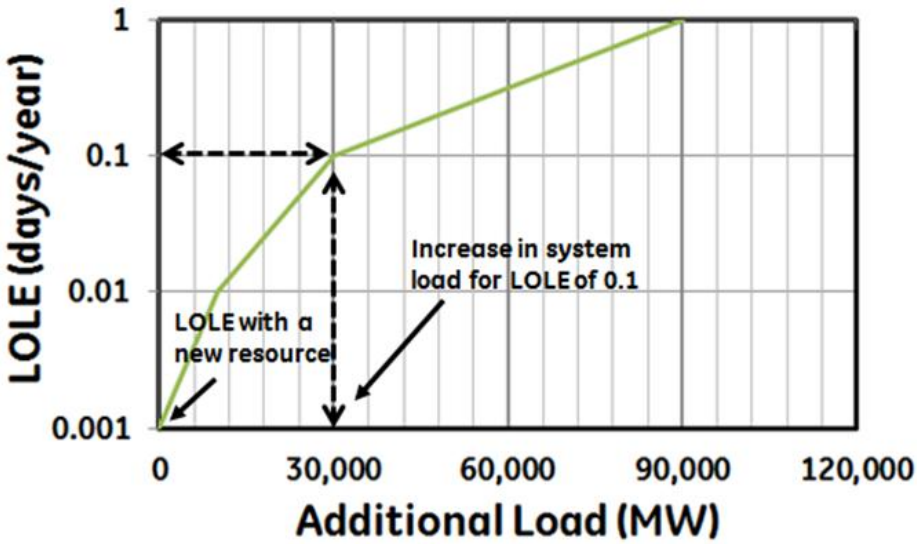

Figure 14: Effective Load Carrying Capability of a Resource

If this was for the addition of 100,000 MW of renewable capacity, the average ELCC would be 30% (i.e., 30,000 / 100,000). These values were determined for each renewable generation type over the range of penetration scenarios considered.

PJM Manual 21 defines the current procedures for estimating the capacity value of intermittent resources, such as wind and solar PV generators. The manual defines the capacity value of the intermittent resource (in percentage terms) as the average capacity factor that the resources have exhibited in the last three years during the Summer Peak Hours[8]. Table 8 compares the range of ELCC values to those determined using the PJM Manual 21 methodology. These values can be compared since they were based on the same hourly generation profiles.

[8] Summer Peak Hours are those hours ending 3, 4, 5, and 6 PM Local Prevailing Time on days from June 1 through August 31, inclusive.

Table 8: Range of Effective Load Carrying Capability (ELCC) for Wind and Solar Resources in 20% and 30% Scenarios

Resource	ELCC (%)	PJM Manual 21 (Summer Peak Hour Average Capacity Factor)
Residential PV	57% - 58%	51%
Commercial PV	55% - 56%	49%
Central PV	62% - 66%	62% - 63%
Off-shore Wind	21% - 29%	31% - 34%
Onshore Wind	14% - 18%	24% - 26%

These values are larger than the current class averages of 13% for wind and 38% for solar which were based on actual historical values. This is because the profiles were developed at optimum sites using the most current power conversion technologies. It was felt that these would provide a better estimate of the likely capacity values of the renewable plants in the future. Individual plants will continue to have their capacity values based on their actual performance and it is expected that the plants with newer technology will have higher values than existing ones.

11 Impact of Cycling Duty on Variable O&M Costs

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. Figure 15 illustrates several types of cycling events that cause fatigue damage, with cold starts having the greatest impact.

The following technical approach was used to quantify the variable O&M (VOM) costs due to cycling for the various study scenarios:

- Characterize past cycling duty by examining historical operations data for the major types of thermal units in the PJM fleet; supercritical coal, subcritical coal, gas-fired combined cycle, large and small gas-fired combustion turbines[9].

[9] Nuclear and hydro units were not evaluated since nuclear units operate at constant load and hydro units do not experience thermal fatigue damage from cycling.

- Quantify O&M costs for those levels of cycling duty based on Intertek AIM's O&M/cycling database for a large sample of similar types of units.
- Establish baseline of cycling O&M costs by unit type for the 2% BAU scenario.
- Calculate changes to cycling duty and O&M costs for new operational patterns in each of the study scenarios from annual production cost simulation results.

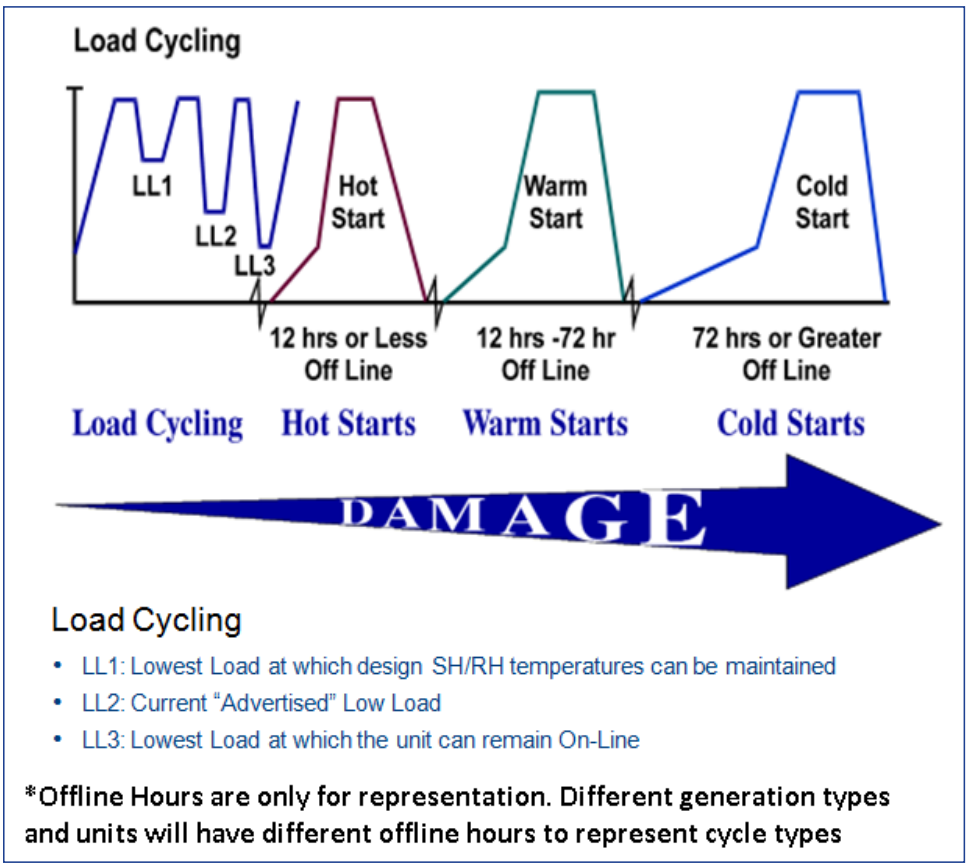

Figure 15: Types of Cycling Duty That Affect Cycling Costs

Figure 16 summarizes changes in cycling duty by study scenario for five types of PJM units. Combined cycle units experience the largest change in cycling duty as renewable penetration increases. Some increase in cycling is also evident for supercritical coal units in the 30% scenarios. Combined cycle units perform majority of the on/off cycling in the scenarios, with the coal units performing much of the load follow cycling.

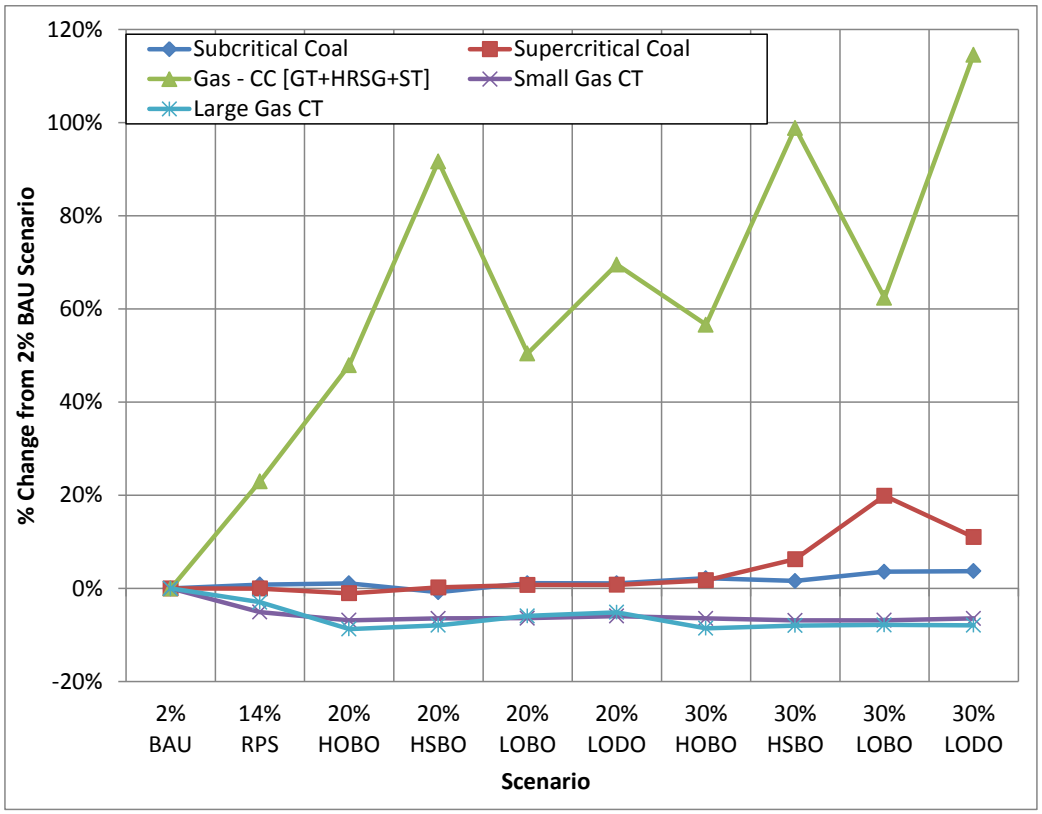

Figure 16: Net Effect on Cycling Damage Compared to 2% BAU Scenario

Table 9 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 9: 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

Figure 17 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.

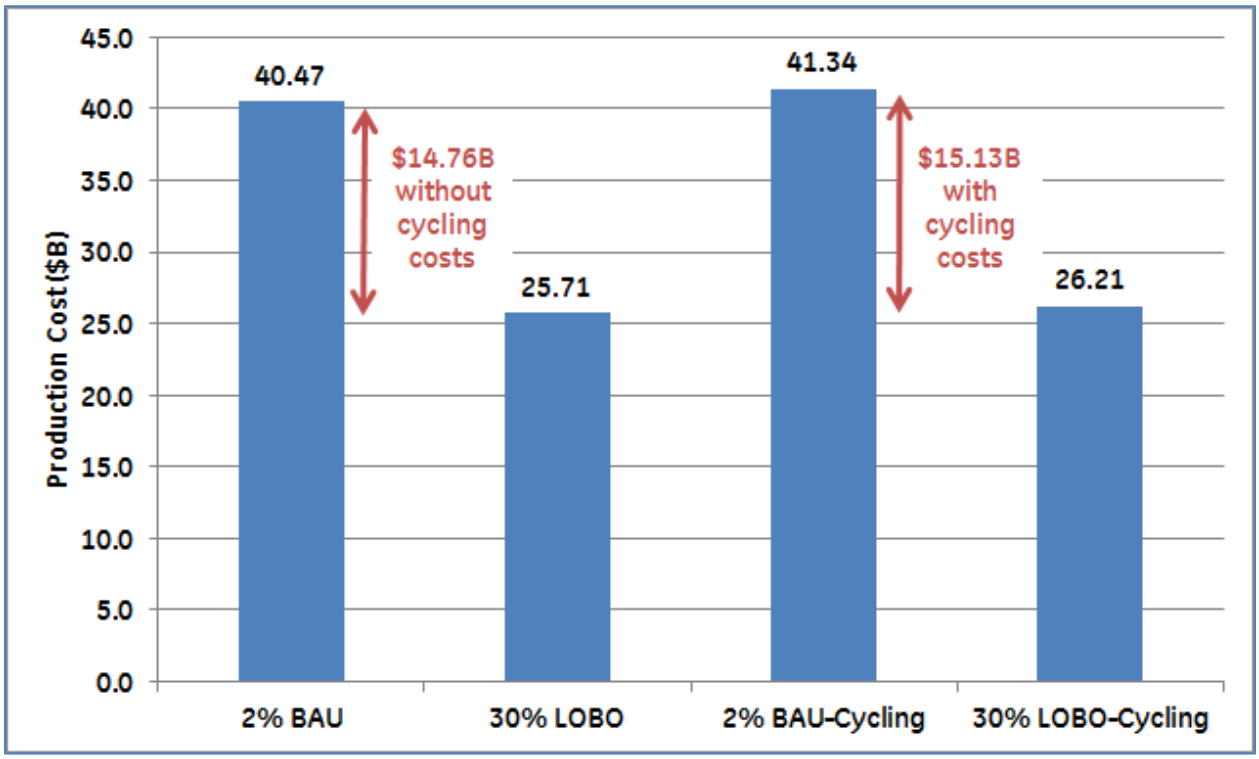

Figure 17: Impact of Cycling Effects on Total Production Costs for 2% BAU and 30% LOBO Scenarios

12 Power Plant Emissions

Variability of renewable energy resources requires the coal and gas fired generation resources to adapt with less efficient ramping and cycling operations, which in turn impacts their environmental emissions. This study examined the changes in emissions amounts and rates for the PJM portfolio for each of the study scenarios which differ in the level of cycling operations of the units.

Actual historical power plant emissions were analyzed to derive the impact of plant cycling on each type of power plant. Regression analysis was used to quantify the changes in plant emissions during ramps in plant output, when plant emission controls are often unable to keep emission rates as low as during steady-state operation.

GE MAPS production cost simulations were used to calculate the steady state "without cycling" emission amounts, which were then updated using Intertek AIM's regression results to generate the total "with cycling" emissions estimates.

Total Emissions = Steady State Emissions (from GE MAPS)
+ Extra Cycling-Related Emissions (from Intertek AIM Regression Model)

Figure 18 and Figure 19 show the overall results of the emissions analysis. In Figure 18, the dark blue bars show steady-state SOx emissions as calculated by the production cost simulations. The dark red bars stacked over the dark blue bars show incremental SOx emissions due to unit cycling. In Figure 19, the green and orange bars show similar results for NOx emissions. The black lines show total generation energy from the thermal power plants. The results indicate that SOx and NOx emissions decline as renewable penetration increases, but increased cycling causes the reduction to be somewhat smaller than would be calculated by simply considering a constant emission rate per MMBtu of energy consumed at gas and coal generation facilities. Table 10 presents similar results for CO2 emissions.

The overall results of the emissions analysis show that:

- Emissions from coal plants comprise 97% of the NOx and 99% of the SOx emissions.
- For scenarios that experience increased emissions due to cycling, the increases are dominated by supercritical coal emissions.
- NOx and SOx rates (lbs./MMBtu) increase at low loads for coal plants and decrease for CTs.
- Load-follow cycling is the primary contributor of cycling related emissions.

- Including the effects of cycling in emissions calculations does not significantly change the level of emissions for scenarios with higher levels of renewable generation. However, on/off cycling and load-following ramps do increase emissions over steady state levels. This analysis has provided quantified data on the magnitudes of those impacts.

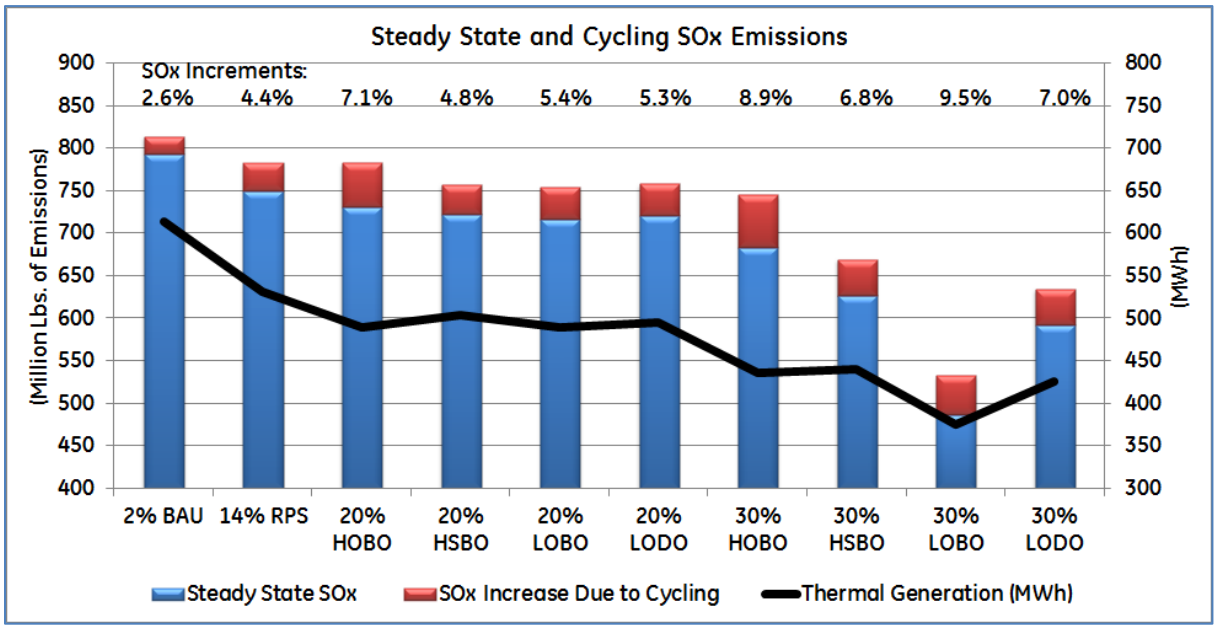

Figure 18: SOx Emissions for Study Scenarios, With and Without Cycling Effects Included

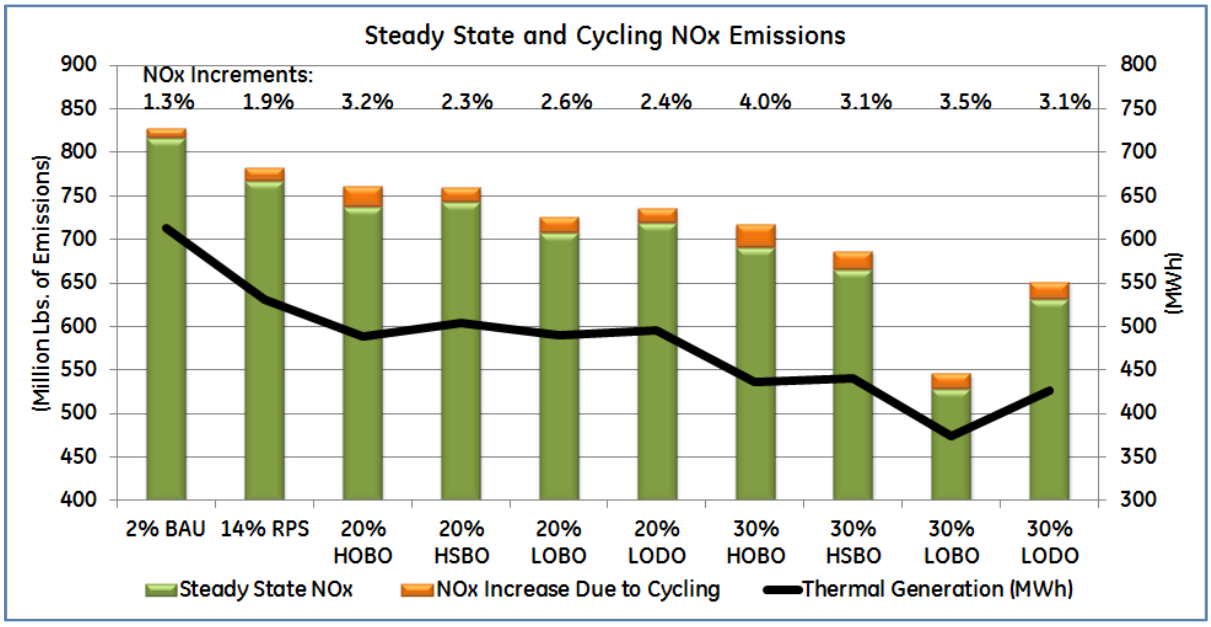

Figure 19: NOx Emissions for Study Scenarios, With and Without Cycling Effects Included

Table 10: CO2 Emissions from PJM Power Plants for Study Scenarios

Scenario	Reduction in MWh Energy Output from Coal and Gas Plants Relative to 2% BAU Scenario	Reduction in Heat Input (Fuel) Relative to 2% BAU Scenario	Reduction in CO2 Emissions Relative to 2% BAU Scenario
14% RPS	15%	14%	12%
20% HOBO	20%	18%	14%
20% HSBO	18%	16%	15%
20% LOBO	19%	19%	18%
20% LODO	18%	18%	17%
30% HOBO	35%	32%	27%
30% HSBO	31%	29%	28%
30% LOBO	40%	40%	41%
30% LODO	30%	29%	29%

13 Sensitivities to Changes in Study Assumptions

The following sensitivities were investigated using production cost simulations:

LL Low Load Growth: 6.1% reduction in demand energy compared to the base case

LG Low Natural Gas Price: AEO forecast of $6.50/MMBtu compared to $8.02/MMBtu in the base case

LL, LG Low Load Growth & Low Natural Gas Price

LG, C Low Natural Gas Price & High Carbon Cost: Carbon Cost $40/Ton compared to $0/Ton in the base case

PF Perfect Wind & Solar forecast: Perfect knowledge of the wind and solar for commitment and dispatch, which provides a benchmark of the maximum possible benefit from forecast improvements.

The analysis was performed on the 2% BAU, 14% RPS, 20% LOBO and 30% LOBO scenarios. Table 11, Table 12, and Table 13 show overall PJM production cost, generation revenue, load cost, and load-weighted LMP for the 14% RPS, 20% LOBO, and 30% LOBO scenarios. Figure 20 shows representative results for the 20% LOBO scenario, focusing on annual energy production by unit type and total system emissions.

Table 11: Sensitivity Analysis Results for 2% BAU Scenario

PJM Sensitivities	2% BAU	2% BAU (LL)	2% BAU (LL, LG)	2% BAU (LG)	2% BAU (LG, C)	2% BAU (PF)
Production Costs ($M)	40,470	36,099	34,370	38,341	59,763	40,462
Change from Base	0	-4,372	-6,100	-2,129	19,292	-8
Relative Change	0.00%	-12.11%	-17.75%	-5.55%	32.28%	-0.02%
Generator Revenue ($M)	70,023	61,057	53,826	62,263	93,352	70,182
Change from Base	0	-8,966	-16,197	-7,760	23,328	158
Relative Change	0.00%	-14.68%	-30.09%	-12.46%	24.99%	0.23%
Costs to Load ($M)	70,947	62,358	57,036	65,814	100,545	71,795
Change from Base	0	-8,589	-13,911	-5,133	29,597	848
Relative Change	0.00%	-13.77%	-24.39%	-7.80%	29.44%	1.18%
Load Wtd LMP ($/MWh)	76.5	71.8	65.7	70.9	108.4	77.4
Change from Base	0.0	-4.7	-10.8	-5.5	31.9	0.9
Relative Change	0.00%	-6.51%	-16.45%	-7.79%	29.44%	1.18%

Table 12: Sensitivity Analysis Results for 14% RPS Scenario

PJM Sensitivities	14% RPS	14% RPS (LL)	14% RPS (LL, LG)	14% RPS (LG)	14% RPS (LG, C)	14% RPS (PF)
Production Costs ($M)	33,719	29,791	28,482	32,102	50,380	33,470
Change from Base	0	-3,928	-5,237	-1,617	16,660	-250
Relative Change	0.00%	-13.19%	-18.39%	-5.04%	33.07%	-0.75%
Generator Revenue ($M)	66,390	59,628	52,242	59,283	91,473	62,829
Change from Base	0	-6,762	-14,148	-7,107	25,083	-3,561
Relative Change	0.00%	-11.34%	-27.08%	-11.99%	27.42%	-5.67%
Costs to Load ($M)	66,625	60,026	54,054	61,618	97,718	64,026
Change from Base	0	-6,599	-12,571	-5,007	31,093	-2,598
Relative Change	0.00%	-10.99%	-23.26%	-8.13%	31.82%	-4.06%
Load Wtd LMP ($/MWh)	71.8	69.1	62.2	66.4	105.3	69.0
Change from Base	0.0	-2.7	-9.6	-5.4	33.5	-2.8
Relative Change	0.00%	-3.91%	-15.39%	-8.12%	31.82%	-4.05%

Table 13: Sensitivity Analysis Results for 20% LOBO Scenario

PJM Sensitivities	20% LOBO	20% LOBO (LL)	20% LOBO (LL, LG)	20% LOBO (LG)	20% LOBO (LG, C)	20% LOBO (PF)
Production Costs ($M)	30,610	26,947	25,454	28,879	44,919	30,537
Change from Base	0	-3,663	-5,156	-1,731	14,309	-73
Relative Change	0.00%	-13.59%	-20.26%	-5.99%	31.86%	-0.24%
Generator Revenue ($M)	59,178	52,141	45,549	51,916	82,857	58,725
Change from Base	0	-7,037	-13,629	-7,262	23,679	-453
Relative Change	0.00%	-13.50%	-29.92%	-13.99%	28.58%	-0.77%
Costs to Load ($M)	61,341	52,551	47,541	54,528	90,294	59,197
Change from Base	0	-8,790	-13,800	-6,814	28,952	-2,144
Relative Change	0.00%	-16.73%	-29.03%	-12.50%	32.06%	-3.62%
Load Wtd LMP ($/MWh)	66.1	60.5	54.7	58.8	97.3	63.8
Change from Base	0.00	-5.62	-11.39	-7.35	31.21	-2.31
Relative Change	0.00%	-9.29%	-20.81%	-12.50%	32.06%	-3.63%

Table 14: Sensitivity Analysis Results for 30% LOBO Scenario

PJM Sensitivities	30% LOBO	30% LOBO (LL)	30% LOBO (LL, LG)	30% LOBO (LG)	30% LOBO (LG, C)	30% LOBO (PF)
Production Costs ($M)	25,708	22,255	20,778	24,092	36,517	25,506
Change from Base	0	-3,452	-4,930	-1,615	10,809	-201
Relative Change	0.00%	-15.51%	-23.72%	-6.71%	29.60%	-0.79%
Generator Revenue ($M)	56,860	49,648	43,001	48,969	79,940	55,769
Change from Base	0	-7,212	-13,859	-7,891	23,079	-1,091
Relative Change	0.00%	-14.53%	-32.23%	-16.11%	28.87%	-1.96%
Costs to Load ($M)	61,635	54,289	48,345	55,156	89,008	59,735
Change from Base	0	-7,346	-13,291	-6,479	27,372	-1,900
Relative Change	0.00%	-13.53%	-27.49%	-11.75%	30.75%	-3.18%
Load Wtd LMP ($/MWh)	63.2	59.3	52.8	56.6	91.3	61.3
Change from Base	0.00	-3.94	-10.43	-6.65	28.07	-1.95
Relative Change	0.00%	-6.65%	-19.76%	-11.75%	30.75%	-3.19%

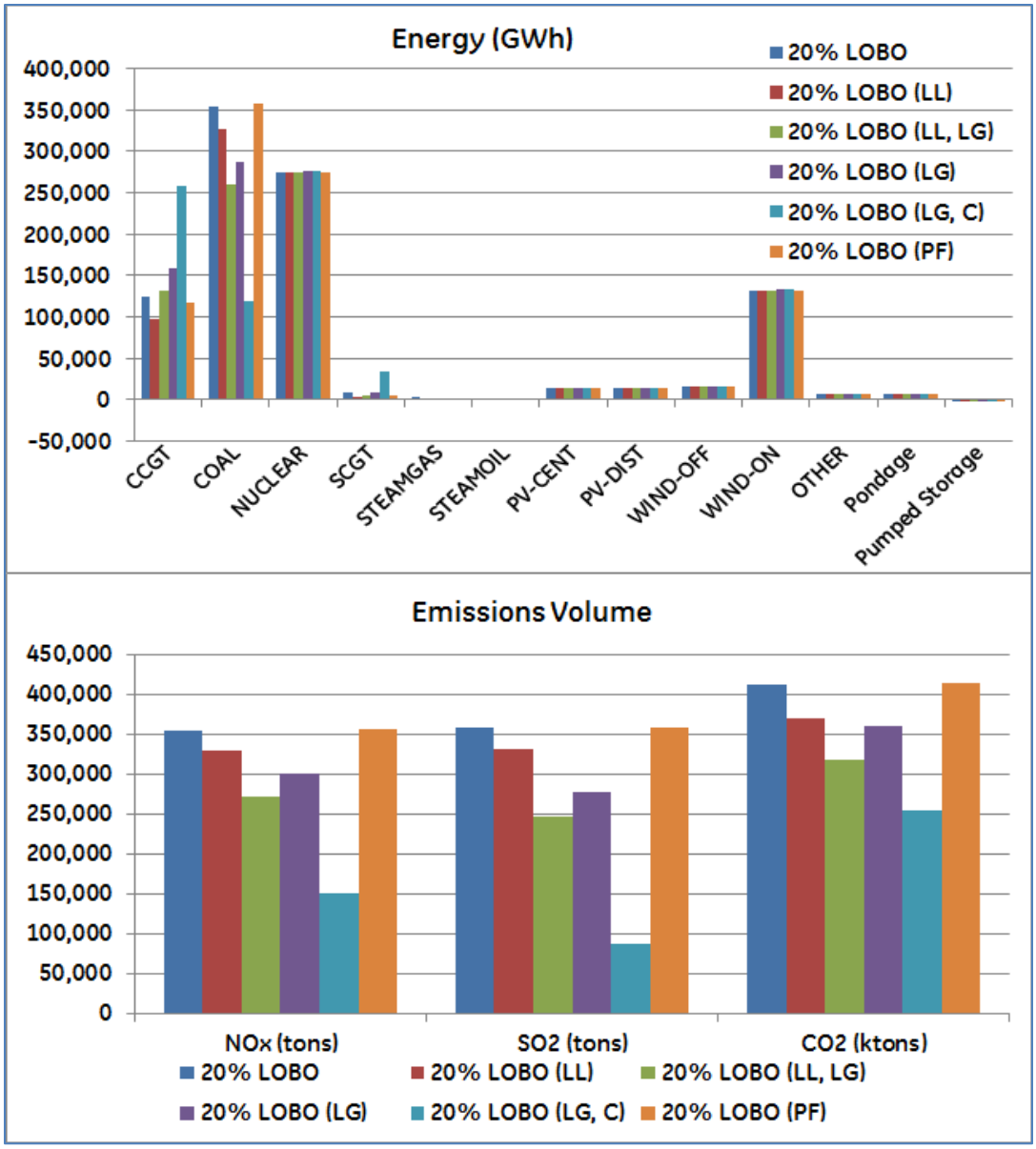

Figure 20: Sensitivity Analysis Results for 20% LOBO Scenario; Total Emissions and Energy by Unit Type

The sensitivity analysis revealed the following trends:

- Lower load growth caused a reduction of both coal and gas generation, resulting in lower production costs and average LMPs.
- Lower natural gas price caused an increase in gas-fired generation and a decrease in coal generation, also resulting in lower production costs and average LMPs.
- Lower natural gas price with increased carbon cost caused a dramatic decrease in coal generation and a significant increase in CCGT and SCGT operation. With the

carbon price included in the variable operating costs, total production costs and LMPs and load costs all increased by about 30% relative to the baseline assumptions.

- Lower load growth with lower natural gas price resulted in a reduction in coal generation, with minimal impact on the energy production of other generation resources.
- Perfect renewable forecast appeared to result in relatively small decrease in economic variables compared to the other sensitivities.
- Production cost savings from renewable energy can vary significantly depending on assumptions about fuel prices, load growth, and emission costs. For example, as shown in Table 15, compared to the base scenario, production cost savings in the 14% RPS scenario were 12.8% lower for the Low Load / Low Gas sensitivity and 39% higher for the Low Gas / High Carbon sensitivity.

Table 15: Impact of Sensitivities on Production Costs

	Base	(LL)	(LL, LG)	(LG)	(LG, C)	(PF)
Production Costs($M)						
2% BAU	40,470	36,099	34,370	38,341	59,763	40,462
14% RPS	33,719	29,791	28,482	32,102	50,380	33,470
20% LOBO	30,610	26,947	25,454	28,879	44,919	30,537
30% LOBO	25,708	22,255	20,778	24,092	36,517	25,506
Delta Relative to 2% BAU						
2% BAU	0	0	0	0	0	0
14% RPS	-6,751	-6,307	-5,888	-6,239	-9,383	-6,993
20% LOBO	-9,860	-9,151	-8,916	-9,462	-14,844	-9,925
30% LOBO	-14,763	-13,843	-13,592	-14,249	-23,246	-14,956
Compared to the Base Case						
2% BAU	-	-	-	-	-	-
14% RPS	-	-6.6%	-12.8%	-7.6%	39.0%	3.6%
20% LOBO	-	-7.2%	-9.6%	-4.0%	50.5%	0.7%
30% LOBO	-	-6.2%	-7.9%	-3.5%	57.5%	1.3%

14 Review of Industry Practices and Experience on Renewables Integration

This task investigated the current state of the art with variable generation integration, mostly focused on the United States but providing a few international examples where particularly relevant. The results are documented in a free-standing task report[10]. Key findings with particular relevance to PJM include:

Energy Market Scheduling

- Sub-hourly scheduling and dispatch, for both internal (within-RTO and within-utility) and for scheduling on external interconnections with other balancing authorities, improves performance relative to sub-hourly variability.

Visibility of Solar Distributed Generation

- Install telecommunications and remote control capability to clusters of solar DG in PJM's service area. Alternatively, have distribution utilities install such capability and communicate data and generation to PJM.
- Include distributed solar in variable generation forecasting.
- Account for the impacts of non-metered solar DG in load forecasting.
- Follow and/or participate in industry efforts to reconcile provisions in IEEE-1547 and Low-Voltage Ride-Through Requirements.

Reserves

- Consider separating regulation requirements into regulation up and regulation down if there is a shortage of regulation for certain hours, if there is a disproportionate need for a certain type of regulation (up or down), or if there is a desire to more finely tune regulation requirements.
- Have operating reserve requirements set by season or by level of expected variable generation, instead of a static requirement that changes infrequently.
- Use demand response to provide some reserves.
- Consider using contingency reserves for very large but infrequent wind and solar ramps.
- Require wind and solar generators to be capable of providing AGC.

[10] 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.

Wind and Solar Forecasting

- Implement a centralized forecasting system for wind and utility-scale solar that offers day-ahead, very short-term (0-6 hours), short-term (6-72 hours), and long-term forecasts (3-10 days).
- Ensure that short-term wind and solar forecasting systems can capture the probability of ramps, or implement a separate ramping forecast.
- Institute a severe weather warning system that can provide information to grid operators during weather events.
- Monitor the use of confidence intervals on forecast data and consider adjusting them periodically based on actual performance.
- Integrate the wind and solar forecasts with load forecasts to provide a "net load" forecast.
- Institute requirements for data collection from wind and solar generators that can be used to track forecast performance.

Intra-Day Unit Commitment: Consider establishing intra-day unit commitment, if one is not already in place, and incorporate short-term wind and solar forecasts.

Look-Ahead Dispatch: Consider Establishing a Look-Ahead Dispatch for very-short time frames.

Capacity Value of Wind and Solar: Conduct an ELCC study of wind and solar capacity value at regular intervals, and use them to calibrate or modify other approximate methods for calculating capacity values of wind and solar plants.

Wind Ramps: Require wind generators to be equipped with control functions that can limit ramp rates.

Frequency Response: Do not impose frequency response requirements on wind or central solar plants unless it is absolutely necessary.

15 Methods to Improve PJM System Performance

Several methods of mitigating operational issues or improving overall system performance were explored. The findings are summarized below.

Dynamic Procurement of Regulation Reserves

Study results show that the short-term variability in PJM load net renewables during a given hour is highly dependent upon the amount of wind and solar generation output during that hour. If the wind and solar generation is at a low level, then their contribution to variability is

small and the need for regulation is dominated by load variability. However, if wind and solar generation is high, then wind and solar variability dominate and more regulation is required. In an effort to minimize system operating costs, it would be prudent to only procure enough regulation to cover actual system needs each hour, as a function of wind and solar output each hour.

During this study period, PJM's practice was to set regulation requirements day-ahead as a percentage of forecast peak and valley load levels, and then to procure regulation during the operating day. When wind and solar penetration increases, PJM should consider a process to:

- Procure a portion of the necessary regulation in the day-ahead market, based on hourly forecast profiles of wind and solar generation.
- Dynamically adjust regulation procurement in the real-time market, based on short-term (1-2 hour ahead) wind and solar forecasts.

Figure 21 illustrates the process.

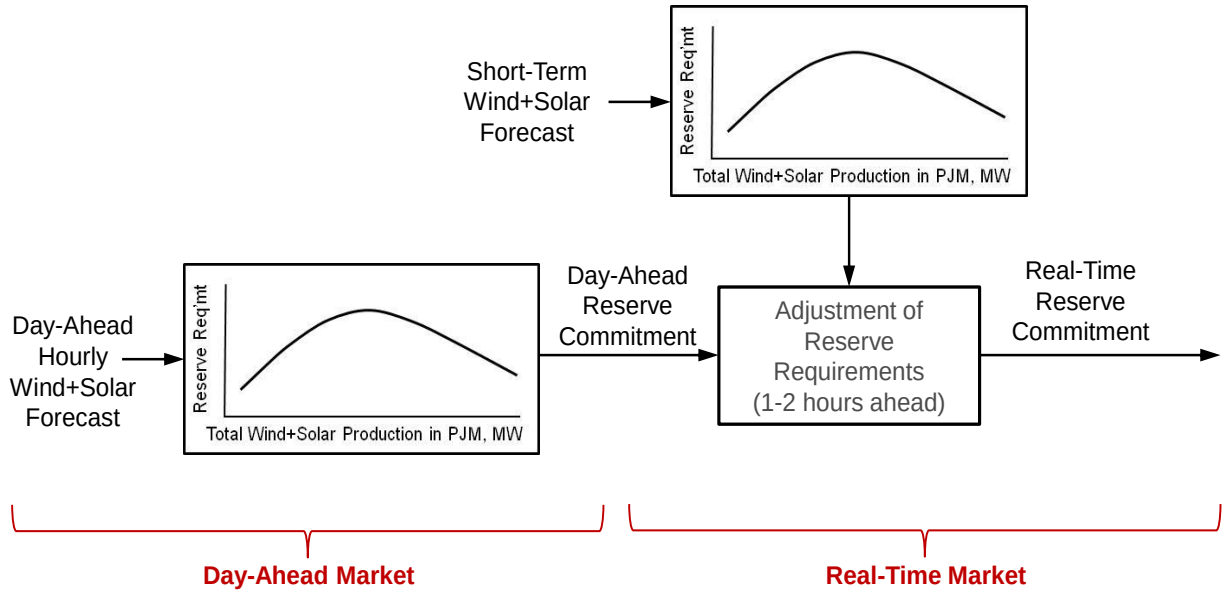

Figure 21: Process for Calculating Real-Time Regulation Requirements

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 in 2026, 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

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.

Figure 22 shows PJM production costs for the 14% RPS scenario. 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 23, which shows the change in CT dispatch for one day of operation in the 14% RPS scenario.

As a point of comparison, the bar on the right in Figure 22 shows that production costs would be reduced by $250M if perfect wind and solar forecasts were possible.

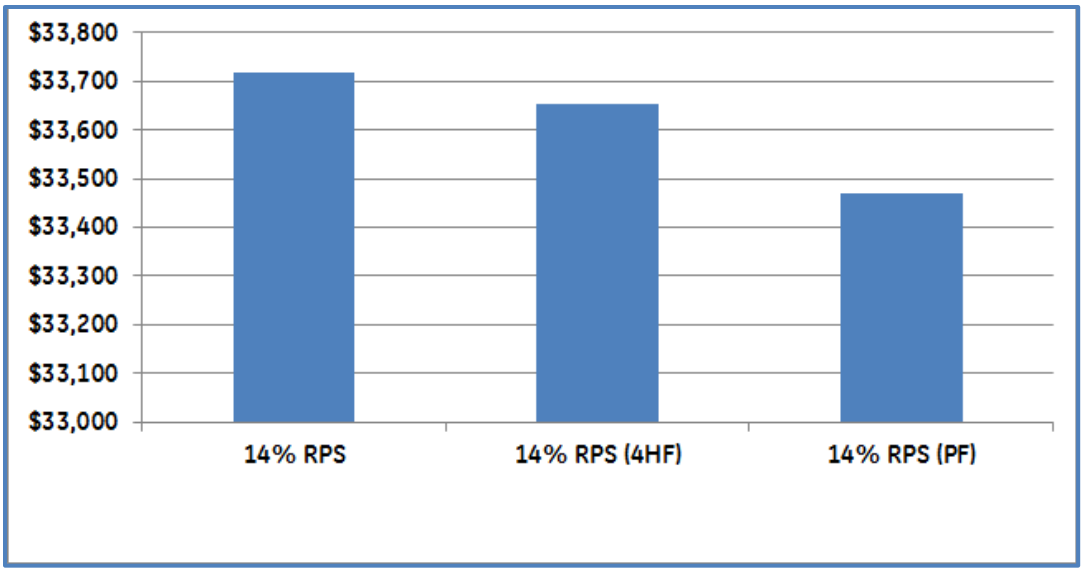

Figure 22: Production Cost Reduction with 4-Hour-Ahead Recommitment, 14% RPS Scenario

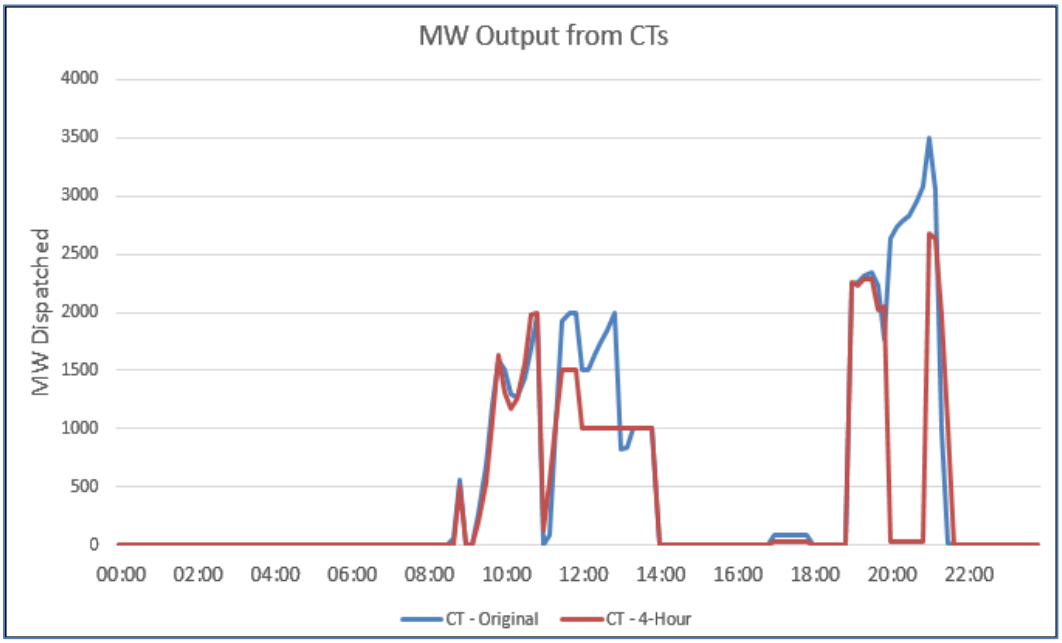

Figure 23: CT Dispatch for Existing Day-Ahead Unit Commitment Practice and 4-Hour-Ahead Recommitment (14% RPS Scenario, May 26)

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.

Storage or Demand Response Resources for Spinning Reserve

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 1000 MW of storage or demand response resources were used in place of generator resources for spinning reserves in the 30% LOBO scenario. Total system production costs were reduced by $17.41M/year, which corresponds to $1.99/MWh or $17.41/kW-year.

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). In fact, some storage resources are already participating in PJM's regulation market. However, 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 as renewable penetration increases. The market price of regulation and the capital costs of energy storage devices will ultimately dictate viability.

Ramp-Rate Capabilities of Existing Power Plants

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.

Figure 24 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-rate 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.

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-rate 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.

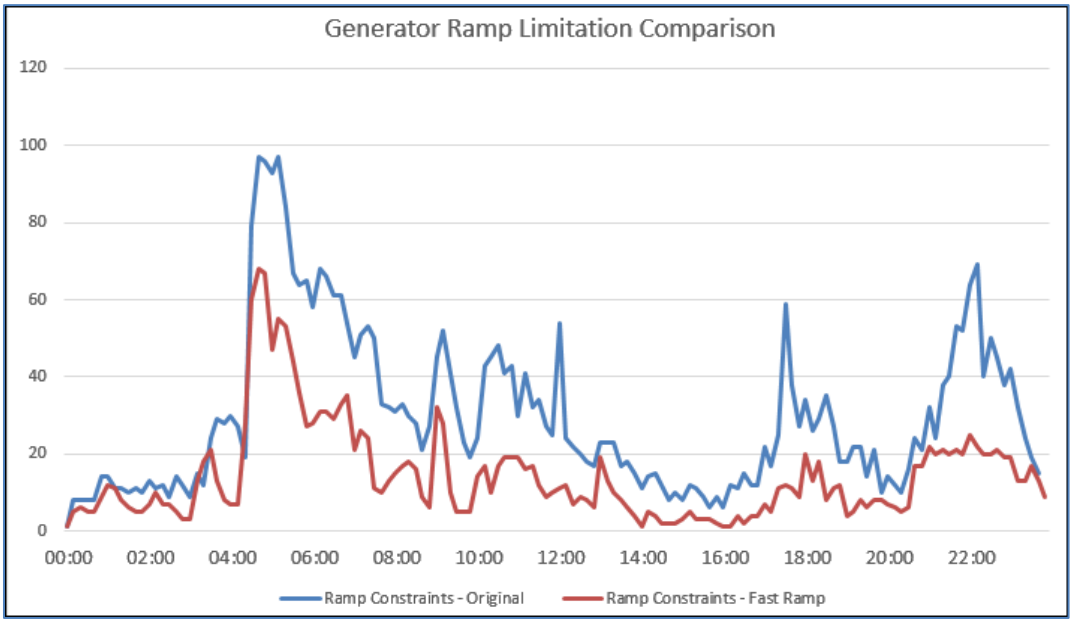

Figure 24: Number of Ramp Constrained Units with Existing Ramp Limits and 2%/min Ramp Limits

16 Topics for Further Study

Impacts of Reduced Energy Revenues for Conventional Power Plants

The study results show that as renewable penetration increases, wind and solar resources will displace energy production from conventional coal and gas generating plants. Energy revenues for conventional generation resources will decline significantly. To remain economically viable, these plants would either need to receive a larger share of their revenues from a capacity market or perhaps increase energy prices to help cover fixed costs. Alternatively, some conventional plants may not be viable and would be retired. It is suggested that PJM investigate the potential consequences of reduced capacity factors and energy revenues on its conventional generation fleet.

Flexibility Improvement for Conventional Power Plants

There is an emerging body of industry knowledge on methods for increasing the flexibility of power plants that have traditionally been operated as baseload units. A recent NREL study[11] summarizes recent progress. It is suggested that PJM investigate possible methods that could be applied to existing units with limited ramping or cycling capabilities.

Expanding System Flexibility through Active Power Controls on Wind and Solar Plants

Another potential source of system flexibility is from wind and solar plants. In the past decade, manufacturers have made significant advancements in control methods that can make plant power output responsive to grid-level controls, including frequency response and down-regulation. A recent NREL report summarizes several possible concepts related to frequency control[12]. Given the growing industry concern over declining frequency response performance of the Eastern Interconnection, it would be prudent for PJM to investigate how wind and solar plants could contribute to frequency response, and work towards interconnection requirements that ensure PJM will continue to meet its grid-level performance targets.

17 PJM PRIS Report Sections

PJM PRIS Report sections include the following:

- PJM PRIS Executive Summary Rev05
- PJM PRIS Meeting 2014-03-03 Rev09
- Final_Report_AWST_Final_23Sep2011
- Task1 Load Profile data
- Task2 Scenario Selection__012612
- best practices report final to GE Nov 2012

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[11] "Flexible Coal: Evolution from Baseload to Peaking Plant", National Renewable Energy Laboratory (NREL), December 2013, http://www.nrel.gov/docs/fy14osti/60575.pdf

[12] "Active Power Controls from Wind Power: Bridging the Gaps", National Renewable Energy Laboratory (NREL), January 2014, http://www.nrel.gov/docs/fy14osti/60574.pdf

- PJM PRIS - Task 3A Part A – Modeling and Scenarios
- PJM PRIS - Task 3A Part B – Statistical Analysis and Reserves
- PJM PRIS - Task 3A Part C – Transmission Analysis
- PJM PRIS - Task 3A Part D – Production Cost Analysis
- PJM PRIS - Task 3A Part E – Sub-Hourly Analysis
- PJM PRIS - Task 3A Part F – Capacity Valuation
- PJM PRIS - Task 3A Part G – Plant Cycling and Emissions
- PJM PRIS - Tasks 3B & 4 - Market Analysis and Mitigation

imagination at work