Energy Transition in PJM:
Flexibility for the Future

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Contents

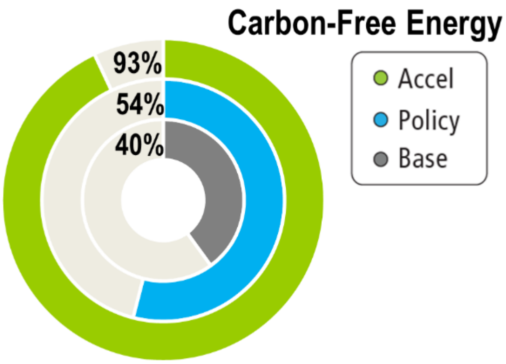
Executive Summary

In order to maintain reliability of the nation's bulk electrical system, PJM and the industry as a whole must understand the impact of a range of possible scenarios as the electric grid moves through the energy transition from a system based on thermal, dispatchable generation resources to one with increasingly more renewable, intermittent generation and storage.

This study is the fourth installment of PJM's multiphase effort to assess the impacts of renewable integration and is intended to continue to inform stakeholders and policymakers. The first two phases of the study focused on energy and ancillary services, essential reliability services, and impacts to Effective Load Carrying Capability (ELCC) in 2035 and beyond. The third phase focused on resource adequacy in the near term through 2030 and raised concerns about a mismatch between retirements, demand growth and the pace of new generation entry.[1]

This fourth phase shifts focus to the longer term to identify and examine the challenges that may arise if current state and federal energy policy goals are met or accelerated. Assumptions have been updated to represent the evolving system outlook for 2035, including modeling of retirements and the rate of renewable integration in neighboring regions and the resulting impact on regional interchange.

Refining Assumptions



The scenarios in this phase of the study represent updated assumptions to reflect evolving energy and environmental policies. This resulted in three scenarios – Base, Policy and Accelerated – with carbon-free generation[2] serving 40%, 54% and 93% of annual energy, increasing from 40%, 50% and 70% in the second phase (PDF) of the study.

The Base scenario provides a benchmark for today's system. The Policy scenario reflects existing state and federal policies coming to fruition by 2035. Retirements in the Policy scenario align closely with those reflected in the third phase of the study, Resource Retirements, Replacements & Risks (PDF). The Accelerated scenario aims to simulate a more stressed view of the system with generation expansion and retirement beyond existing policies. The models were also refined to better evaluate the interactions between PJM and the broader grid accounting for energy transition trends in neighboring regions.

[1] See Energy Transition in PJM: Frameworks for Analysis (PDF) | Addendum (2021) (PDF), Energy Transition in PJM: Emerging Characteristics of a Decarbonizing Grid (PDF) | Addendum (2022) (PDF), and Energy Transition in PJM: Resource Retirements, Replacements & Risks (PDF) | FAQ 2023 (PDF).

[2] Carbon-free generation includes wind, solar, storage, solar-storage hybrid, hydro and nuclear generation. Renewable generation excludes nuclear and stand-alone storage.

Findings

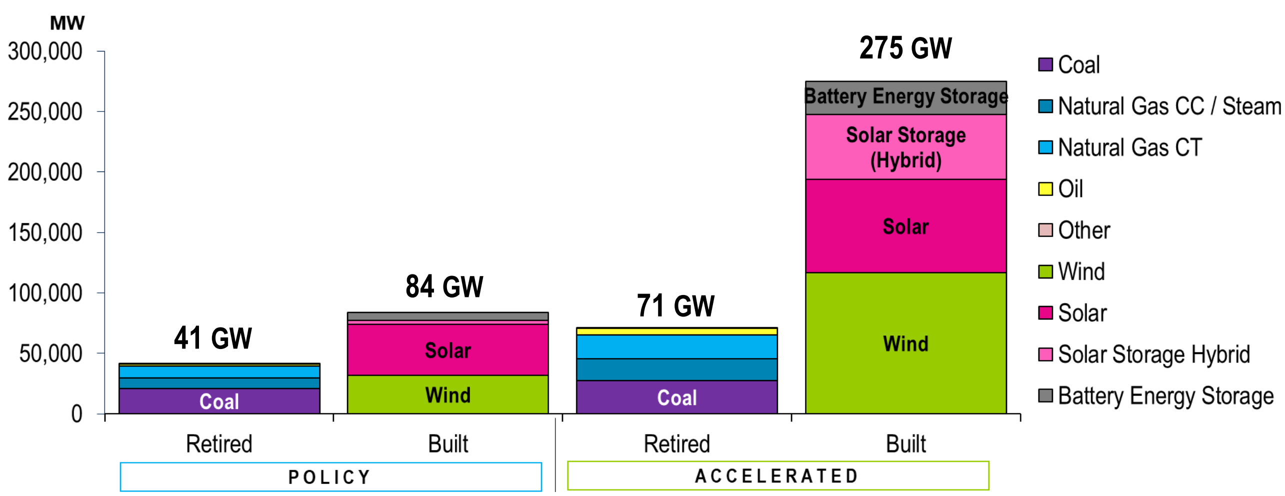
1 | Accelerating the Pace of New Entry Is Critical To Maintaining Reliability

PJM continues to track concerns raised in the previous phase of this study – that as demand growth and thermal resource retirements accelerate and the pace of development and deployment of new resources continue to lag and may result in a shortfall in supply by 2030.[3] The findings of this study add focus to system complexity anticipated beyond 2030, as unprecedented demand growth continues with the majority of the PJM interconnection queue made up of solar, wind, storage and hybrid resources.

In the Policy scenario, 41 GW of retiring generators (coal, natural gas and oil) are replaced by 84 GW (nameplate capacity) of new entry by wind, solar, storage and hybrids resources. This portfolio meets the various policy targets while maintaining resource adequacy [one-in-10 loss-of-load expectation (LOLE)]. The Accelerated scenario extends the level of retirements to 71 GW, requiring a significantly larger 275 GW of buildout of renewable and storage.

Moving from the Policy to the Accelerated portfolio in **Figure 1**, less than doubling the amount of resource retirements results in a quadrupling of the amount of new entry needed to maintain the same level of resource adequacy. Despite 275 GW of renewables and storage being built in the Accelerated scenario, 79 GW of flexible thermal resources are still needed to maintain resource adequacy at one-in-10 LOLE. This highlights that substituting thermal resources with renewable generation may get significantly more challenging as the energy transition progresses.

Figure 1. Increasing Capacity Additions Needed To Replace Retirements



The demand in each scenario reflects growth from end-use electrification, electric vehicles and data centers. Recent history of this anticipated growth has proven unprecedented and dynamic. Average growth estimates for PJM's summer peak, for example, have increased by 375% between the 2022 and 2024 load forecasts – from 0.4% per year to 1.6% per year. This trend adds to the complexity of ensuring reliability through the energy transition.

[3] Energy Transition in PJM: Resource Retirements, Replacements & Risks (PDF) | FAQ 2023 (PDF)

2 | Interregional Transfer Capability Is Increasingly Important

Increasing amounts of intermittent wind, solar and storage resources will change today's interactions between neighboring systems and raise new questions about the ability to lean on each other during times of system stress. To assess this, thermal retirements and renewable integration were reflected in PJM's neighboring regions alongside the trends in PJM. In the Accelerated scenario, PJM's neighbors have a total of 375 GW of wind, solar and storage, with coal, natural gas and oil down to 120 GW total.

The Policy scenario showed that adequate transfer capability exists to facilitate the renewable integration considering current state and federal policies. The large interfaces to the west were not constrained, while interfaces to the north and south bound less than 30% of the time. As the resource mix changes more substantially in the Accelerated scenario, interface limits are reached more often. As PJM and its neighbors look ahead to existing policies coming to fruition, focus must be placed not just on total transfer capability available, but on how well that existing capability is being managed and coordinated.

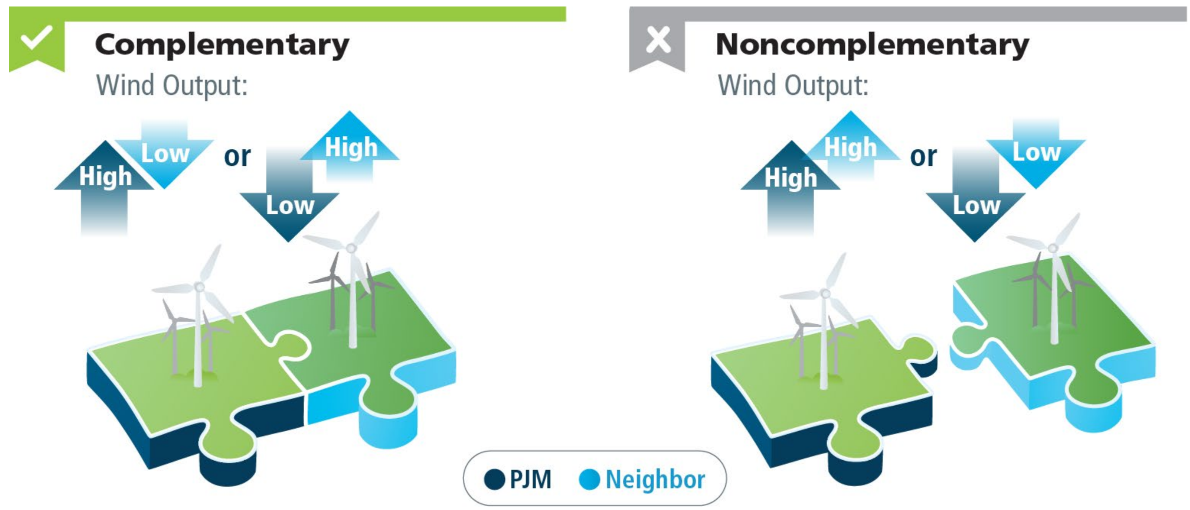
The ability to continue to rely on and support neighbors will require increased coordination to manage a new range of extremes with respect to interchange variability. The study shows an increase in total interchange between PJM and its neighbors of 35% between the Base and Accelerated scenarios. In addition, the Accelerated scenario shows periods where PJM goes from exporting to importing 10 GW or more in small time frames. This variability is driven by increases in intermittent generation, particularly wind.

In general, the varying renewable output between PJM and its neighbors is complementary. Conceptualized in **Figure 2**, this occurs when renewable output is low in one region and other regions are experiencing higher output. Complementary behavior occurs in 83% of hours in the Accelerated scenario and can benefit each region's needs for balancing and ramping. For example, in the Accelerated scenario, interchange contributes to 15% of PJM's ramping needs. However, coincidental peaks and valleys of wind output across systems will challenge interchange and will require flexibility among generating resources. In the Accelerated scenario, PJM and MISO experience low wind generation output at the same time in 9% of hours and high wind generation 8% of the time.[4] When both entities experience the same set of extreme conditions, the ability to lean on neighbors may not be an option for grid operators. This increased reliance across the Eastern Interconnection demonstrates the need for enhanced coordination and dovetails with efforts already underway between PJM and MISO.[5]

[4] Intervals with wind generation below its seasonal 25th percentile are classified as "Low-Wind." "High-Wind is classified as generation above the 75th percentile.

[5] Two Major Grid Operators Embark on Joint Planning Endeavor To Enhance Reliability (PDF)

Figure 2. Managing Renewable Generation Uncertainty With Neighbors



3 | Multiday, Dispatchable Resources Are Needed

Increasing levels of intermittent resources create significant variability and uncertainty to be managed by flexible resources. In the Accelerated scenario, renewable generation instantaneously represented as much as 118% of the RTO load (with exports) and as little as 3% of the RTO load. The net load ramp over a three-hour period maxed out at 105 GW, which is greater than the peak load of the entire ERCOT system. The total system ramping needs are met by energy storage (43%), thermal resources (32%), interchange (15%) and hydro (7%).

From the Base to Policy scenario, natural gas resource capacity factors increase to manage thermal retirements. Moving into the Accelerated scenario, natural gas utilization decreases as the combined cycles operate as flexible peakers rather than baseload. Adding to the complexity, the need for flexible resources, in particular to meet ramping needs, varies drastically by season. Average capacity factors of the combined cycle fleet range from 5% in April to 45% in July.

Periods of low thermal fleet utilization are coupled with extended periods of time when demand is met by zero- or low-cost resources. Natural gas energy revenues decreased 54% across the year between the Base and Accelerated cases, ranging from a 39% decline in the winter to a 91% drop in the spring. Additionally, large amounts of storage are assumed to be built to meet system ramping needs.

If the gas fleet of today remains as is, or decreases due to regulatory pressures, but additional storage resources do not get built at pace, immense pressure will be placed on natural gas to supply the ramping needs for the system. Changes to market mechanisms should be evaluated to ensure that adequate resources are incentivized to help PJM manage increasing system uncertainty and volatility.

Background

The PJM electrical grid, spanning 13 states and Washington, D.C., has been keeping the lights on for its customers for nearly a century. The region's generation fleet is undergoing a historic transformation to more renewable energy sources and storage from a system based on thermal, dispatchable generation resources. As such, PJM is focused on ensuring a reliable energy transition and is working with its stakeholders throughout the energy industry to smooth the way for the transition by evolving market rules, streamlining the planning process for new generators, and engaging with federal agencies and states to put energy policies into action.

As part of this, PJM has been conducting research and analysis to identify opportunities and challenges associated with the energy transition. This study is the fourth phase of PJM's multiyear initiative to assess the impacts of renewable integration.

Scenario Development

The scenarios in this study reflect updated assumptions, including increasing levels of potential generation retirements and evolving policies advancing large amounts of renewables, storage resources and cross-sector electrification. The models were also refined to better analyze the complementary behavior between PJM and neighboring regions, accounting for the evolving resource mix in all regions. **Table 1** highlights the key features of each scenario.

The Base case scenario reflects the system as it is today. The Policy scenario represents outcomes as expected by 2035 under existing state and federal energy policies. The Accelerated scenario serves as a high-end level of both generator retirements and an introduction of renewable generation and storage resources.

Table 1. Scenario Summary

	Base	Policy	Accelerated
Purpose	Provide benchmark for today's system, aligned with 2022 RTEP case.	Evaluate system impacts of state and federal policies implemented by 2035.[6]	Evaluate system impacts of an accelerated pace of resource expansion, retirement and electrification.[7]
Supply[8]	8% renewable 40% carbon-free	22% renewable 54% carbon-free	61% renewable 93% carbon-free
Retirements	Announced deactivations[9]	41 GW of anticipated coal, natural gas and oil retirements due to state and federal policies by 2035	71 GW total; retirements beyond Policy scenario to keep system at minimum reserve margin (1-in-10 LOLE) while adding large amounts of renewables and storage
Demand	2022 PJM load forecast for 2035[10] 9 GW BTM solar 900 thousand electric vehicles	2022 PJM load forecast for 2035[10] 19 GW BTM solar 7.6 million electric vehicles	2022 long-term load forecast for the year 2035 with accelerated electrification[10] 30 GW BTM solar 17 million electric vehicles

While implementing retirement and replacement assumptions, PJM analyzed the portfolio composition needed for the Policy and Accelerated scenarios to maintain the minimum level of resource adequacy, defined by having an LOLE at one in 10[11] and accounting for portfolio-dependent capacity values of resources defined via ELCC.[12] Reserve levels today ensure an LOLE that is more reliable than one day in 10 years. For the purposes of the Policy and Accelerated scenario studies, PJM set the reserve levels at the one-day-in-10-year LOLE criterion to provide a lower bound on the Installed Reserve Margin (IRM) level. The analysis in this study revealed that policy-driven deactivations brought the Policy scenario to this lower bound. In the Accelerated scenario, it would take an additional 30 GW of deactivations, given the level of generation added under the scenario, to reduce the reliability level to the minimum one-day-in-10-year LOLE.

[6] These policies include state clean energy targets, renewable portfolio standards, individual technology targets for offshore wind and energy storage, and environmental regulations affecting thermal resources.

[7] The IHS Power Market Outlook (June 2022) with expansion through 2050 was utilized to create the Accelerated resource expansion scenario.

[8] Percent of energy serving demand

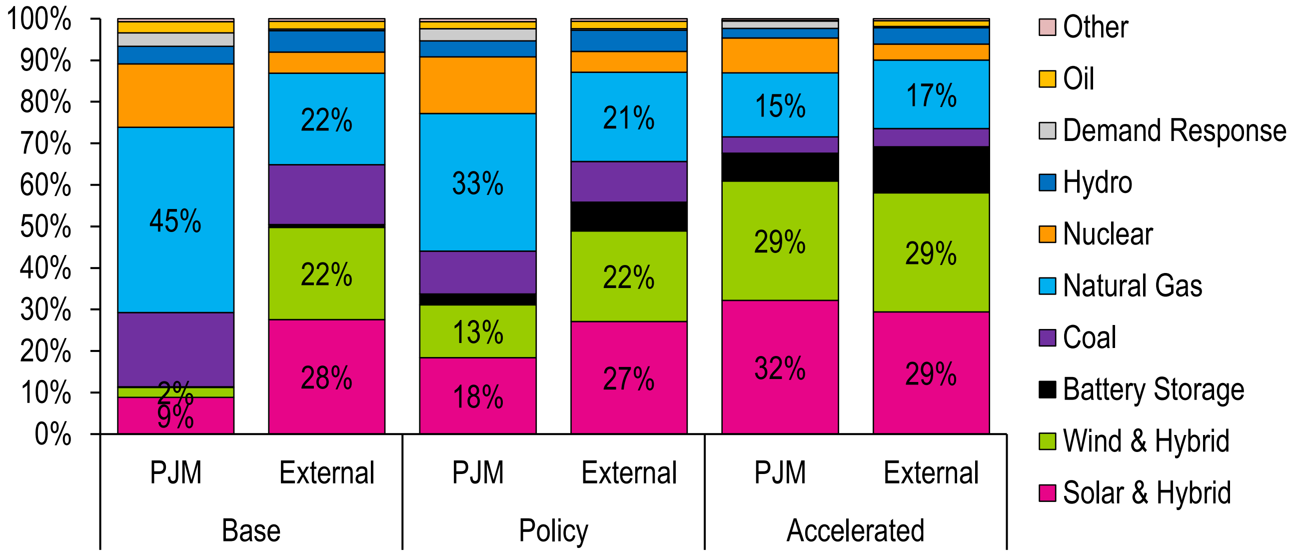
[9] PJM – Generation Deactivations

[10] Data center demand is included in load forecast.

The transmission system from the 2022 RTEP case was the baseline for the analysis. Line rating updates to existing transmission lines were made to address thermal violations in the Policy and Accelerated scenarios. Interchange was allowed up to existing tie limits in all scenarios. The PJM system was simulated for an entire year at an hourly resolution.

Thermal retirements and renewable integration were also reflected in PJM's neighboring regions. **Figure 3** summarizes the resource mixes as a percentage of total installed capacity in PJM and neighboring regions. In the Accelerated scenario, PJM neighbors have a total 375 GW of wind, solar and storage, with coal, natural gas and oil down to 120 GW total.

Figure 3. Percent of Total Installed Capacity in PJM and Neighbors



[11] 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).

[12] 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 be approximately 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).

Table 2 summarizes the assumptions developed for this analysis and highlights key differences from previous phases of the study as it has evolved.

Table 2. Study Phase Comparison

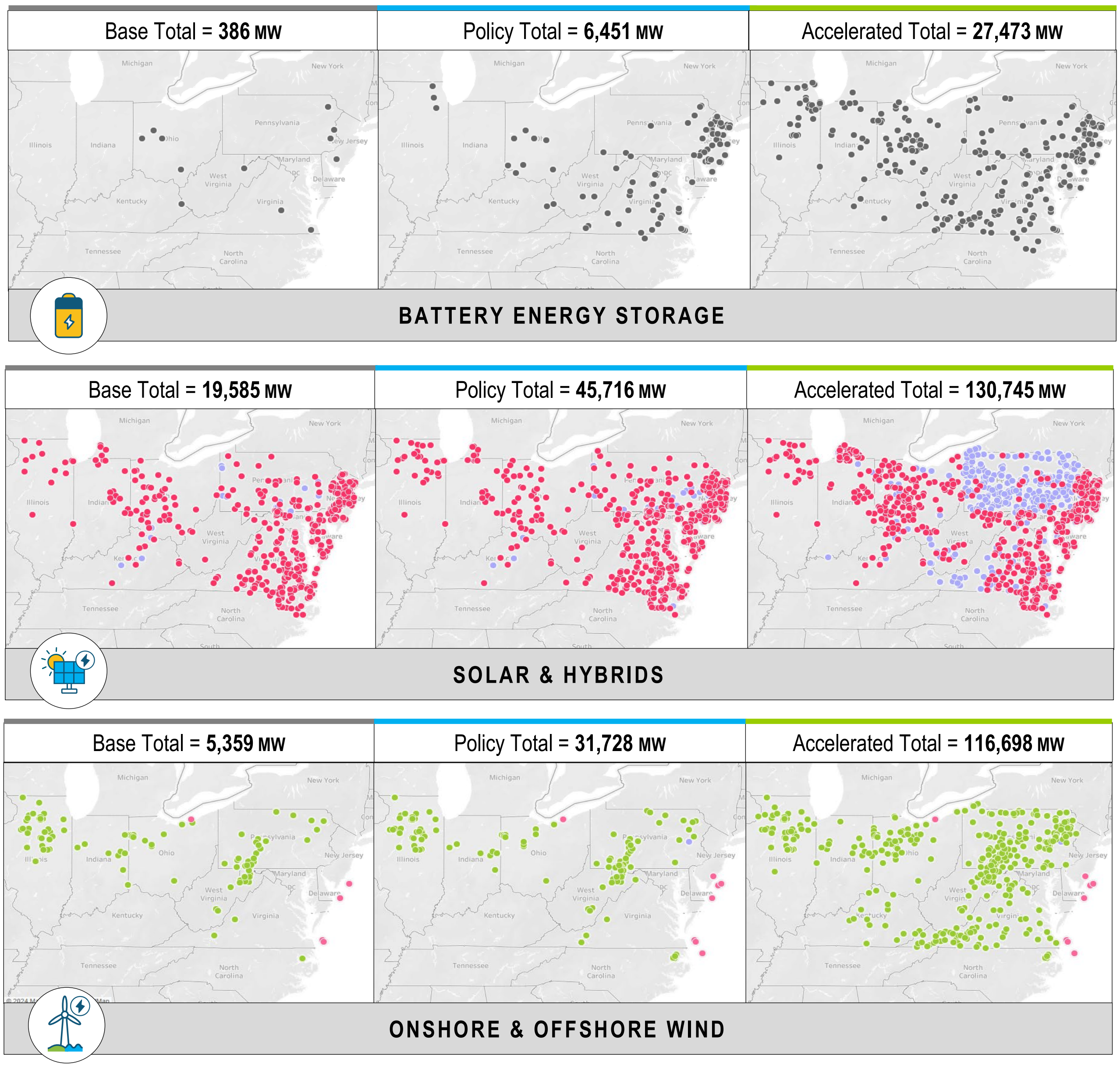
Phase 1 (2021)	Phase 2 (2022)	Phase 3 (2023)	Current Phase
ANALYSIS FOCUS			
Energy & ancillary services, essential reliability services, and impacts on Effective Load Carrying Capability (ELCC)	Phase 1 approach with increased focus on energy storage, electrification and reserve market design, and refreshed scenario assumptions	Resource mix "balance sheet" as defined by generation retirements, demand growth and new generation	Updated policy assumptions, complementarity between resources in PJM and neighbors and interregional impacts, and seasonality effects
TIME HORIZON			
2035+	2035+	2022–2030	2035+
RENEWABLE & ENERGY STORAGE RESOURCES			
UP TO: •29 GW offshore wind •36 GW onshore wind •55 GW solar •Pumped storage only	UP TO: •29 GW offshore wind •36 GW onshore wind •21 GW solar •65 GW solar/storage hybrid •6 GW of stand-alone storage •Existing pump storage	•Low New Entry by 2030: 48 GW-nameplate/8 GW-capacity wind and solar; 3 GW storage •High New Entry by 2030: 94 GW-nameplate/17 GW-capacity wind and solar; 4 GW storage	UP TO: •15 GW offshore wind •101 GW onshore wind •77 GW solar •53 GW solar/storage hybrid •27 GW of stand-alone storage •Existing pump storage
RETIREMENTS			
UP TO: Natural gas – 0 GW Coal – 8 GW | Oil – 0 GW	UP TO: Natural gas – 0 GW Coal – 9 GW | Oil – 0 GW	BY 2030: Natural gas –12 GW Coal – 24 GW | Oil – 4 GW	UP TO: Natural gas – 38 GW Coal – 27 GW | Oil – 5 GW
INTERCHANGE			
Interchange allowed up to tie limits	Available transfer capability artificially limited to historical levels	N/A	Interchange allowed up to tie limits
LOAD			
2020 long-term load forecast for the year 2035 (all scenarios) Summer peak: 160 GW	2021 long-term load forecast for the year 2035 and electrification sensitivities Summer peak: 155 GW	2023 long-term load forecast through 2030 Summer peak: 156 GW	2022 long-term load forecast for the year 2035 with accelerated electrification Summer peak: 170 GW
SYNCHRONOUS RESERVES			
Two-step ORDC	Downward-sloping ORDC renewable variability impacts the reserve requirement	N/A	Two-step ORDC

Findings

Accelerating the Pace of New Entry Is Critical To Maintaining Reliability

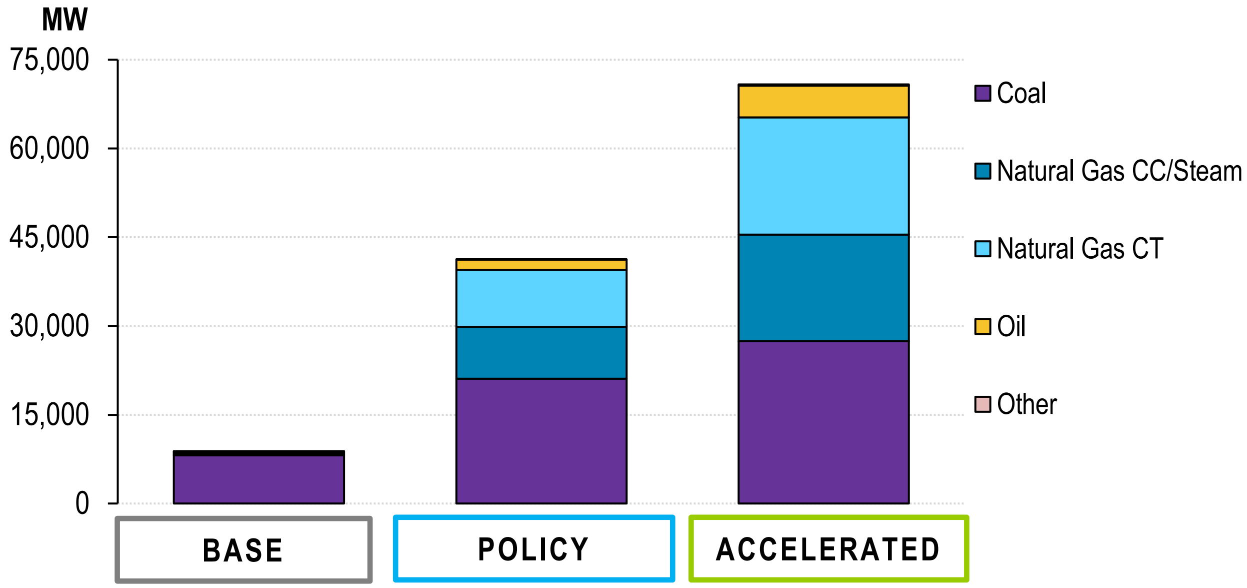
In the near term, the pace of development of resources to replace thermal retirements while maintaining reliability must continue to be a focus. Because the future system will likely be powered by a largely intermittent and inverter-based fleet, system complexity will only increase with these developments. The buildout of new generation assumed in each scenario is mapped across the RTO in **Figure 4**.

Figure 4. Renewables and Storage Buildout by Scenario



Assumed retirements by resource type are shown in **Figure 5.** Even with this large volume of retirements, the Accelerated scenario still needed 63 GW of natural gas, 16 GW of coal, 700 MW of oil. The existing nuclear fleet was also assumed to be maintained at 34 GW.

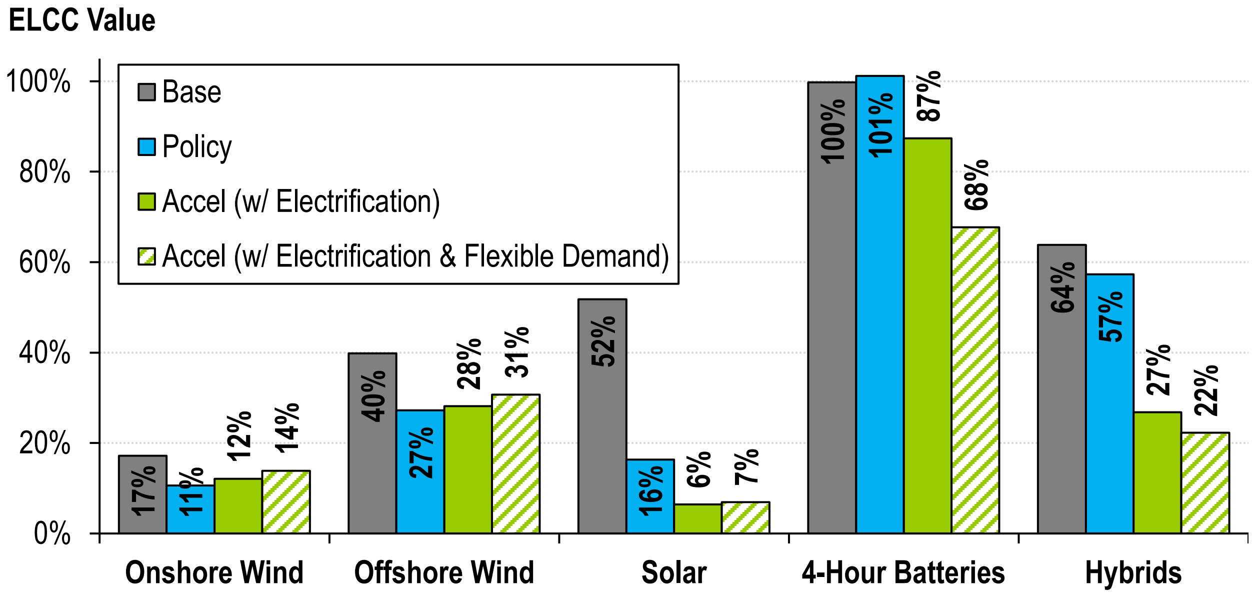
Figure 5. Retirements by Scenario



The demand in each scenario reflects growth from end-use electrification, electric vehicles and data centers. Recent history of this anticipated growth has proven unprecedented and dynamic. Although the 2022 load forecast was utilized as a the starting point for demand in this study, the peak demand studied in the Accelerated scenario is now in line with the most updated 2024 load forecast – with a summer peak of about 170 GW. Average growth estimates for PJM's summer peak, for example, have increased by 375% between the 2022 and 2024 load forecasts – from 0.4% per year to 1.6% per year. This trend adds to the complexity of ensuring reliability through the energy transition.

Between the Policy and Accelerated scenarios, less than doubling the amount of resource retirements results in a quadrupling of the amount of new entry needed to maintain the same level of resource adequacy. This is due in part to the capacity value each resource type, which is influenced by a number of factors: load shape, resource profile shape and variance, resource limitations, amount of resources and complementarity with other resources. Capacity value will be a function of not only how it aligns with load, but also how the resource has an impact on net demand. Net demand is the load that must be served minus that resource and others like it that may all change output at the same time based on weather conditions, as with solar and wind. **Figure 6** highlights the change in capacity value for each resource type by scenario.

Figure 6. Effective Load Carrying Capability Progression by Resource Type



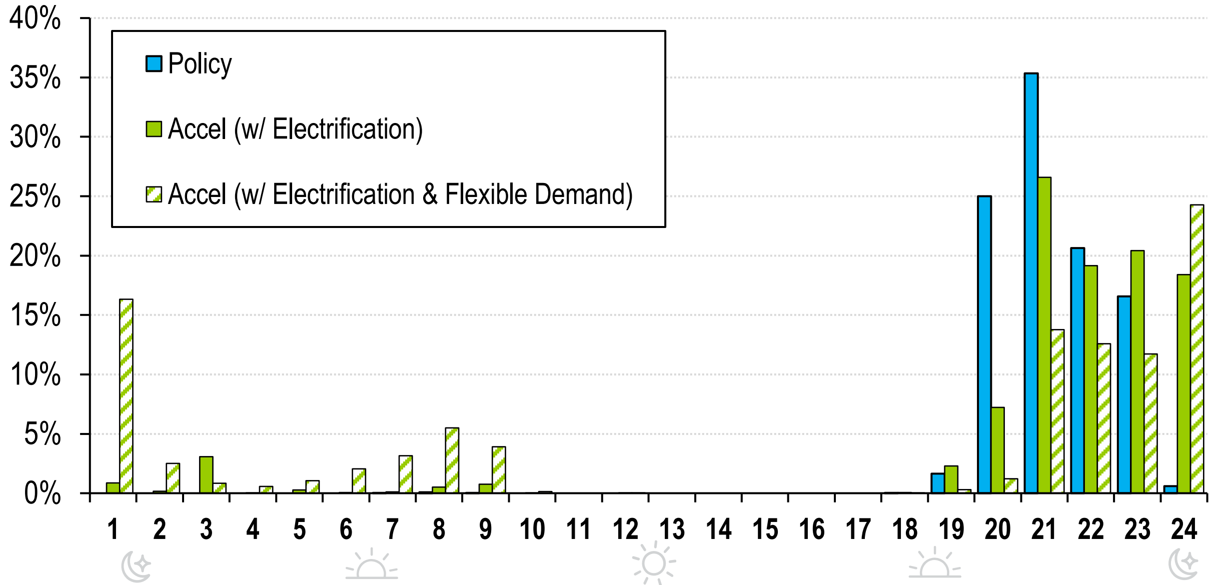
The ELCC analysis utilized in this study is consistent with the methodology from the December 2022 ELCC Report, which included updates to offshore wind shapes and storage dispatch assumptions.[13] The newest ELCC methodology approved by FERC on Jan. 30, 2024, was not included in this analysis.[14] The new method would capture additional winter risk above what is shown in these results, and the capacity values of storage and thermal resources would decrease.[15] This would result in the need for even more intermittent resources to be built to satisfy the system's minimum reserve requirement in the Policy and Accelerated scenarios.

Increasing amounts of solar push net demand, and consequently risk, into later hours, as observed in the increasingly common "duck curve." Progressively lower solar output during the later high-risk hours diminishes solar's ELCC value. Even when electrification with a level of flexible demand spreads out that risk, the results in this phase of the study do not show a rebound in capacity value as they did in the 2022 study due to the increased amounts of stand-alone solar compared to solar hybrids.

Energy storage provides reliability value through shifting net demand by charging when demand is low and discharging when demand is high. This matches well with peaky-demand shapes like those in the summer with risk very concentrated, and thus storage is able to reliably serve the peak. **Figure 7** highlights how risk spreads to different hours between scenarios. Energy storage maintains its full value in the Policy scenario, while in the Accelerated scenarios, risk spreads out with increased renewables, storage and electrification demand. Specifically, the extension of risk beyond the contiguous hours of concentrated risk in the Policy scenario reduces the ELCC value of four-hour storage. Though not tested in this analysis, longer duration energy storage, such as 10-hour batteries, may have retained full capacity value in the Accelerated scenario, as risk is largely contained to five contiguous hours.

[13] December 2022 ELCC Report (PDF)
[14] FERC ELCC Methodology
[15] Capacity Values of Storage and Thermal Resources (PDF)

Figure 7. Share of Loss-of-Load Hours for Policy and Accelerated Scenarios



The electrification load adds additional electric vehicles (EVs) as well as additional electric heating, water heating and cooking. For EVs, two shapes are considered to highlight the potential impact of flexible demand: status quo charging and levelized charging. Status quo charging approximates the manner in which EVs are charged currently, which results in a larger increase in peak profile from the original load forecast. The levelized charging scenario assumes that charging will move toward overnight hours and somewhat more in the midday and thus lessen EVs' peak impact.[16]

Additional electric heating will increase winter demand and create new risk in winter, whereas traditionally the predominance of risk is in the summer period. In the Accelerated scenario, 98% of the load-loss risk is experienced in the summer and the remaining 2% in winter. The modeled electrification scenario[17] shifts a significant amount of risk into the winter such that risk becomes approximately two-thirds summer risk and one-third winter risk. Spreading of risk to the winter impacts resource value, increasing the value of wind and offshore wind while decreasing the value of solar.

[16] This is more in line with PJM's current forecasting approach. The Policy and Accelerated scenario both assume this charging pattern, and the 2023 Load Forecast assumes that charging will move toward levelized charging in the long run.

[17] The modeled electrification scenario is described earlier in the document and represents a sensitivity. Realized electrification could reasonably be expected to be higher or lower, and those assumptions would impact the results described here.

Energy storage would seemingly benefit from an electrification scenario in which EVs charge heavily at peak. This is because this scenario would heavily concentrate risk. Under the status quo charging scenario, 85% of loss-of-load hours would occur in the last four hours of the day. By comparison, 62% of loss-of-load hours are concentrated in the last four hours of the day in the levelized EV charging scenario, with more risk spreading into the overnight and some winter morning hours. This illustrates how EV charging decisions may create trade-offs. While demand flexibility can reduce total peak resource needs, it may also affect resource value such as storage.

Also notable is that midday has no hours of load-loss risk. This is because there is both high solar resource availability and low natural demand. This provides abundant headroom to charge energy storage during this period; however, it also may result in excess generation.[18] This could potentially be an area for demand flexibility to provide additional reliability value by pulling some of the demand in the high-risk evening hours forward.

PJM continues to track concerns raised in the previous phase of this study – that as demand growth and thermal resource retirements accelerate and the pace of development and deployment of new resources continue to lag and may result in a shortfall in supply by 2030.[19] The findings of this study add focus to system complexity anticipated beyond 2030, as unprecedented demand growth continues with the majority of the PJM interconnection queue made up of solar, wind, storage and hybrid resources.

[18] Roughly 3–4% of hours in the electrification scenario had potential renewable generation in excess of that needed by demand plus what could possibly be used to charge grid-level energy storage.

[19] Energy Transition in PJM: Resource Retirements, Replacements & Risks (PDF) | FAQ 2023 (PDF)

Interregional Transfer Capability Is Increasingly Important

In today's system, a diversity of resources across the Eastern Interconnection allows for PJM and its neighbors to coordinate and exchange power day-to-day and during times of extremes. The evolving system, with large amounts of renewable resources and diminishing thermal fleets, raises questions about today's paradigm of interregional coordination. Specifically, will renewable integration produce an Eastern Interconnection that is either more or less complementary than today? Is enhanced transfer capability needed to maintain reliability across systems?

Intermittent resource variability demands increased coordination between interconnected systems. For example, while solar output generally follows the hours of sunlight (not withstanding cloud coverage), wind patterns can vary throughout different portions of the day. Coincidental peaks and valleys of wind output within and outside of the PJM footprint will challenge interchange between the systems and underscores the need for flexibility within the generation fleet. Within the study period, PJM and MISO had coincidental low wind generation output 9% of the time and coincidental high wind generation 21% of the time.[20]

As part of the broader Eastern Interconnection, PJM recognizes the importance of continued coordination with neighboring regions in terms of system reliability and market efficiency. As intermittent resources increase throughout these regions, total interchange across the RTO and at specific interfaces varies across the scenarios run in this study. Highlighted in **Figure 8** the strong interface with MISO (+16 GW) effectively managed the renewable generation portfolio in both scenarios. Given the relatively lower transfer capability of CPLW, CPLE and NYISO (2 GW–3 GW), interchange was bound by the transfer limit in accordance with **Table 3**. The study showed that with current thresholds, PJM has sufficient interchange transfer capability to address both Base- and Policy-level renewable penetration. The Accelerated scenario shows some increases in the number of hours at transfer limits. As PJM and its neighbors look ahead to existing policies coming to fruition, focus must be placed not just on total transfer capability available, but on how well that existing capability is being managed and coordinated.

[20] Intervals with wind generation below its seasonal 25th percentile are classified as "Low-Wind." "High-Wind is classified as generation above the 75th percentile.

Figure 8. MISO Interchange Across Studied Scenarios

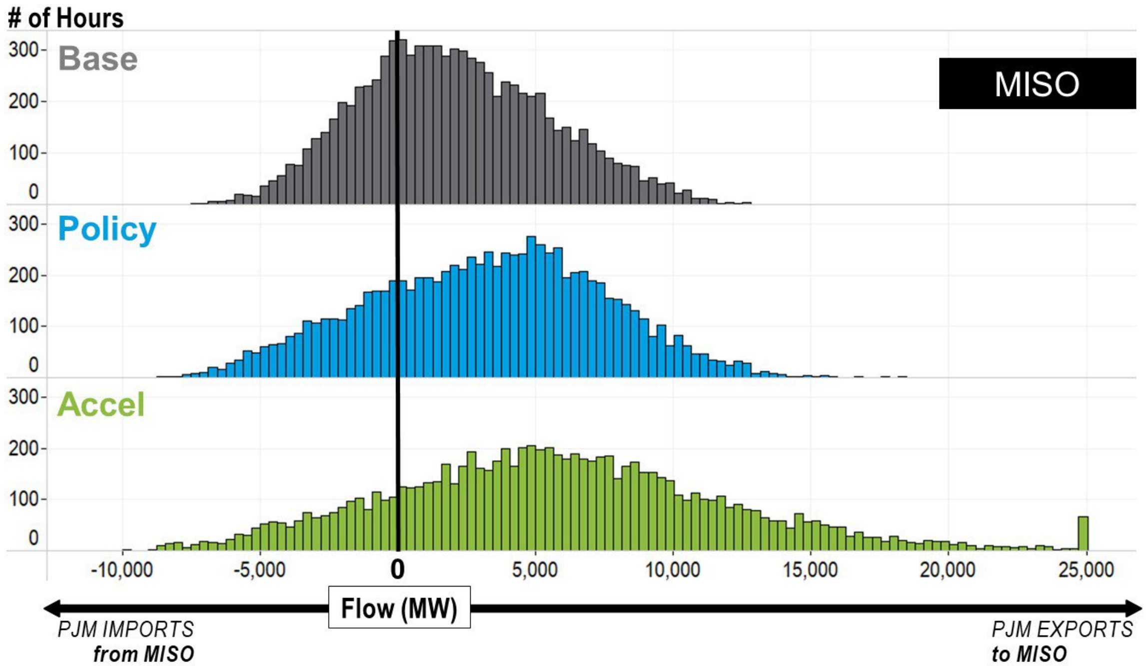


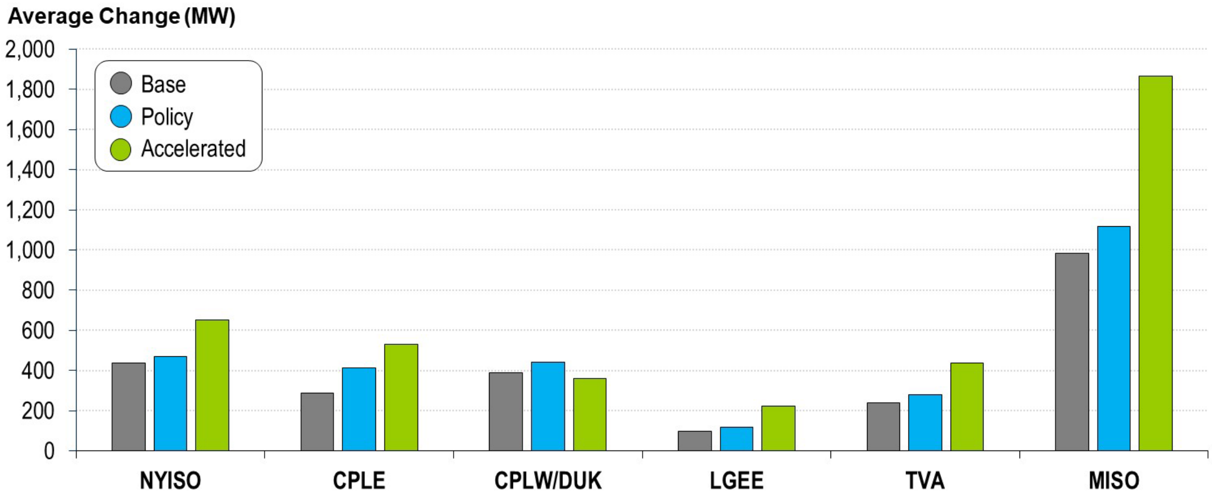
Table 3. Percentage of Hours Interfaces Bound at the Associated Transfer Limit

		Count of Hours at Limit											
		+/- 3,000 MW		+/- 2,000 MW		+/- 2,890 MW		+/- 3,000 MW		+/- 24,850 MW		+/- 4,200 MW	
		East to NYISO		South to CPLE		West to CPLW/DUK		West to LGEE		West to MISO		West to TVA	
		Export	Import	Export	Import	Export	Import	Export	Import	Export	Import	Export	Import
Base	Hours	132	58	4	2,777	38	0	0	0	0	0	0	0
Policy	Hours	1,063	47	1,196	301	81	0	0	0	0	0	0	0
Accel	Hours	1,021	470	2,253	722	890	0	0	0	65	0	0	0
Base	%	1.51%	0.66%	0.05%	31.72%	0.29%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Policy	%	12.13%	0.54%	13.65%	3.44%	0.92%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Accel	%	11.66%	5.37%	25.72%	8.24%	10.16%	0.00%	0.00%	0.00%	0.74%	0.00%	0.00%	0.00%

Increased renewable penetration also resulted in an intensification in hourly average RTO interchange by a factor of nearly 10 between Base (753 MW export) and Accelerated cases (7,331 MW export). The hourly maximum interchange also doubled in the Accelerated case (36,677 MW export) compared to the Base case (17,798 MW export). These trends hold true across all seasons, with winter being the season with peak exporting needs among PJM and neighboring regions.

In addition to increases in overall interchange needs, the associated intermittent nature of renewables and their increased role in each region's fleet resulted in higher levels of volatility in hour-to-hour interchange ramp, shown by interface in **Figure 9**. This is highlighted in the Accelerated case between PJM and MISO where, on average, interchange between the two regions changes by over 1,800 MW every hour. Between PJM and MISO, 21% of hours in the Accelerated scenario saw an intra-hour interchange swing greater than 3,000 MW, compared to about 4% of the hours in the Base and Policy scenarios.

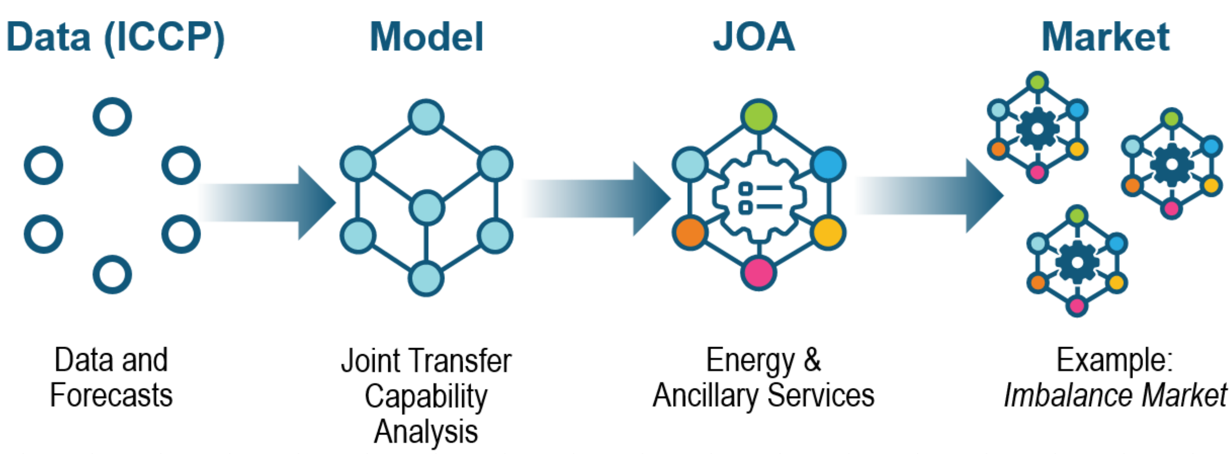
Figure 9. Interchange Ramping Needs per Interface



The increasing volatility in interchange, driven by intermittent resource variability, will require enhanced coordination with neighbors. Summarized in terms of complexity in **Figure 10**, "enhanced coordination" may include:

- Updating interregional planning to better capture intermittent resource behavior and review methods for defining tie limits. For example, updating based on physical limits of the lines and accounting for interregional transmission expansion that could increase transfer capability.
- Updating JOAs and creating them with neighbors where they do not currently exist. This may include more data sharing for inputs such as wind forecasts.
- Working with neighbors on how to better operate with and account for large interchange swings and volatility. Investigate enhanced optimization approaches to support this.

Figure 10. Areas for Enhanced Interregional Coordination

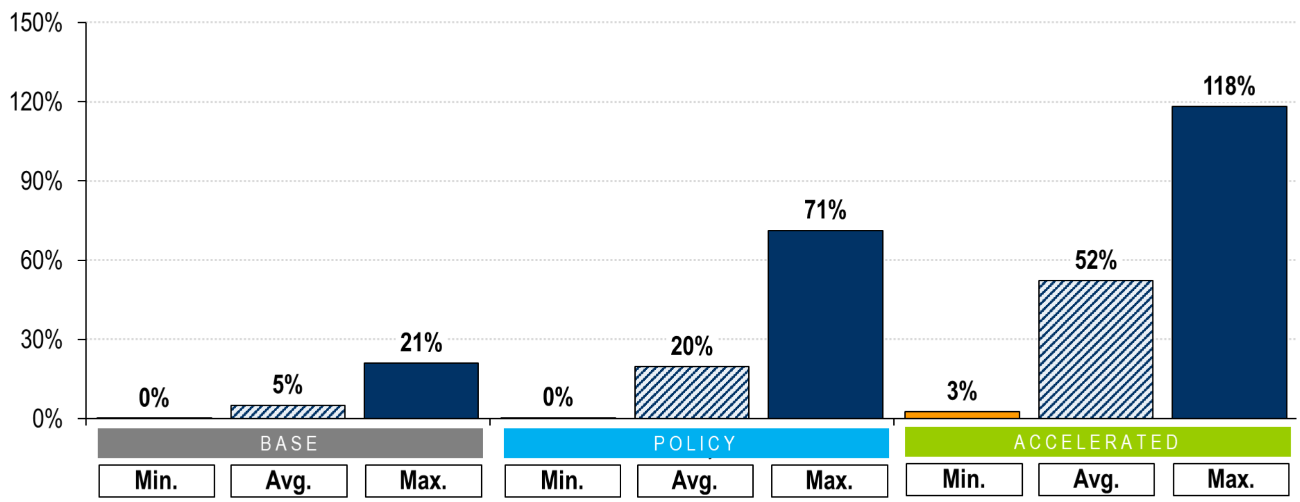


Multiday, Dispatchable Resources Are Needed

Increasing levels of intermittent resources create significant variability and uncertainty to be managed by flexible resources. Intermittent renewable generation instantaneously represented as much as 118% of the RTO load (with exports) in the Accelerated case, as shown in **Figure 11**. Renewables also accounted for as little as 3% of the RTO load.

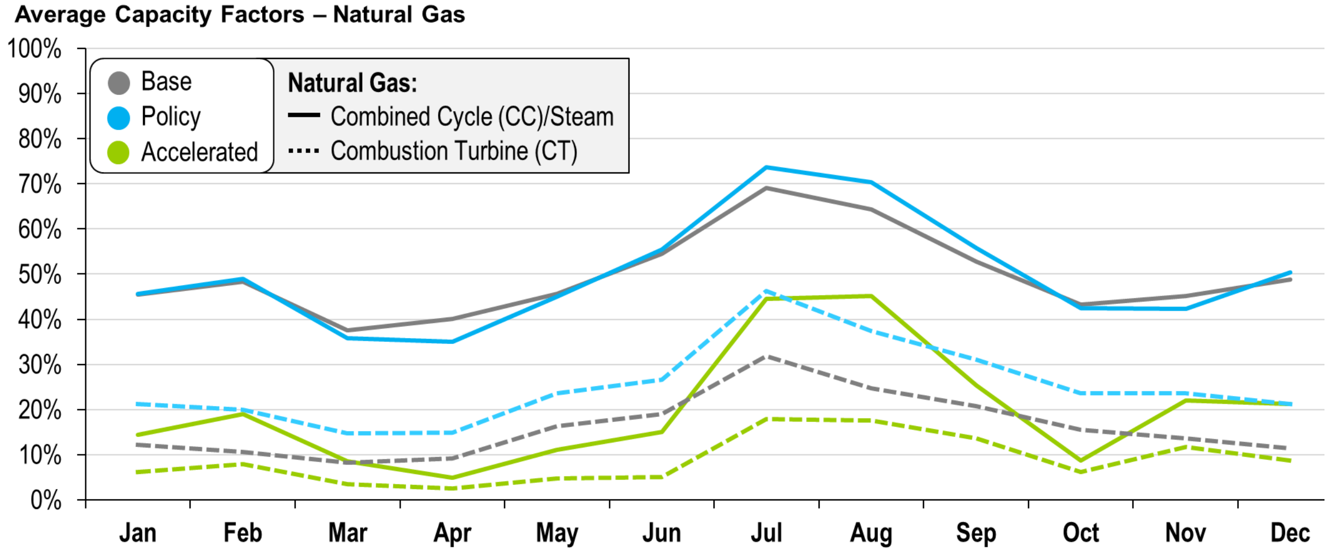
The scenarios also saw increasing extremes in the net load (demand minus intermittent generation) and changes in it. For example, in the Base scenario, the max net load change was three times the average, while in the Accelerated this max was six times the average. Net load ramp over a three-hour period maxed out at 105 GW in the Accelerated scenario, which is greater than the peak load of the entire ERCOT system. These trends highlights a new scale of uncertainty to be managed to balance the system and meet ramping needs.

Figure 11. Intermittent Output as Percent of Load



From the Base to Policy scenario, natural gas resource capacity factors increase to manage thermal retirements. Moving into the Accelerated scenario, natural gas utilization decreases as the combined cycles operate as flexible peakers rather than baseload. Adding to the complexity, the need for flexible resources, in particular to meet ramping needs, varies drastically by season. In **Figure 12,** the average capacity factors for natural gas combined-cycle generators ranged from 35% in April in the Policy scenario to only 5% in the Accelerated scenario – an 86% decrease. However, average capacity factors for July decreased by 39% – from 74% in the Policy scenario to 45% in the Accelerated scenario. These patterns show combined cycles operating as flexible peakers rather than baseload. Combustion turbines showed similar decreases, with a larger decrease in the summer months between the Policy and Accelerated cases.

Figure 12. Natural Gas – Average Capacity Factors by Month



Lower demand periods in the fall and spring, paired with large additions of zero-cost or low-cost resources in the Accelerated case, contributed to persistent low energy prices through these periods. During these times, thermal resources experience idle stretches. In an extreme circumstance, the natural gas fleet did not provide any output for 43 consecutive hours in the Accelerated scenario, between June 1 at 10 p.m. and June 3 at 4 p.m. As a result, natural gas combined-cycle revenues decreased 54% annually between the Base and Accelerated cases and 55% from the Base to the Policy cases. Seasonally, the differences in average revenue ranged from a 39% drop in the winter and 91% in the spring in the Accelerated case. Average LMP received by natural gas resources are shown alongside their monthly capacity factors in **Table 4**.

Table 4. Average LMP Received by Resource ($/MWh) vs. Capacity Factor (%)

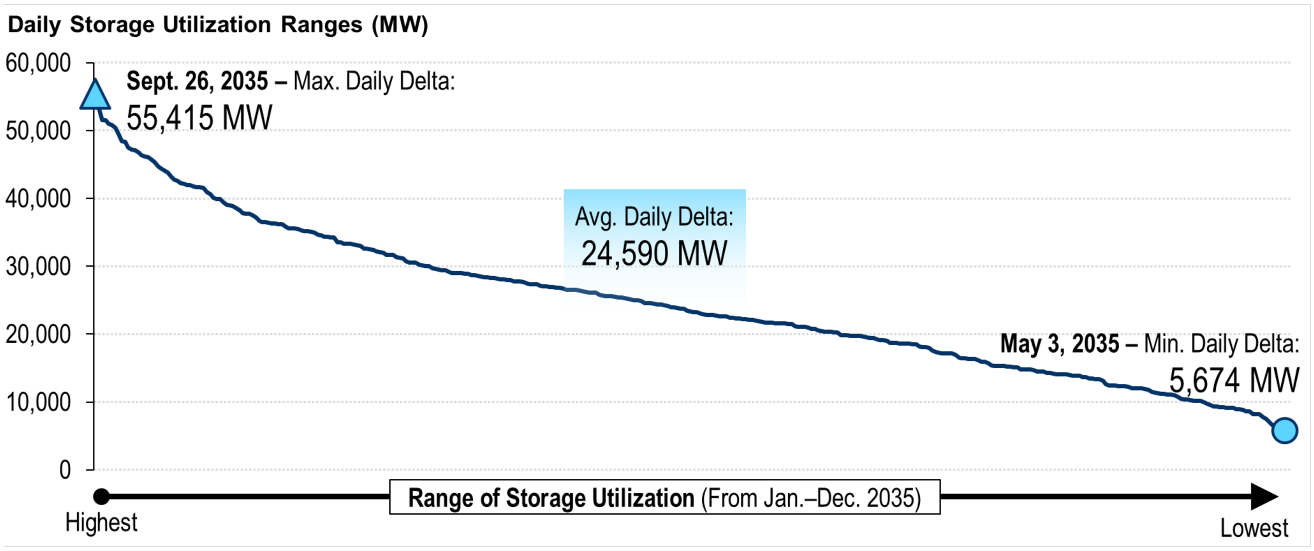
	Natural Gas CC / Steam						Natural Gas CT					
	Base		Policy		Accel		Base		Policy		Accel	
	$/MWh	%	$/MWh	%	$/MWh	%	$/MWh	%	$/MWh	%	$/MWh	%
Jan.	$46	45%	$49	46%	$22	14%	$51	12%	$58	21%	$32	6%
Feb.	$44	48%	$46	49%	$27	19%	$49	11%	$56	20%	$36	8%
Mar.	$37	38%	$37	36%	$14	8%	$42	8%	$47	15%	$19	4%
Apr.	$33	40%	$33	35%	$8	5%	$38	9%	$42	15%	$12	3%
May	$35	46%	$37	45%	$15	11%	$42	16%	$48	24%	$19	5%
Jun.	$37	54%	$40	55%	$16	15%	$44	19%	$50	27%	$19	5%
Jul.	$52	69%	$79	74%	$40	45%	$60	32%	$99	46%	$41	18%
Aug.	$43	64%	$50	70%	$38	45%	$49	25%	$59	37%	$40	18%
Sept.	$38	53%	$41	56%	$24	25%	$44	21%	$52	31%	$28	14%
Oct.	$34	43%	$35	42%	$12	9%	$39	16%	$44	24%	$15	6%
Nov.	$40	45%	$42	42%	$26	22%	$45	14%	$52	24%	$33	12%
Dec.	$43	49%	$46	50%	$27	21%	$48	11%	$55	21%	$36	9%

Even with increasing polarization in seasonal utilization, flexible resources like natural gas and storage, are needed to manage system balancing and ramping needs. In the Accelerated scenario, total system ramping needs were met by energy storage (43%), thermal resources (32%), interchange (15%) and hydro (7%).

The total gas burned by PJM generation across the full year showed an 11% decrease from the Base scenario to the Policy scenario and a 66% decrease from the Base scenario to the Accelerated scenario. Peak usage is in the summer months across all scenarios, followed by winter, fall and spring, respectively. Additional flexibility in nomination cycles and ratable take requirements will be needed to support natural gas resources to balance the system during times of low intermittent-resource output and during times of high net load ramps. Resources may not receive the advance notice they need to procure adequate gas supply under today's market constructs (both gas and electric). Enhanced forecasting of these types of events may help inform gas supply needs for generators.

A large amount of storage is assumed to be built in this study, with up to 27 GW of stand-alone batteries and 53 GW of solar-storage hybrids in the Accelerated scenario. This storage capability is utilized heavily. **Figure 13** shows the difference between the largest discharge interval and the largest charge interval for each day. The smallest difference, or the day in which the swing between charging and discharging was smallest, was 5.6 GW, which still shows a significant variability throughout the day. In an Accelerated scenario-like future, energy storage will need to be optimized to handle these dramatic ramps in load and renewables while maintaining a reliable state of charge. There will be a need to enhance how storage is optimized in markets and operations today to best utilize large amounts of storage on the system.

Figure 13. Energy Storage Utilization in Accelerated Scenario



If the gas fleet of today remains as is, or decreases due to regulatory pressures, but additional storage resources do not get built, immense pressure will be placed on natural gas to supply the ramping needs for the system. Changes to market mechanisms must be evaluated to ensure that thermal resources are incentivized to meet evolving system needs.

Moving Forward

PJM must evolve to address the complexity of the energy transition as increasing levels of intermittent resources create significant variability and uncertainty.

Continuing to track mismatches among:

- Resource retirements
- Load growth
- Pace of new generation entry
- Transmission buildout

Enhancing interregional coordination to better manage existing interregional capability that will be needed with the increasing volatility and uncertainty that is anticipated

Continually evaluating evolving system needs for essential reliability services, and developing market mechanisms to require and incentivize them