Energy Transition in PJM:
Emerging Characteristics of a Decarbonizing Grid

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Contents

Executive Summary **1**

Findings *2*

Analysis Framework **7**

Scenario Development *7*

Resource Adequacy Assessment **10**

Effective Load Carrying Capability Analysis *10*

Impact of Renewable Penetration on Net Demand *12*

The Capacity Value of Renewables – ELCC Results *13*

Electrification – Impact on Resource Adequacy *14*

Resource Adequacy Implications *16*

Energy & Ancillary Service Market Simulations **17**

Locational Marginal Prices *17*

Generation Dispatch *18*

Operating Reserve Demand Curve (ORDC) *18*

Energy Storage *20*

Interchange, Congestion, Renewable Generation Curtailments and Electrification *20*

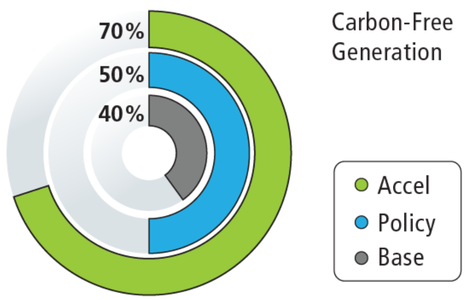
Ramping *21*

Moving Forward **24**

Executive Summary

Driven by PJM's strategic pillars – facilitating decarbonization reliably and cost-effectively, planning/operating the grid of the future, and fostering innovation – PJM has embarked on a multiphase, multiyear effort to study the potential impacts associated with the evolving resource mix. The second phase of this "living study" is built upon the foundations laid down in the paper "Energy Transition in PJM: Frameworks for Analysis."

The diverse set of PJM state policies were synthesized into three scenarios in which an increasing amount of the annual energy is served by carbon-free generation (40%, 50% and 70%). The assumptions embedded in the three scenarios – Base, Policy and Accelerated – were refined and extended in order to analyze the impact of four major sensitivities: electrification (electric vehicles and heating), energy storage, interregional interchange and the inclusion of a downward-sloping Operating Reserve Demand Curve (ORDC) into the Energy and ancillary services markets. An entire year of the Energy Market was simulated with an hourly resolution, and the capacity contributions of renewable resources were evaluated using the Effective Load Carrying Capability (ELCC) methodology.



State policies were synthesized into three renewable scenarios.

- The **Base** is a counterfactual scenario with 40% of the annual energy in PJM footprint coming from carbon-free generation.
- In the **Policy** and **Accelerated** scenarios, carbon-free generation represents 50% and 70% of the annual energy, respectively.

Refined Study Assumptions				
Storage **6 GW =** Stand-Alone **31 GW =** Solar Hybrid 	**Solar** **21 GW =** Stand-Alone **65 GW =** Solar Hybrid 	**Electrification** **~19 GW =** 17M EVs **14 GW =** Heating 	**Interchange** **Historical Levels of Interchange** 	**Reserves** **Downward-Sloping ORDC** 

Findings

The results of the second phase of this "living study" suggest five key focus areas for the PJM stakeholder community and delineate the subsequent phases of the study:

1 | Electrification shifts the seasonal resource adequacy risk to winter.

2 | Retail rate design and energy storage become increasingly important with electrification.

3 | Market reforms are needed to incentivize flexibility and mitigate uncertainty.

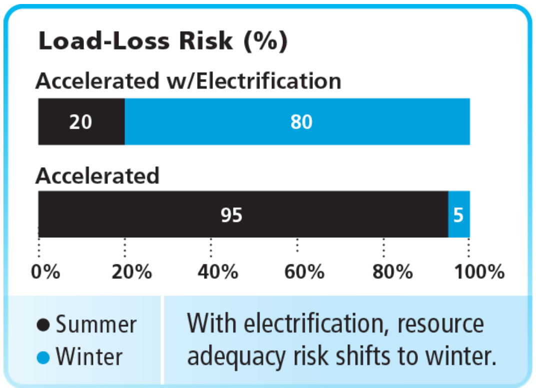
4 | The integration of renewable resources increases the need for balancing resources to meet forecasted ramping requirements.

5 | Energy storage (four hours) enhances operational flexibility, but seasonal capacity and energy constraints require transmission expansion, long-term storage and other emerging technology.

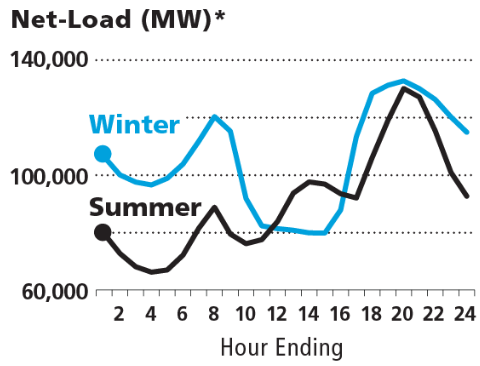
1. Electrification Shifts Resource Adequacy Risk to Winter

Electrification reinforces the need for an adequate supply of thermal resources to meet the winter demand until a different technology can provide a capacity substitute at scale. Given the shift in resource adequacy risk to winter, it will be critical to explore the impact of common modes of failure that lead to correlated outages. PJM and stakeholders should explore the implications of a seasonal market product differentiation.

Traditionally, resource adequacy risk in PJM has been concentrated in the summer season. In the **Accelerated** scenario, 95% of the load-loss risk is experienced in the summer and the remaining 5% in winter. However, electrification – in particular heating – has an asymmetrical impact, with the demand growth in winter more than doubling that in summer (summer load growth is 7%; winter 15%). Consequently, there is a pronounced shift in both the seasonal and hourly risk profiles, forcing a new seasonal split of load-loss risk of 20% summer and 80% winter.



With electrification, the winter net-load hourly profile has a slightly higher, but substantially wider, peak demand than that of summer. Approximately 60% of the load-loss risk in winter is concentrated during the last four hours of the day. The net-load hourly profile is also considerably flatter in winter, spreading the remaining 40% risk across multiple hours of the day.



Net-load profile in winter is flatter, with a slightly higher, but considerably wider, peak demand.

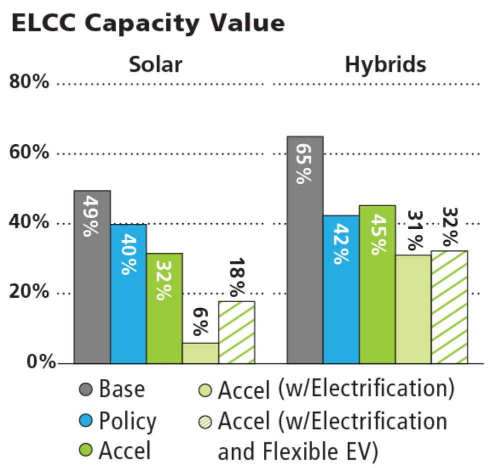
*Accelerated with electrification

2. Electrification Increases Role of Retail Rate Design and Storage

The complementary relationship of the generation portfolio and load shape has a profound impact on the ELCC capacity accreditation. Retail rate design reduces the amount of capacity procured and triples the capacity contribution of solar in the electrification scenario. Solar-hybrid resources have a higher capacity value under all scenarios. It will be critical for PJM and stakeholders to continuously improve and incorporate sophisticated methods to accurately account for the capacity value contribution of all generation resources.

In general, as the penetration of a particular renewable resource increases, its capacity value contribution tends to decrease. However, this somewhat gradual trend can be deceiving. At a fundamental level, the ELCC methodology exhibits a nonlinear behavior that is a strong function of the complementarity between the generation portfolio and load shape.

Electrification reshapes the load hourly profile, shifting the resource adequacy risk to winter. Assuming an inelastic demand behavior (i.e., electricity demand is insensitive to price), 60% of the load-loss risk is concentrated in the last four hours of the day, and, as a result, the capacity value of solar abruptly drops from 32% to 6%. The opposite trend is observed for wind resources, with a threefold increase in capacity value (onshore wind, 6% to 22%; offshore wind, 15% to 45%).



With electrification, the capacity value of solar drops to 6%. Demand elasticity and energy storage increase the capacity value of solar.

Retail rate design can harmonize the load-loss risk profile with renewable resources. Assuming that customers have access to real-time prices, Internet of Things (IoT) technology, and customer-facing programs that incentivize electric vehicle (EV) charging in off-peak hours, the capacity value of solar climbs back to 18%. The net effect of retail rate design is an overall reduction of the amount of capacity procured to meet the North American Electric Reliability Corporation's 1-in-10 Loss of Load Expectation (LOLE) reliability standard.

Similarly, energy storage increases the capacity value of solar under all studied scenarios. Energy storage and retail rate design do not have a simple additive effect. In general, energy storage thrives on arbitrage opportunities, while retail design tends to shave high load-loss risk hours, flattening the load curve.

3. Market Reforms Needed to Incentivize Flexibility

The operational flexibility needs of the system increase with the integration of renewable resources, requiring on average up to 7.5 GW of synchronous reserves to maintain reliability. Under high renewable penetration, energy storage resources supplied more than 80% of the reserve requirements. There is an opportunity for PJM and stakeholders to explore the participation of renewable resources in the reserves market.

The market must accurately reflect and properly incentivize the flexibility needs of the system. The current Reserve Market construct utilizes a two-step ORDC, and while it accurately reflects the risk posed by a single contingency, it fails to capture the rise in uncertainty driven by the penetration of renewable resources. The simulation results underscored the deficiencies in the current construct, indicating that the two-step ORDC procures less than a third of the reserves needed by the system and, with an average clearing price of $0.02/MWh, it also fails to send long-term market signals to incentivize flexibility.

The study evaluated the effects of incorporating a downward-sloping ORDC. By design, reserve products constructed using a downward-sloping ORDC procure a variable amount of reserves based on the prevailing uncertainty in the operating system conditions. Simulation results indicate that a noteworthy average of up to 7.5 GW of synchronized reserves were procured in order to maintain system reliability. The modeled Reserve Market reforms also improved price formation, sending a strong signal for flexible resources with an average price of $4/MWh. Despite the fact that FERC has recently remanded PJM's proposal to incorporate a downward-sloping ORDC, the results of the study suggest that certain market reforms will be needed to address the rise in variability and uncertainty under high renewable penetration. PJM does not intend to rehash the ORDC proposal.

Interestingly, as the penetration of renewable resources increases, so does the provision of reserves coming from energy storage resources. In the Accelerated scenario, more than 80% of the reserve requirements were supplied by storage.

4. Balancing Resources Needed for Ramping

The study shows an increasing need for balancing resources to meet ramping requirements, with frequent slopes in excess of 10 GW/hour and extremes in excess of 20 GW/hour. The geographical diversity of the PJM footprint smooths out the net variability of renewable resources. Net-load ramping requirements are more severe in winter due to the adverse alignment between the native-load ramping and the variability of renewable resources. Thermal resources supplied 50% of the ramping needs; the remaining 50% was delivered by a combination of hydro, storage and regional interchange.

The variability of renewable resources drives the need for increased operational flexibility. In the Accelerated scenario, the driving mechanism for the ramping requirements is evenly split: 50% coming from native-load ramping and 50% from the variability of renewable resources. The simulation results show a drastic increase in the net-load ramping requirement, with a 90th percentile slope of 10 GW/hour and a maximum slope exceeding 20 GW/hour. It is also important to emphasize that in certain extreme days, the total climb from the beginning to the end of the ramping period was over 70 GW – that's more than peak summer loads in New York and New England *combined*.

The study also shows that the penetration of renewable resources has an asymmetrical seasonal impact on the ramping needs, increasing the net-load ramping slope by 80% in winter but only by 40% in summer. Interestingly, such asymmetry is not driven by a difference in renewable variability across seasons but by the adverse alignment with the winter load shape. The geographical diversity of the PJM footprint smooths out the net variability of renewable resources (onshore wind + offshore wind + solar), making it fairly uniform across seasons and symmetric with respect to the direction (i.e., both positive and negative ramps have similar magnitudes).

Under high renewable penetration, thermal resources performed a critical role maintaining reliability, typically supplying 50% of the ramping needs (42% gas, 8% coal). Hydro resources (including pumped-hydro storage) delivered up to 15% of the ramping needs. The contribution from hybrid resources, energy storage and regional interchange varied across the ramping period. Due to the assumed limited duration of energy storage (four hours), the contribution of stand-alone batteries and solar-hybrid resources ranged from single-digit percentage to 40%. Regional interchange was inversely correlated to hybrid resources, acting as a buffer when storage was depleted and supplying 10% to 25% of the ramping needs.

5. Transmission, Storage and Other Emerging Technology Solutions Required

Energy storage (four-hour) is decidedly complementary to renewable resources and enhances operational flexibility. However, seasonal capacity and energy constraints will drive the need for a broader spectrum of solutions, including regional transmission expansion, long-term/seasonal storage and other emerging technology. There is also an opportunity for PJM and stakeholders to explore the potential complementary interaction of renewable generation in PJM and the Eastern Interconnection.

The renewable integration scenarios included up to 6 GW of stand-alone storage (four-hour duration) and 30 GW of storage coupled to 35 GW of solar hybrid resources. The simulation results indicate that storage had a profound impact in the ancillary services market, providing up to 80% of synchronous reserves in a cost-effective manner. Furthermore, from a resource-adequacy perspective, energy storage was complementary to all generation portfolios with varying amounts of renewable resources and electrification.

Despite the enhanced operational flexibility that four-hour energy storage provides to the system, the study highlighted seasonal capacity and energy constraints that would necessitate a broader spectrum of solutions, including regional transmission expansion, long-term/seasonal storage and other emerging technologies.

Transmission congestion patterns changed drastically, and overall congestion increased by 60%. The simulated scenarios also included a sensitivity in which the interregional available transfer capability was artificially limited to historical levels (less than 15 GW). This sensitivity provides a proxy for a situation in which PJM cannot fully leverage the available transfer capability in the system, either because the rest of the interconnection also has an excess of renewable generation or due to transmission constraints.

Under such a scenario, and despite the substantial penetration of energy storage (in excess of 40 GW including pump storage), renewable curtailments represented 16% of the total renewable generation production. As a point of comparison, in the counterfactual scenario – without energy storage but leveraging the entire existing interregional transfer capability and assuming the rest of the interconnection can import the power – the renewable curtailments were 10%.

Analysis Framework

Scenario Development

In the second phase of the study, the assumptions used to build the renewable integration scenarios were refined and extended in order to analyze the impact of four major sensitives: electrification (electric vehicles and heating), energy storage, interregional interchange and the inclusion of a downward-sloping Operating Reserve Demand Curve (ORDC) into the Energy and ancillary services markets. The overall energy served by carbon-free generation remained the same, with a target of 40% for the **Base** scenario, 50% for the **Policy** scenario and 70% for the **Accelerated** scenario. The development of the scenarios was informed by state policies that were in place as of April 2020, but this phase of the study incorporates sensitivities to reflect recent federal initiatives.

Figure 1 shows the renewable generation expansion in the **Base**, **Policy** and **Accelerated** scenarios. **Table 1** shows the main difference between the modeling assumptions in first and second phases of this study. Similar to the first phase, the gross load from the long-term load forecast for the year 2035 was used in all scenarios. The net load varied slightly in each scenario to account for the impact of behind-the-meter solar.[1] This second phase incorporated load growth sensitivities to assess the impacts of high electrification. Electrification sensitivities simulated the impact of a high penetration of electric vehicles[2] and electric heating. The hourly load profile reflects two different consumer behaviors:

- EV charging that mimics today's inelastic consumer behavior. Under this assumption, EV charging has a compounding effect on peak load.
- EV charging moves to off-peak hours, primarily toward the overnight hours. This behavior emulates a price-responsive elastic demand with access to real-time prices, Internet of Things (IoT) technology and customer-facing programs that incentivize EV charging in off-peak hours.

The overall nameplate capacity of renewable generation is identical to that in the first study phase, but the solar generation portfolio was altered to include hybrid resources. The portfolio includes up to 21 GW of stand-alone solar and 65 GW of solar/storage hybrids. This second study phase also incorporated 6 GW of stand-alone storage. All portfolios included formal deactivation notices as well as state or utility policies or agreements that include the shutdown of fossil generation beyond units that have formally submitted deactivation notices to PJM. Additional fossil generation retirements were included in the Policy and Accelerated cases in order to offset the additional capacity added by the renewable buildout. The study assumed that existing nuclear generation resources would remain operational through the Policy reference years.

[1] For the Base and Policy scenarios, the IHS Markit behind-the-meter (BTM) solar forecast was used to determine the renewable energy contribution from BTM solar resources. The Base scenario used the expected BTM solar penetration in 2023 from the IHS Markit solar forecast and scaled it up to 2035 load levels. The Policy scenario used the 2035 BTM solar forecast. In order to produce BTM solar values for the Accelerated scenario, guidance was taken from the Energy Information Administration on regional BTM solar growth between 2035 and 2050 to scale up the Policy scenario values.

[2] Tied to the White House target of 50% of light-duty vehicle sales being EVs by 2030; this results in much more EV stock than was assumed in the 2021 Load Forecast.

The generation profile for existing renewable generators was generated using unit-specific historical hourly profiles. A synthetic hourly profile was generated for all new renewable resources using data from the National Renewable Energy Laboratory (NREL). The synthetic profiles respect geographical weather patterns. Thermal resources were dispatched based on a Security Constrained Economic Dispatch. Monthly fuel price forecasts from the IHS Markit Fast Transition Case for 2035 were utilized in all scenarios. Mapping of units to fuel price points was derived from fuel cost policies.

Finally, all scenarios were based on a nodal transmission system from the most currently available RTEP case. The model monitors transmission constraints for 230 kV and above. Reliability upgrades identified in the Offshore Wind Transmission Study were included in the Policy and Accelerated scenarios.

Figure 1. Renewable Generation Expansion in Policy and Accelerated Scenarios

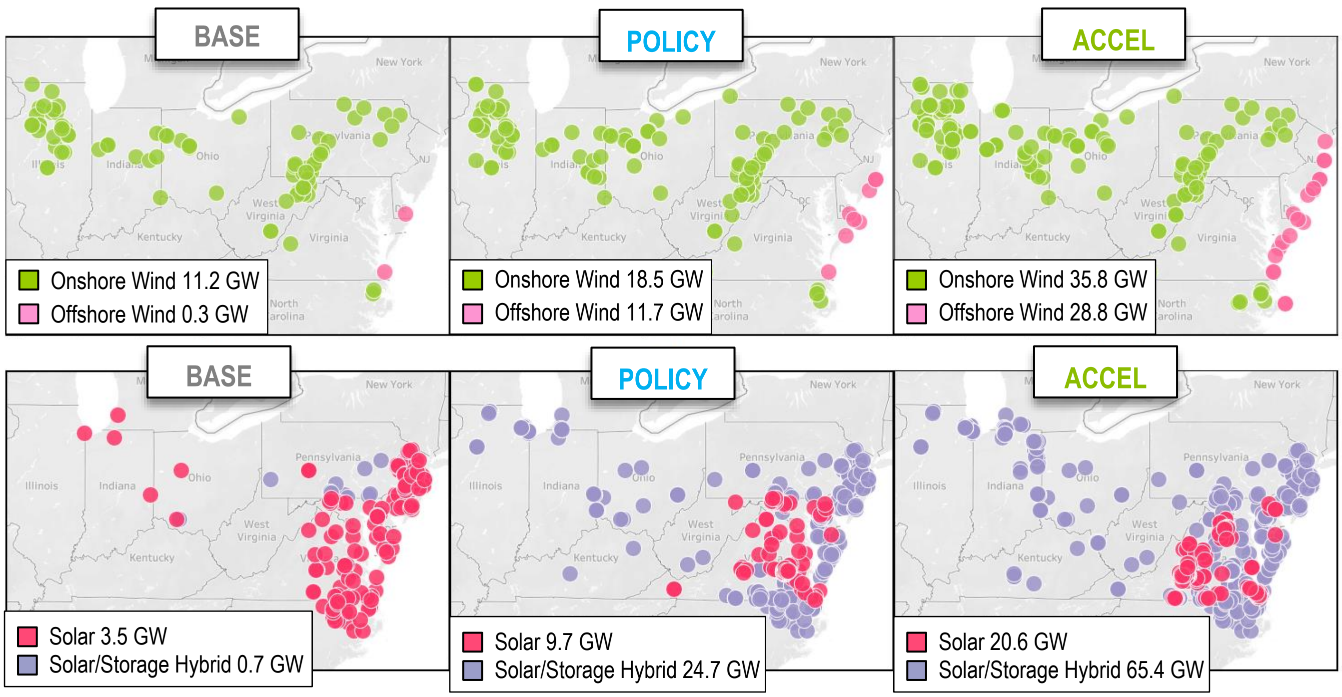


Table 1. Modeling Assumptions – First Study Phase vs. Second Study Phase

	Study Phase 1	Study Phase 2
Energy Storage	Only existing pump storage	• Existing pump storage • Up to 6 GW of stand-alone storage and 31 GW of storage coupled to solar
Interchange	Full available transfer capability (+20 GW with MISO)	Available transfer capability artificially limited to historical levels (less than 15 GW)
Renewable Resources	***Up to:*** • 29 GW offshore wind • 36 GW onshore wind • 55 GW solar	***Up to:*** • 29 GW offshore wind • 36 GW onshore wind • 21 GW solar • 65 GW solar/storage hybrid (34 GW of solar + 31 GW of storage)
Load	2020 long-term load forecast for the year 2035 (all scenarios) Peak Summer: 159,868 MW Peak Winter: 141,513 MW	2021 long-term load forecast for the year 2035 and electrification sensitivity (heating and electric vehicles with/without elastic consumer behavior) Peak Summer: 154,620 Peak Winter: 136,304
Synchronous Reserves	Two-step ORDC	Downward-sloping ORDC Renewable variability impacts the reserve requirement
Fuel Prices[3]	• Natural Gas: $4.86/MMBtu • Oil: $16.50/MMBtu • Coal: $2.16/MMBtu	• Natural Gas: $4.70/MMBtu • Oil: $15.20/MMBtu • Coal: $2.10/MMBtu
Emissions Allowance Prices	Carbon Dioxide (CO_2), Regional Greenhouse Gas Initiative (RGGI)[4]: $15.50/ton Nitrogen oxides (NO_x)[5]: $2.36/ton; $88.50/ton for ozone season Sulfur dioxide (SO_2)[4]: $2.36/ton	

[3] Fuel prices were updated utilizing long-term forecasts for the year 2035 from IHS Markit. Values in Table 1 are annual average input values for resources in PJM region.

[4] CO_2 costs applied to generators within the scope of the RGGI program: fossil-fuel-fired electric power generator with a capacity of 25 MW or greater in NJ, MD, DE, VA and PA. The RGGI program allowance price floor (Emissions Containment Reserve) trigger price for 2030, escalated to 2035, was used for the allowance price.

[5] NO_x and SO_2 were modeled on a unit basis using EPA emissions rate and allowance price data from 2018. SO_2 data was averaged for the year. NO_x data was averaged separately for the ozone season (May through September) and the remainder of the year.

Resource Adequacy Assessment

Resource or capacity adequacy of the PJM system is assessed using Loss of Load Expectation (LOLE). LOLE is a measure of how often, on average, the available capacity is expected to fall short of demand. LOLE is a statistical measure of the frequency of firm load loss and does not quantify the magnitude or duration of firm load loss. The use of LOLE to assess resource adequacy is an internationally accepted practice. PJM resource adequacy studies are computed using the LOLE criterion of one day in 10 years (translated as 0.1 days per year for annual analyses).

Effective Load-Carrying Capability (ELCC) is a means of assessing resource reliability value (also referred to as capacity value) tied to the concepts of resource adequacy and probabilistic evaluation. For traditional resources, such as a thermal generator, ELCC will approximately be equal to its Unforced Capacity (UCAP) value (where UCAP value is determined based on the resource's forced outage rate). For variable or energy-limited resources, such as wind, solar and energy storage, ELCC methodology can be applied to derive a UCAP-equivalent value. ELCC results are driven by those hours with high risk or high loss-of-load probability (i.e., hours experiencing shortage or near-shortage conditions). These risk hours may vary as penetration of the resource increases.

In the analysis, each portfolio under examination has the same gross load but varying amounts of solar (both behind the meter and in front of the meter), onshore wind, offshore wind and energy storage. These varying penetration levels have an impact on net demand – or the amount that needs to be met after taking into account contributions from renewables – and, ultimately, on the reliability value of the variable resources. In addition, electrification load sensitivities were also run that add additional electric vehicles[6] as well as additional electric heating;[7] this, too, can impact reliability value.

Effective Load Carrying Capability Analysis

Effective Load Carrying Capability analysis requires lining up expected renewable output profiles with demand to capture the relationship between variable resource performance and load. The analysis is performed at an hourly level due to data availability and software constraints. It is also important to look at a range of weather scenarios. Wind and solar resources have variable performance, and the coincidence of renewable performance with high-demand hours or high-risk hours determine the capability/reliability value awarded. This coincidence can be impacted by the scenarios studied. Thus, the more years examined, the greater the variance is understood and the greater the confidence in the results. For this particular analysis, scenarios were used from 2012 to 2019 based on load, solar and wind output profiles constructed from available data. Results are sensitive to the data, and different data (or years examined) may lead to different results.

[6] In the Base, Policy and Accelerated cases, electric vehicles are not separated from gross load and are modeled consistent with how they were modeled in the 2021 Load Forecast. The electrification sensitivity separates this load out and gives it a shape.

[7] In the Base, Policy and Accelerated cases, electric heating assumptions are consistent with the 2021 Load Forecast. The electrification sensitivity assumes some fuel switching from fossil-based heating to electric-based heating.

This analysis is done in two steps: first by evaluating the total amount of variable resources to determine the capacity value of the entire pool of variable and energy-limited resources, then by allocating the total pool to each resource type (solar, onshore wind, offshore wind and energy storage).[8] Evaluating the total capability is an important step as it allows the model to capture the potential complementary nature of the different resource types.

Figure 2. ELCC Portfolio Value for Variable Resources

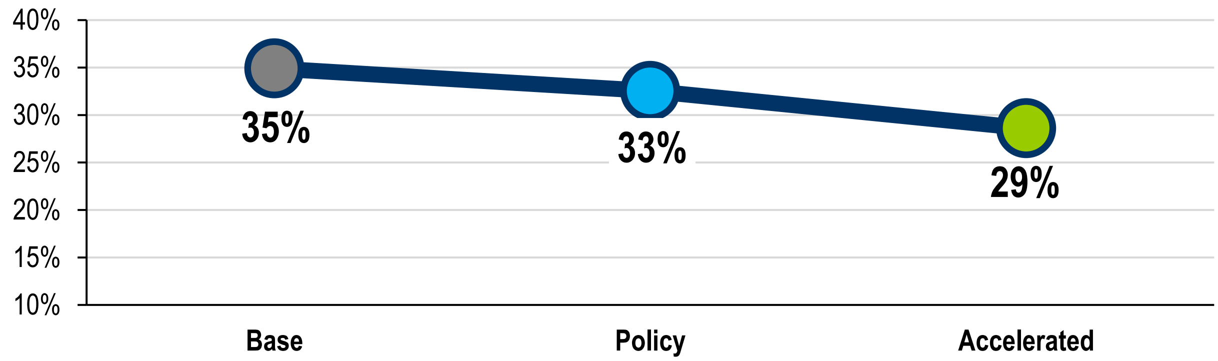
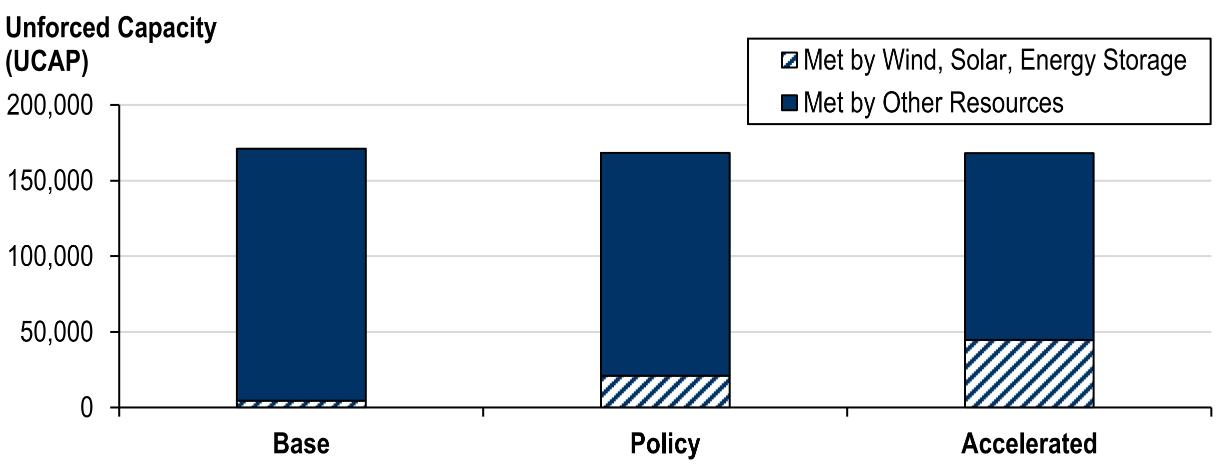


Figure 2 shows the results as variable resource penetration increases from the Base to Policy to Accelerated cases. The ELCC analysis shows that for ELCC resources, the capacity value of the portfolio (as a percentage of total nameplate capability) decreases as penetration increases.

PJM annually conducts the Reserve Requirement Study (R-Study), which is the source of two key figures: the Installed Reserve Margin (IRM) and the Forecast Pool Requirement (FPR). IRM is a percent value that dictates how much capacity on top of forecasted load needs to be procured in order to meet the LOLE criterion of 0.1 days per year. The FPR is a conversion of the IRM concept into UCAP terms, the unit of measure in the Reliability Pricing Model (RPM or capacity market). The **Figure 3** below shows the UCAP requirement to meet the LOLE criterion as well as how the transition to an ELCC-based concept for determining variable resources' UCAP value allows better alignment of capacity offers with reliability value.

Figure 3. UCAP Value of Resources in the Base, Policy and Accelerated Scenarios



[8] In practice, there would need to be an additional step to allocate to individual resources, though that additional step is outside the scope of this study.

Impact of Renewable Penetration on Net Demand

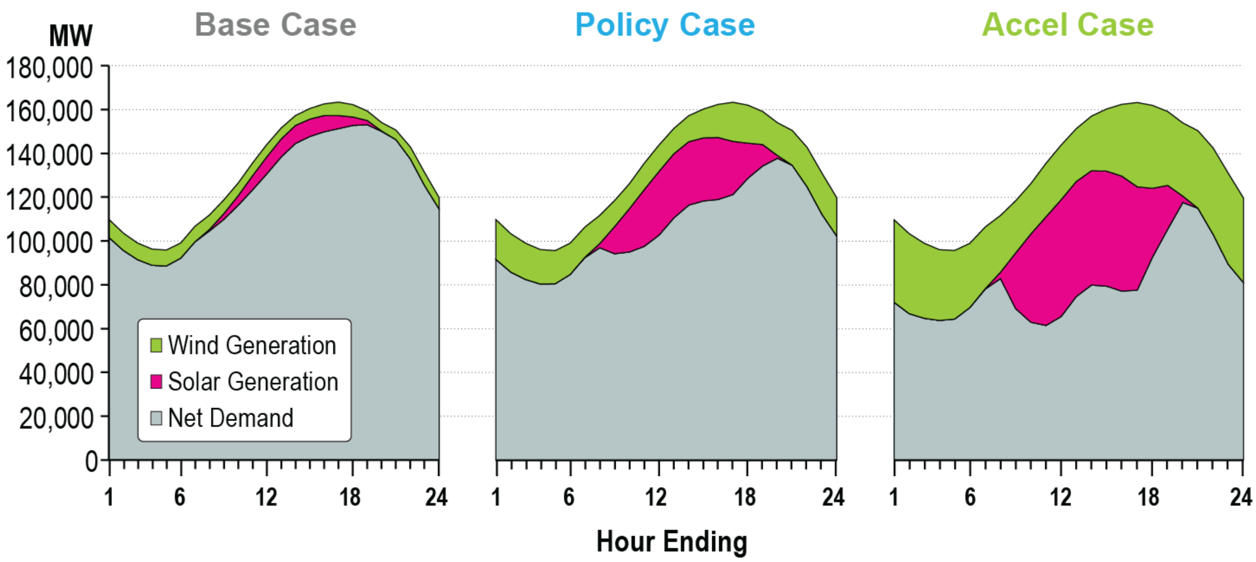
The impact of renewable penetration on net demand can be illustrated by looking at load corresponding to weather on Aug. 28, 2018, for each of the scenarios: Base, Policy and Accelerated. For the purposes of this exercise, we will define net demand as system load decremented by the amount of renewable generation.

In this example day (see **Figure 4**), for the Base case, the daily net demand peaks between 18:00 and 19:00 Eastern. However, net demand values for a seven-hour period (14:00–21:00 Eastern) are within 5% of the daily peak.

For the Policy case, the daily net demand peaks between 19:00 and 20:00 Eastern, and it also has a noticeably peaked shape relative to the Base case. Net demand values for only the three-hour period between 18:00 and 21:00 Eastern are within 5% of the daily peak.

For the Accelerated case, the daily net demand peaks between 19:00 and 20:00 Eastern and also is characterized by a peaked shape relative to the Base case. Net demand values for only the period between 19:00 and 21:00 Eastern are within 5% of the daily peak.

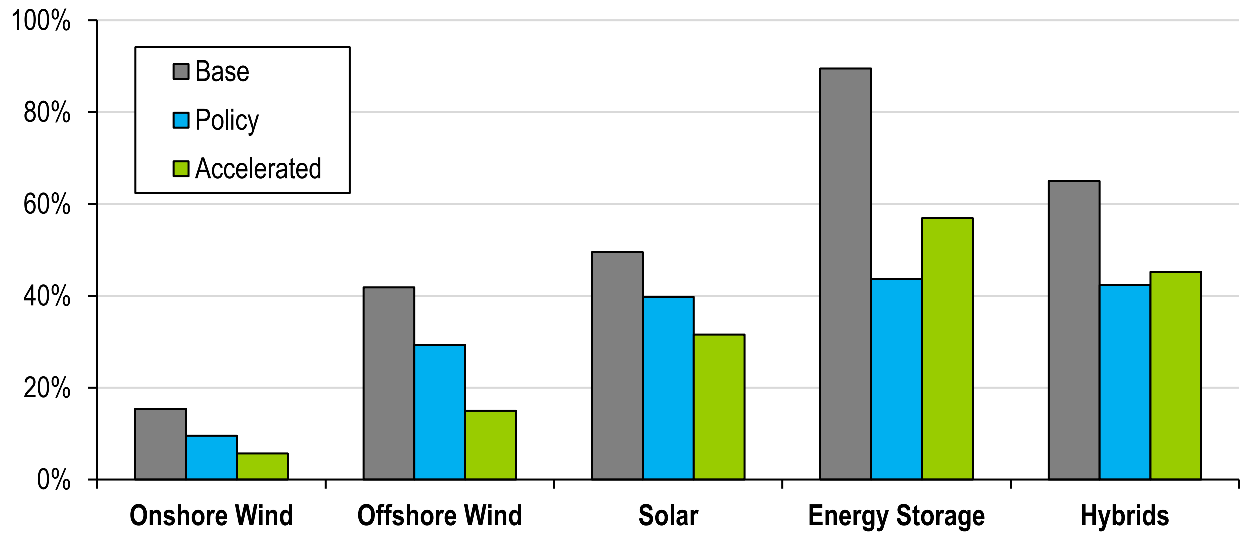
Figure 4. Aug. 28, 2018, Demand for Base, Policy and Accelerated Scenarios



The Capacity Value of Renewables – ELCC Results

Capacity value of a resource is influenced by a number of factors: load shape, resource profile shape, resource variance, amount of resources and complementarity with other resources. Generally speaking, each resource's value goes down with each successive portfolio as more of the respective resource is added (see **Figure 5**).

Figure 5. Effective Load Carrying Capability Results by Resource Type

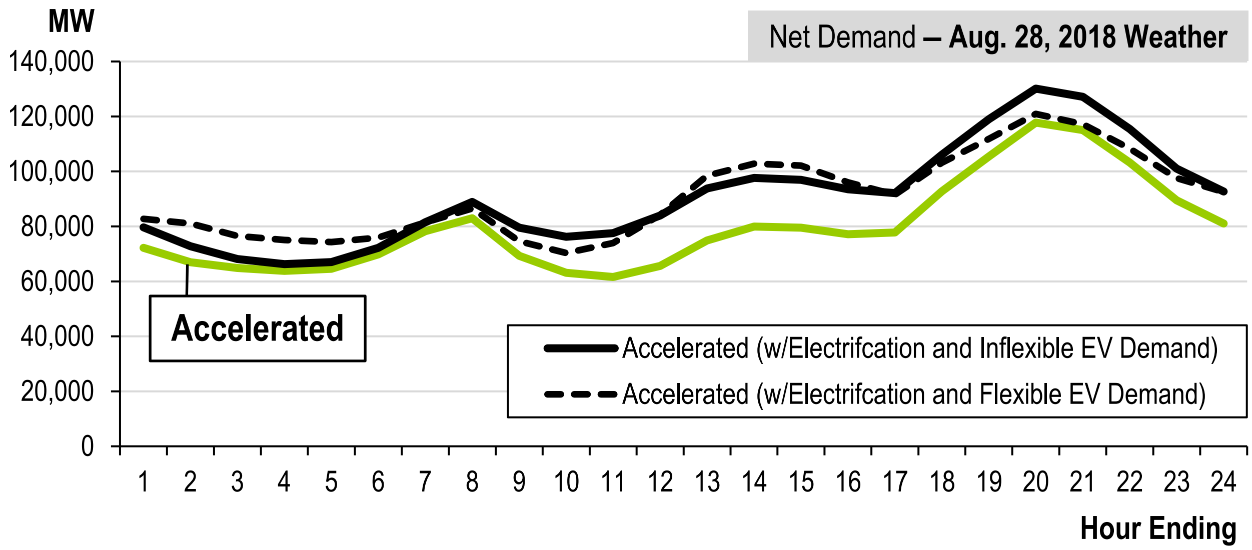


The exception to this trend is energy storage (and hybrids that are part solar, part energy storage), and the reason has to do with how the resources complement each other. The Accelerated scenario adds a significant amount of solar resources, which makes the peak demand net of intermittent resources noticeably higher and in turn more accommodating for energy storage. As mentioned in the previous section and seen in **Figure 6**, increasing solar penetration causes the number of high-load hours (within 5% of peak) to decline from seven hours in the Base scenario to just two hours in the Accelerated scenario. As a result, storage resources have a greater resource adequacy contribution in the Accelerated scenario because they can discharge stored energy over a shorter duration.

Electrification – Impact on Resource Adequacy

The electrification load sensitivity uses the same resource portfolios as used in the Base, Policy and Accelerated scenarios but differs in the gross demand assumptions. Specifically, the electrification sensitivity adds additional electric vehicles (EVs) as well as additional electric heating. For EVs, two shapes are considered: inflexible and flexible. Inflexible is meant to approximate the manner in which EVs are charged currently, which results in a larger increase in peak profile from the original load forecast. The flexible scenario assumes that some effort will be made to lessen EVs' peak impact.[9] As shown in **Figure 6**, electrification clearly raises the summer peak profile, though it does not significantly change the shape.

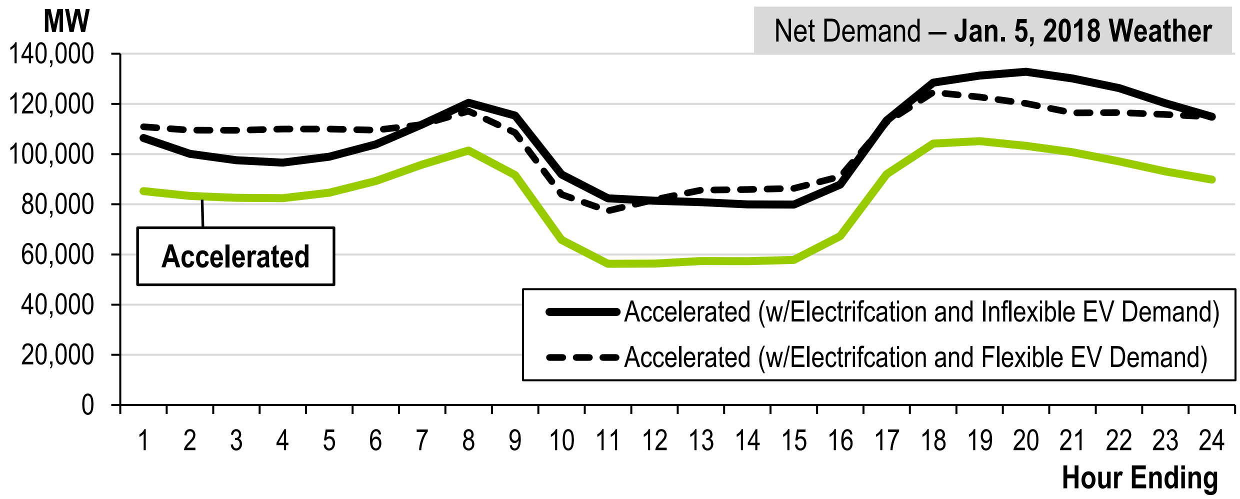
Figure 6. Summer Load Shape With Electrification



With electrification, the winter net-load hourly profile has a slightly higher, but substantially wider, peak demand than that of summer. Approximately 60% of the load-loss risk in winter is concentrated during the last four hours of the day. As shown in **Figure 7**, the net-load hourly profile is also considerably flatter in winter, spreading the remaining 40% risk across multiple hours of the day.

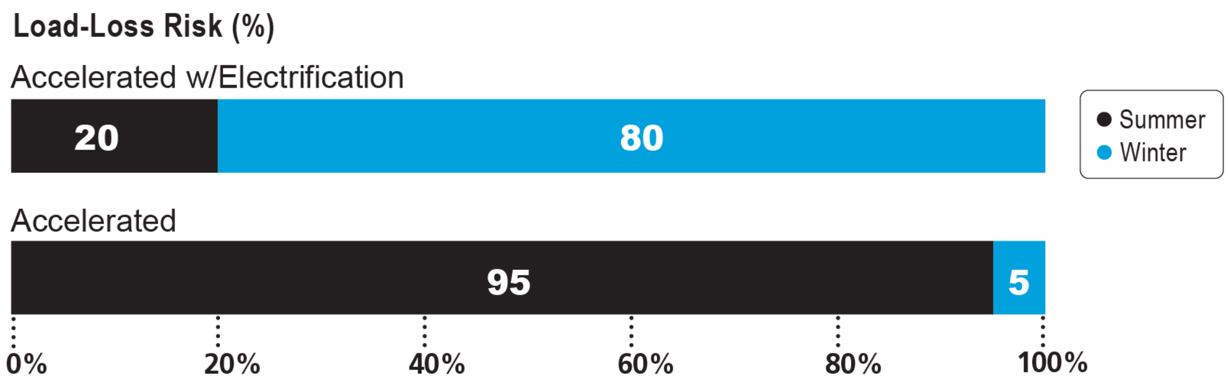
[9] Current EV charging behavior is informed by research done by ISO-NE (https://www.iso-ne.com/static-assets/documents/2021/04/final_2021_transp_elec_forecast.pdf). Achieving flexible EV demand is likely to be accomplished through time of use pricing to incent off-peak charging as some utilities within PJM have already started doing.

Figure 7. Winter Load Shape With Electrification



An additional consideration with electrification is that it creates new risk in winter, whereas status quo has the predominance of risk in the summer period. Traditionally, resource adequacy risk in the PJM footprint has been concentrated in the summer season. In the Accelerated scenario, 95% of the load-loss risk is experienced in the summer and the remaining 5% in winter. However, electrification – in particular heating – has an asymmetrical impact, with the demand growth in winter more than doubling that in summer (summer load growth is 7%; winter 15%). Consequently, there is a pronounced shift in both the seasonal and hourly risk profiles, forcing a new seasonal split of load-loss risk of 20% in summer and 80% in winter (see **Figure 8**). This would have implications on capacity requirements as well as resource value measured through the ELCC process.

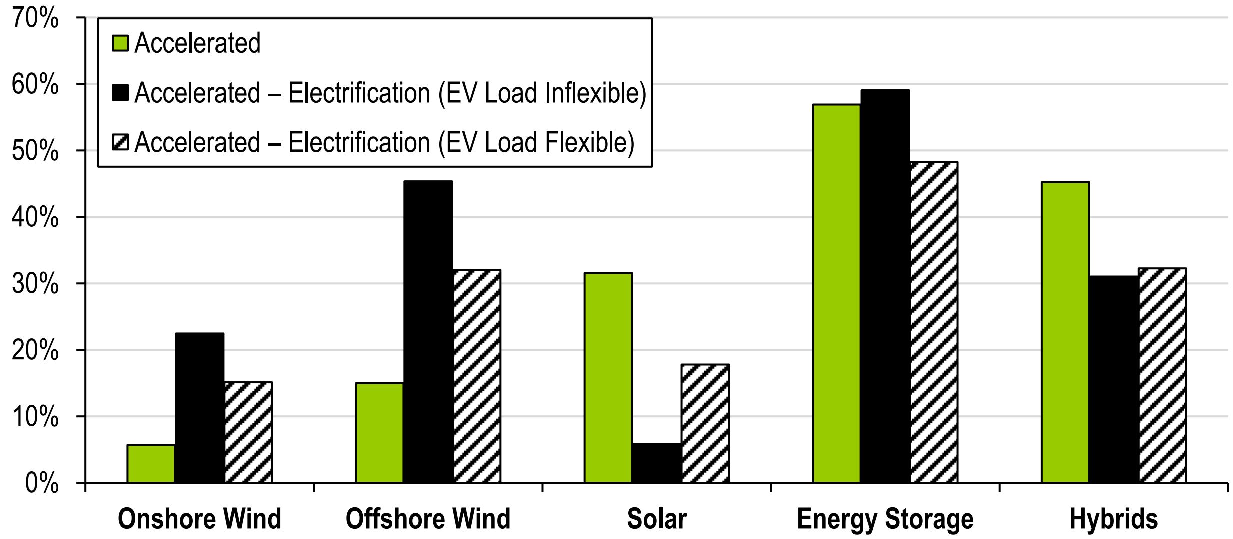
Figure 8. Seasonal Risk Shifts With Electrification



With electrification, resource adequacy risk shifts to winter.

Resources with higher winter outputs, like wind, have increased capacity values, as the impacts of electrification on load increase winter risk. For input portfolio development, this analysis assumed that the bulk hybrid resources added to the system are solar/storage; however, the impacts of electrification may incent development of more wind/battery hybrids.

Figure 9. Effective Load Carrying Capability Results by Resource Type – With Electrification



In general, as the penetration of a particular renewable resource increases, its capacity value contribution tends to decrease (see **Figure 9**). However, the ELCC methodology will produce different results depending on both the generation portfolio and load shape. As discussed above, electrification reshapes the load hourly profile, shifting the resource adequacy risk to winter. Assuming an inelastic demand behavior (i.e., electricity demand is insensitive to price), 60% of the load-loss risk is concentrated in the last four hours of the day, and, as a result, the capacity value of solar abruptly drops from 32% to 6%. Interestingly, the opposite trend is observed for wind resources, with a threefold increase in capacity value (onshore 6% to 22%; offshore 15% to 45%).

Retail rate design, to the extent it reshapes the load hourly profile, can change the load-loss risk profile and ELCC capacity accreditation to the benefit of renewable resources. For example, assuming that customers have access to real-time prices and customer-facing programs that incentivize EV charging in off-peak hours, the capacity value of solar with flexible EV demand increases from 6% to 18%. The net effect of retail rate designs that result in flexible demand is an overall reduction of the amount of capacity procured to meet the 1-in-10 LOLE reliability standard.

Resource Adequacy Implications

- Storage – Increasing solar penetration causes the number of high-load hours (within 5% of peak) to decline from seven hours in the Base scenario to just two hours in the Accelerated scenario. As a result, storage resources have a greater resource adequacy contribution in the Accelerated scenario because they can discharge stored energy over a shorter duration. In the Accelerated scenario, an additional 87% of nameplate capacity on top of the forecasted peak load was required to satisfy the 1-in-10 year LOLE. In a counterfactual scenario without storage, this requirement was 78%. Despite the fairly high ELCC value (about 60%) of storage, when storage displaces thermal resources, more nameplate storage is required, as the capacity contribution of thermal resources are higher than the ELCC value of storage; hence the increase in the nameplate requirement to integrate storage.

- Seasonal Risk Shifts – Electrification creates new risk in winter, whereas status quo has the predominance of risk in the summer period. This has implications on capacity requirements as well as resource value measured through the ELCC process. Resources with higher winter outputs, like wind, have increased capacity values as a result of higher winter risk due to electrification. Given the shift in resource adequacy risk to winter, it will be critical to explore the impact of common modes of failure that lead to correlated outages. PJM and stakeholders should explore the implications of a seasonal market product differentiation.
- Generation and Load Interaction – The complementary relationship of the generation portfolio and load shape has a profound impact on the ELCC capacity accreditation. Retail rate design that creates flexible demand reduces the amount of capacity procured and triples the capacity contribution of solar in the electrification sensitivity. It will be critical for PJM and stakeholders to continuously improve and incorporate sophisticated methods to accurately account for the capacity value contribution of all generation resources.

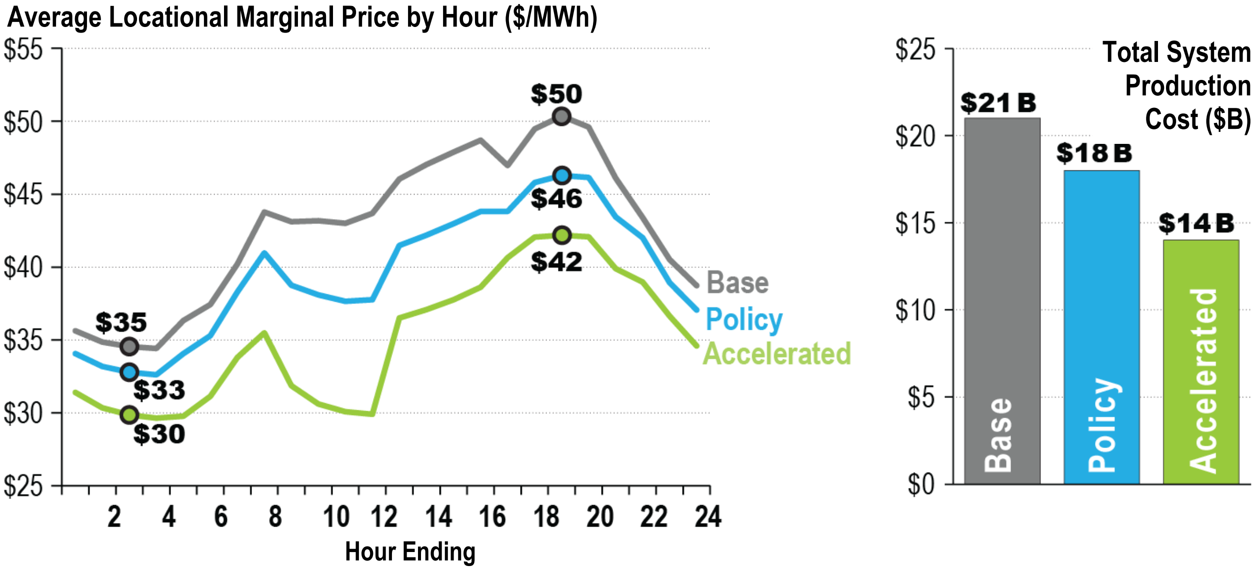
Energy & Ancillary Service Market Simulations

Utilizing a production cost simulation approach, Energy and ancillary services market products were implemented to explore the questions (Analysis Framework) related to downward-sloping Operating Reserve Demand Curve (ORDC), energy storage and electrification.

Locational Marginal Prices

Figure 10 shows the Energy Market dynamics. Across all hours, the average LMP decreases by 18% from the Base scenario to the Accelerated scenario with the highest penetration of renewables. The overall size of the Energy Market shrunk by about 35%, as measured in terms of total system production cost.

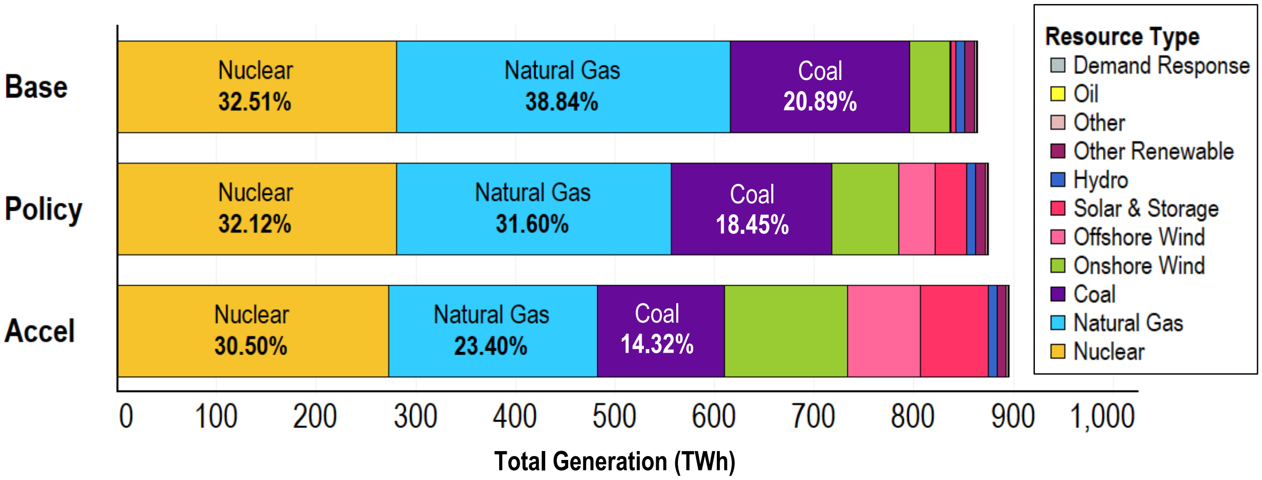
Figure 10. Energy Market Indicators



Generation Dispatch

Annual generation by fuel type for Base, Policy and Accelerated scenarios are shown in **Figure Figure 11**. Natural gas generation production decreased by about 40%, and coal generation production decreased by about 35% from the Base scenario to the Accelerated scenario. As a result, carbon dioxide emissions were reduced by about 40% in the Accelerated scenario compared to the Base scenario.

Figure 11. Annual Energy Generation by Fuel Type (TWh)



Operating Reserve Demand Curve (ORDC)

FERC has recently remanded PJM's proposal to incorporate a downward-sloping ORDC. PJM does not intend to rehash the ORDC proposal. However, the results of the study suggest that certain market reforms will be needed to address the rise in variability and uncertainty under high renewable penetration.

With higher renewable penetration levels, net-load (load minus renewables) forecast uncertainty increases. **Figure 12** shows the expected increase in synchronized reserve (SR) requirement to manage this uncertainty. The two-step ORDC curve is limited to addressing the reliability risk of losing the largest generator in the grid. The downward-sloping ORDC curve, on the other hand, is capable of addressing the reliability risk of the largest generator contingency, load forecast uncertainty and renewable forecast uncertainty.

Figure 13 shows that the hourly average SR price and procurement associated with the two-step ORDC curve is $0.02/MWh and about 2 GW, respectively, in the Accelerated scenario. As stated above, the downward-sloping ORDC, on the other hand, captures the additional reliability risk associated with the net-load forecast uncertainty and procures about 7.5 GW of SR on average at about $4/MWh in the Accelerated scenario. As a result, the two-step ORDC curve fails to capture significant quantity of risk that was observed in the downward-sloping ORDC curve in the Accelerated scenario with highest renewable penetration.

As shown in **Figure 12**, even with a much larger downward-sloping ORDC curve (to account for the greater uncertainty in the Accelerated scenario than that of the Base scenario), the study procured 150% more in SR quantity on average in the Accelerated scenario compared to the Base scenario (7.5 GW compared to 3 GW).This procurement also occurred at an average SR price that is about 35% lower in the Accelerated scenario compared to the Base scenario ($6/MWh compared to $4/MWh), as shown in **Figure 13**. This outcome demonstrates that a market mechanism (such as the downward-sloping ORDC curve) can be a cost-effective tool to incentivize necessary flexibility to manage increasing net-load forecast uncertainty associated with high penetration of renewables.

Figure 12. Two-Step and Downward-Sloping ORDC Curves

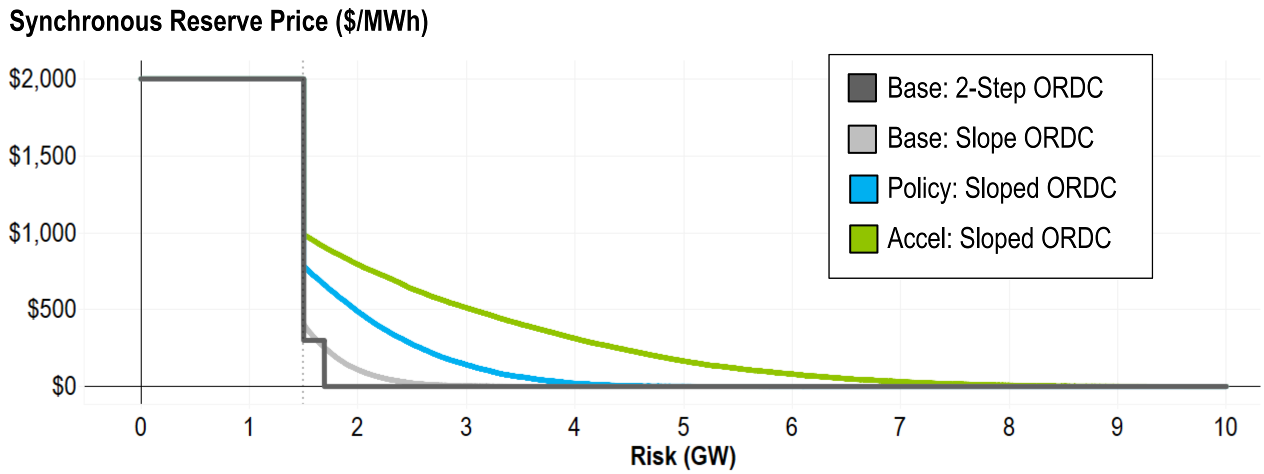
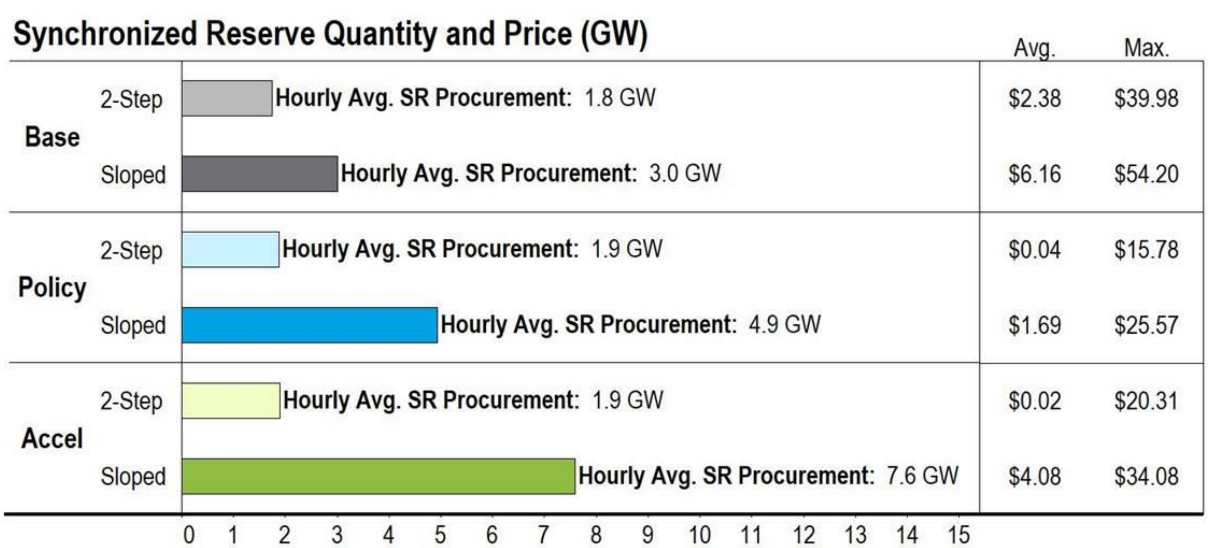


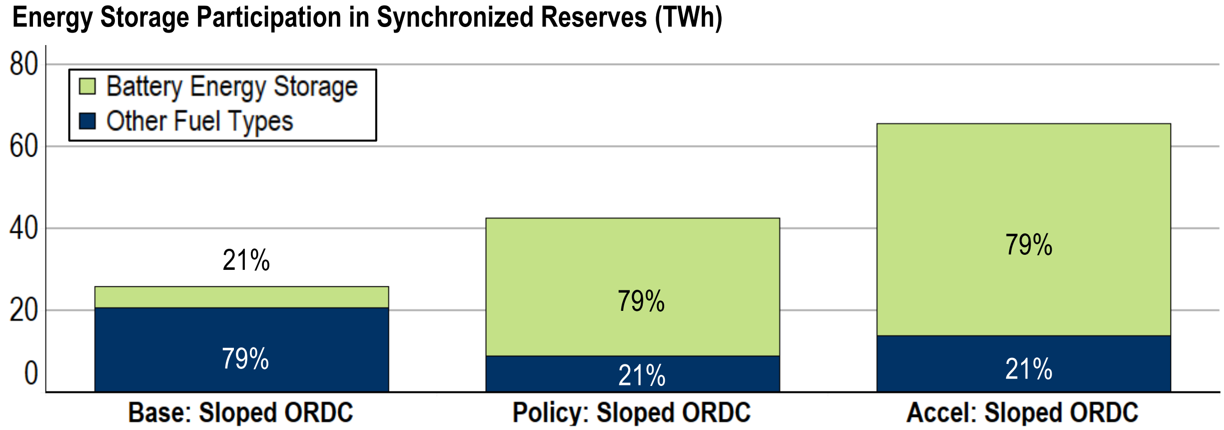
Figure 13. Two-Step and Downward-Sloping ORDC SR Procurement and Price



Energy Storage

Energy storage (battery) and hybrid (solar-battery hybrid) resources can provide greater flexibility to the grid. Batteries can cycle throughout the day, and hybrids can follow the load pattern to support power balance. Particularly, the benefit of this flexibility was observed in the downward-sloping ORDC SR procurement. **Figure 14** shows that the energy storage resources provided about 80% of SR provision in the Policy and Accelerated scenarios with higher penetration of storage. According to **Figure 13**, such flexibility was procured at an average SR clearing price that is 50% lower than the counterfactual scenario without storage ($4/MWh SR price in the Accelerated scenario with energy storage compared to $6/MWh in the Base scenario without energy storage), indicating economies of scale that could be attained as a result of implementing regional market reforms to incentivize flexibility.

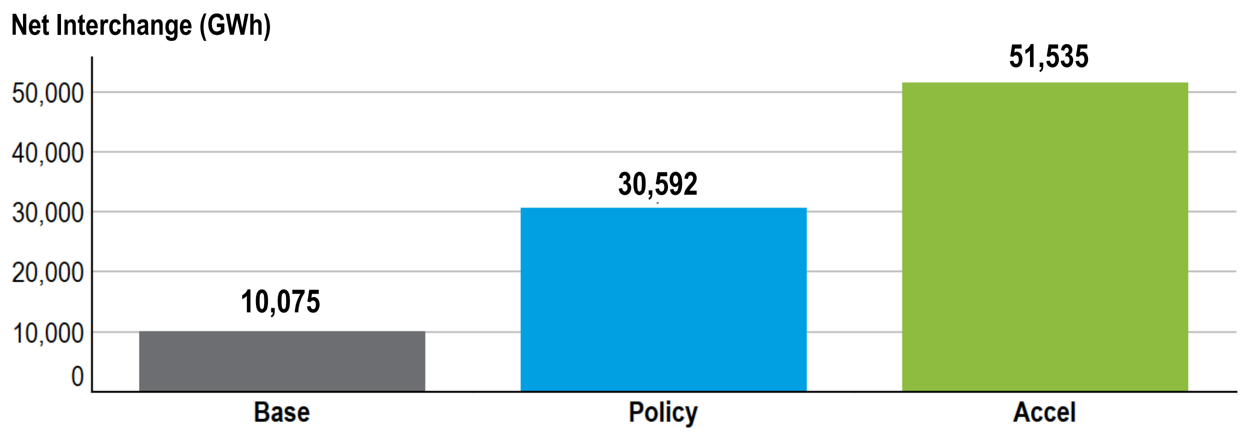
Figure 14. Energy Storage Participation in Synchronized Reserved



Interchange, Congestion, Renewable Generation Curtailments and Electrification

As shown in **Figure 15**, total annual net exports increased by a factor of five in the Accelerated scenario compared to the Base scenario. Congestion patterns across the PJM grid changed significantly. In the Accelerated scenario, the total congestion increased by about 60%.

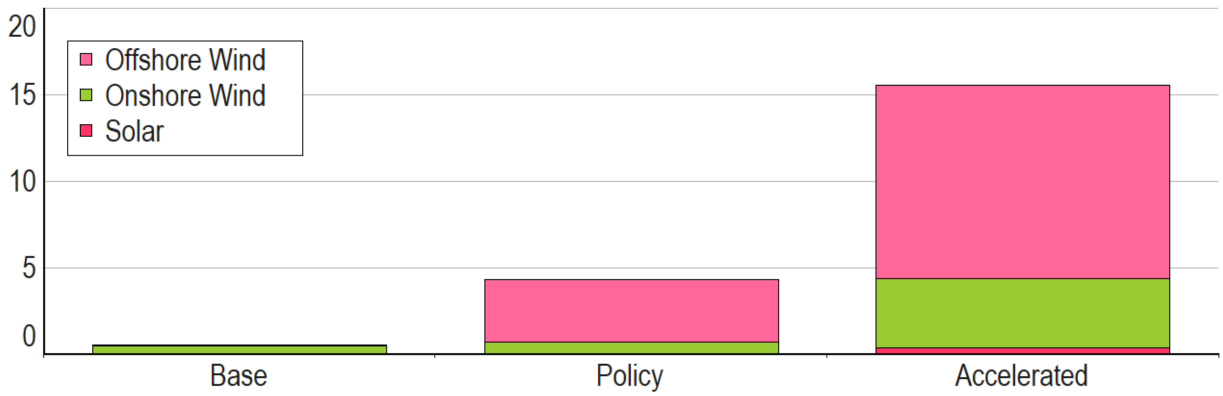
Figure 15. Total Annual Net Exports



As shown in **Figure 16**, the study revealed a significant amount of renewable generation curtailments (16% in the Accelerated case). Such curtailments were particularly exacerbated when high renewable generation experienced transmission bottlenecks (about 10% of the 16%), or during periods of low electricity demand where PJM had limited ability to export its excess renewable production. Exports were constrained when external regions also had excess renewable production (about 6% of the 16%).

Figure 16. Renewable Generation Curtailments

Renewable Curtailment (%) of Total Renewable Production



Despite the substantial integration of energy storage (37 GW of energy storage and 5 GW of pumped hydro adding up to 42 GW of storage), congestion and renewable curtailments were significantly increased indicating the need for a diverse set of solutions, including regional transmission expansion, long-term storage and emerging technology, to pursue a reliable and cost-efficient energy transition.

In an electrification sensitivity, average load demand went up by 7% in the summer and 15% in the winter in the Accelerated scenario. Even with the added demand, reliability was maintained, as no load shedding was observed. The average energy price went up by about 10%.

Ramping

The variability of renewable resources introduces ramping challenges. With higher penetration of renewables, both up and down net-load ramp (load ramp minus renewable ramp) increases significantly. **Figure 17** shows the total climb in net-load ramp on selected summer and winter days. This helps to illustrate the significant increase in net-load ramp (over 70 GW) and average ramping requirement (over 10 GW/hour in the winter) with higher renewable penetration.

Figure 17. Total Climb From Beginning to End of the Ramping Period for Selected Summer and Winter Days

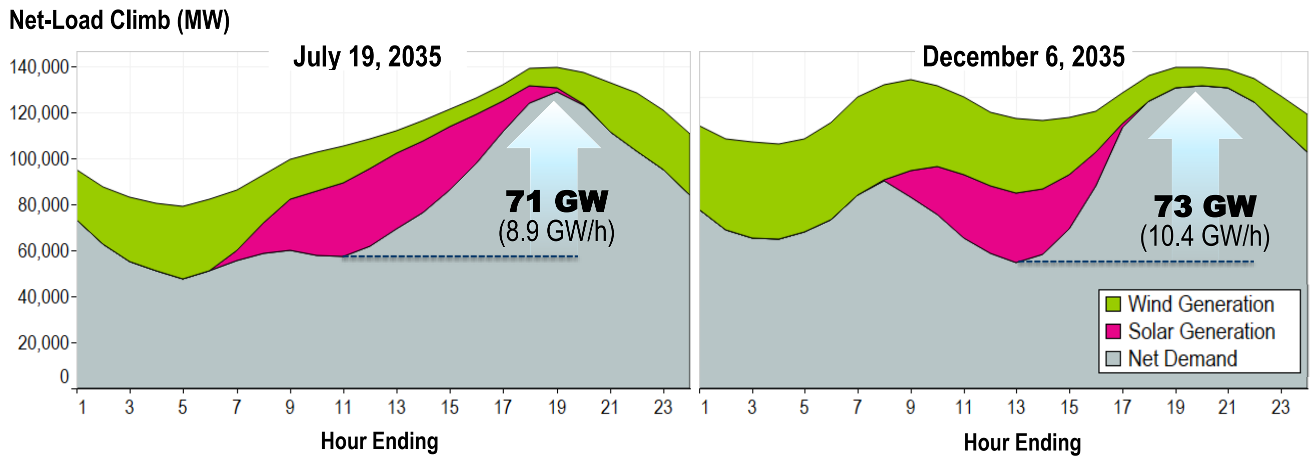


Table 2 and **Table 3** show descriptive ramping statistics for net load and native load for Base, Accelerated and Electrification scenarios. In the winter, the maximum net-load ramp-up requirement approximated 20 GW/hour (Accelerated scenario) – a 90% increase from the Base scenario. Winter net-load ramp consisted of about 50% native-load ramp (about 10 GW/hour) and about 50% renewable ramp (about 10 GW/hour). In the summer, the maximum net-load ramp up was about 17 GW/hour (Accelerated scenario) – a 50% increase from the Base scenario.

As the renewable penetration increases, the winter ramping needs begin to prevail. In the Base scenario, maximum net-load ramp is higher in the summer (11 GW/hour) than that of the winter (10 GW/hour); however, in the Accelerated scenario, maximum net-load ramp is higher in the winter (20 GW/hour) than that of the summer (17 GW/hour). Furthermore, the winter average ramp-up requirement increases by about 80% from the Base to Accelerated, while the summer average ramp-up requirement only increases by about 40% for Base to Accelerated. Therefore, higher operational flexibility will be necessary in the winter with greater renewable penetration.

From a ramp provision perspective, under high renewable penetration, thermal resources performed a critical role in maintaining reliability, typically supplying 50% of the ramping needs (42% gas, 8% coal). Hydro resources (including pumped storage) delivered 15% of the ramping needs. The contribution from hybrid resources, energy storage and regional interchange varied across the ramping period. Due to the limited duration of energy storage (four hours), the contribution of stand-alone batteries and solar-hybrid resources ranged from single digits to 40%. Regional interchange was inversely correlated to energy storage, acting as a buffer when storage was depleted and supplying 10% to 25% of the ramping needs.

Table 2. Net-Load (Load – Renewables) Ramping

Season/Scenario

Net-Load Ramp Stats (GW)		WINTER				SPRING				SUMMER				FALL			
		B	A	Accel +		B	A	Accel +		B	A	Accel +		B	A	Accel +	
				∩	※			∩	※			∩	※			∩	※
Up	Average	2.89	4.89	5.88	4.34	2.48	4.17	5.29	4.24	3.87	5.25	5.06	5.29	2.58	4.28	5.43	4.34
	Std. Deviation	2.37	4.00	4.72	3.87	1.99	3.32	3.84	3.25	2.20	3.43	3.38	3.53	2.08	3.26	3.67	3.32
	50th Percentile	2.33	3.90	4.83	3.19	1.98	3.33	4.48	3.63	3.80	5.23	4.78	5.08	2.05	3.47	5.00	3.64
	90th Percentile	6.13	11.01	13.05	10.39	5.41	9.23	10.96	8.82	6.75	9.73	9.84	10.08	5.44	9.15	10.27	9.13
	Max	10.09	19.11	23.61	19.86	11.12	19.83	19.95	19.90	11.05	16.90	15.82	19.08	10.52	17.10	17.56	17.06
	% Difference	**0%**	**69%**	**104%**	**50%**	**0%**	**68%**	**113%**	**71%**	**0%**	**36%**	**31%**	**37%**	**0%**	**66%**	**110%**	**68%**
Down	Average	2.42	4.21	5.06	3.99	2.53	3.91	4.91	3.92	4.44	4.73	5.45	4.43	2.87	3.81	4.70	3.96
	Std. Deviation	1.77	3.07	3.38	3.20	2.17	2.93	3.28	3.04	2.89	3.30	3.98	3.12	2.31	2.84	3.20	2.77
	50th Percentile	2.04	3.71	4.74	3.16	1.91	3.33	4.38	3.33	3.94	4.04	4.72	3.84	2.21	3.22	4.16	3.57
	90th Percentile	5.07	8.36	9.76	8.34	5.79	8.17	9.49	8.09	8.68	9.69	11.09	8.86	6.21	7.72	9.11	7.90
	Max	7.68	19.36	19.28	20.30	10.48	16.50	16.98	16.77	12.90	17.52	20.19	17.28	12.45	17.82	18.10	17.92
	% Difference	**0%**	**74%**	**109%**	**65%**	**0%**	**54%**	**94%**	**55%**	**0%**	**7%**	**23%**	**0%**	**0%**	**33%**	**64%**	**38%**

B = Base **A** = Accelerated **+** = With Electrification ∩= Inflexible ※= Flexible

Table 3. Native-Load Ramping

Season/Scenario

Native-Load Ramp Stats (GW)		WINTER				SPRING				SUMMER				FALL			
		B	A	Accel +		B	A	Accel +		B	A	Accel +		B	A	Accel +	
				∩	※			∩	※			∩	※			∩	※
Up	Average	2.92	2.97	3.66	2.18	2.50	2.55	3.46	2.35	3.74	3.31	3.87	3.79	2.67	2.60	3.53	2.71
	Std. Deviation	2.37	2.35	2.94	1.78	2.09	1.99	2.43	1.69	2.15	1.79	2.16	2.41	2.17	2.07	2.55	1.96
	50th Percentile	2.40	2.45	2.81	1.71	1.88	2.11	3.10	1.95	3.67	3.29	3.58	3.63	2.15	2.11	3.03	2.28
	90th Percentile	5.97	5.98	8.05	4.53	5.56	5.26	6.68	4.70	6.41	5.62	6.92	7.10	5.59	5.39	7.74	5.51
	Max	9.62	9.62	12.38	10.88	11.37	11.16	13.70	11.10	10.20	9.10	10.69	11.10	10.07	9.21	10.69	10.82
	% Difference	**0%**	**2%**	**25%**	**-25%**	**0%**	**2%**	**38%**	**-6%**	**0%**	**-11%**	**4%**	**1%**	**0%**	**-3%**	**32%**	**1%**
Down	Average	2.13	2.27	3.38	2.21	2.39	2.57	3.61	2.52	4.22	4.16	5.05	3.77	2.54	2.70	3.80	2.75
	Std. Deviation	1.57	1.65	2.44	1.75	1.92	1.97	2.79	1.98	2.70	2.78	3.48	2.69	2.11	2.09	2.79	2.15
	50th Percentile	1.78	1.96	2.87	1.88	1.88	2.14	2.93	2.10	3.84	3.66	4.29	3.21	1.95	2.20	3.16	2.33
	90th Percentile	4.53	4.73	6.99	4.58	5.27	5.39	7.61	5.15	8.20	8.27	10.13	7.64	5.54	5.63	7.81	5.63
	Max	6.65	7.90	12.85	10.06	10.07	10.07	13.39	13.18	11.55	11.55	13.66	14.03	12.25	12.25	14.53	14.36
	% Difference	**0%**	**7%**	**59%**	**4%**	**0%**	**7%**	**51%**	**6%**	**0%**	**-1%**	**20%**	**-11%**	**0%**	**6%**	**50%**	**8%**

B = Base **A** = Accelerated **+** = With Electrification ∩= Inflexible ※= Flexible

Moving Forward

This "living study" continues to represent PJM's tangible efforts to identify opportunities in the current market construct and offer insights into the future of market design, transmission planning and system operations. The findings in this paper should not be regarded as expected outcomes but as guideposts that will be refined as the study progresses. With that in mind, the following assumptions will be refined in the next phase of this multiyear effort:

Additional Sensitivities

- Accelerated generation retirement (coal and gas)
- Federal & state policies
- Renewable integration in the Eastern Interconnection

Exploring Market Design

- Participation of renewable resources in ancillary services
- Dispatchable renewable resources

Transmission Expansion

Transmission upgrades for system reliability and efficiency