The Next Decade in PJM

A Path to Reliability and Affordability

Prepared for Advanced Energy United

February 2026

AUTHORS

Caroline Resor
Sabine Chavin
Patrick Knight
Selma Sharaf

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 3
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

CONTENTS

EXECUTIVE SUMMARY I

1. INTRODUCTION 1
   - 1.1. PJM's Demand Growth and Supply Constraint Challenges 1
   - 1.2. Overview of Grid Reliability 4
   - 1.3. Advanced Energy Technologies as a Solution to Reliability and Affordability Concerns 7

2. METHODS 9
   - 2.1. Capacity Expansion Modeling Methods 9
   - 2.2. Capacity Expansion Resource Build Outputs 13
   - 2.3. Resource Adequacy Modeling Methods 16

3. RELIABILITY RESULTS 18
   - 3.1. Increased Deployment of AETs Avoids Power Outages in the Near and Long Term 18
   - 3.2. AETs Mitigate Risk During Both Winter and Summer Periods 23
   - 3.3. AETs Help Provide Reliable Electricity During Extreme Weather Events 26

4. COSTS AND EMISSIONS RESULTS 30
   - 4.1. Increased Deployment of AETs Reduces Costs Relative to the Status Quo Scenario 30
   - 4.2. Deploying More AETs Also Lowers CO_2 Emissions 31

5. DISCUSSION AND CONCLUSION 32
   - 5.1. Enabling Policies to Accelerate Deployment of AETs 32
   - 5.2. Risks of Overreliance on Traditional Fossil Resources 34

EXECUTIVE SUMMARY

Grid reliability is a growing concern in PJM. In a December 2024 letter, the PJM Board warned that PJM may face the threat of insufficient capacity to meet load as soon as June 2026. PJM members and the Board continued to focus on this concern throughout 2025, and it is expected to remain a primary focus for the region in 2026. In the most recent PJM capacity auction, which was conducted for the 2027/2028 delivery year, PJM was unable to procure enough capacity to meet its reliability standard of one-event-in-10-year.[1]

Load growth increases the risk of resource inadequacy. PJM's 2025 load forecast projects that summer peak load will increase by 32 GW from 2024 to 2030, with data centers driving 94 percent of this near-term growth.[2] At the same time, interconnection delays, supply chain constraints, and siting and permitting challenges currently restrict the amount of new supply that can be quickly added to the grid. The combination of growing loads and barriers to new supply could decrease grid reliability and increase outages.

This study examines how advanced energy technologies (AETs) can help address the reliability challenges that threaten PJM. We modeled two scenarios: a business-as-usual Status Quo scenario that assumes limited AET deployment through 2035, based on historical resource deployment trajectories and consistent with current policy constraints, and an Advanced Policy scenario that allows for increased, but still realistic levels of AET deployment.

We find that allowing for the increased deployment of advanced energy technologies in PJM reduces the expected frequency of outages in 2030 by 97 percent and reduces the number of customers affected by outages by 87 percent. Our findings demonstrate that AETs can play a key role in reducing PJM's reliability challenges in both 2030 and 2035. We also find that this increased reliability comes at a lower cost; over 2025–2035, **adding advanced energy technologies offers cumulative cost savings of $178 billion, or 20 percent,** relative to the Status Quo scenario.

---

[1] PJM. December 17, 2025. "2027/2028 Base Residual Auction Report". Available at: https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2027-2028/2027-2028-bra-report.pdf

[2] We use PJM's 2025 load forecast in this analysis so that we can respond to the concerns that PJM has identified. This study does not evaluate the accuracy of the load forecast. This study was conducted prior to the release of PJM's 2026 load forecast (released in January 2026). We note that PJM-wide, this 2026 new load forecast has a 2030 summer peak that is 0.5 percent lower than the 2025 load forecast, and a 2035 summer peak that is 3.3 percent higher than the 2025 load forecast.

For the purposes of this analysis, advanced energy technologies (AETs) include:

- **Supply-side resources** such as large-scale wind, solar, and storage
- **Demand-side resources** such as distributed solar, energy efficiency, and demand response
- **Advanced transmission technologies** such as reconductoring and dynamic line rating (DLR) improvements

Many advanced energy technologies are ready to deploy, have the potential to come online more quickly than new gas resources, and could help address projected supply–demand imbalances. However, status quo policies and regulatory barriers hinder the expansion of these resources in PJM.

Synapse conducted power sector capacity expansion and resource adequacy modeling to evaluate how AETs could contribute to resource adequacy in PJM over the next decade. Knowing that no energy resource is perfectly reliable—including traditional resources such as gas-fired power plants—this study takes a system-wide view to investigate how adding more AETs might enable *all* energy resources (including non-AET resources) to complement one another better and improve reliability for PJM. It is important to note that this study focuses on reliability of the bulk power system, not the distribution system. We find:

- **Overall, the Status Quo scenario with limited AET deployment confirms PJM's reliability concerns.** PJM's Loss of Load Expectation (LOLE) standard calls for outages to occur no more often than 0.1 days per year, or one day in 10 years.[3] However, in the Status Quo scenario in 2030, PJM is expected to experience reliability issues 1.6 days per year (see Table 1), 16 times the maximum under the PJM standard. When outages occur, customers lose power or are partially curtailed.

*In the Status Quo scenario, outages occur 1.6 days per year in 2030—16 times more often than the PJM standard of 0.1 days per year. In the Advanced Policy scenario, outages occur only 0.04 days per year, or 1 day per 25 years. Outages are **97 less frequent** in the Advanced Policy scenario than in the Status Quo scenario.*

- **Increased deployment of AETs avoids power outages in 2030**. The Advanced Policy scenario shows only very rare power outages in 2030, only 0.04 days expected per year, or one day in 25 years (see Figure 1). This is 97 percent better than in the Status Quo scenario. Adding more AETs to the PJM system greatly increases resource diversity, which improves the reliability of the bulk power system.

---

[3] LOLE is measured in days per year or fractions of a day (rather than hours or minutes) because it is a measure of frequency, not duration. In other words, a LOLE of 0.1 does not mean an outage of one-tenth of a day per year, but one day with outages every 10 years.

- **AETs improve other metrics beyond outage frequency in 2030.** In the Status Quo scenario, outages are expected to last 88 minutes per event, whereas in the scenario with AETs, the expected duration is just 7 minutes per event. AETs also decrease the extent of an outage: Adding AETs decreases the maximum unserved load by 87 percent. If these outages exclusively affected residential customers, 87 percent fewer customers would lose power in the Advanced Policy scenario than in the Status Quo scenario.

> *In addition to being less frequent, outages in the Advanced Policy scenario are also* ***92 percent shorter*** *and* ***87 percent smaller*** *than outages in the Status Quo scenario.*

- **AETs' contribution to reliability increases through 2035**. As the deployment of AETs increases over time, the reliability of the bulk power system improves. In the Advanced Policy scenario, LOLE drops by 64 percent between 2030 and 2035, from one day in 25 years to one day in 70 years—seven times better than the PJM standard of 0.1 days per year. In contrast, in the Status Quo scenario, despite the addition of some new resources, LOLE in 2035 is 0.4 days per year, four times worse than the PJM standard.

- **AETs improve reliability in the winter, when the risk of outages is greatest.** Consistent with PJM's own modeling, our analysis illustrates that winter has become the dominant season for reliability issues. One reason for this is that natural gas- and coal-fired power plants have higher rates of forced outages during cold weather periods; deploying AETs helps to compensate for this. AETs reduce the impact of these forced outages through increased energy storage, demand response, wind power and energy efficiency. This decreases the size of winter reliability events by 89 percent in 2030 and by 99 percent in 2035 relative to the Status Quo scenario.

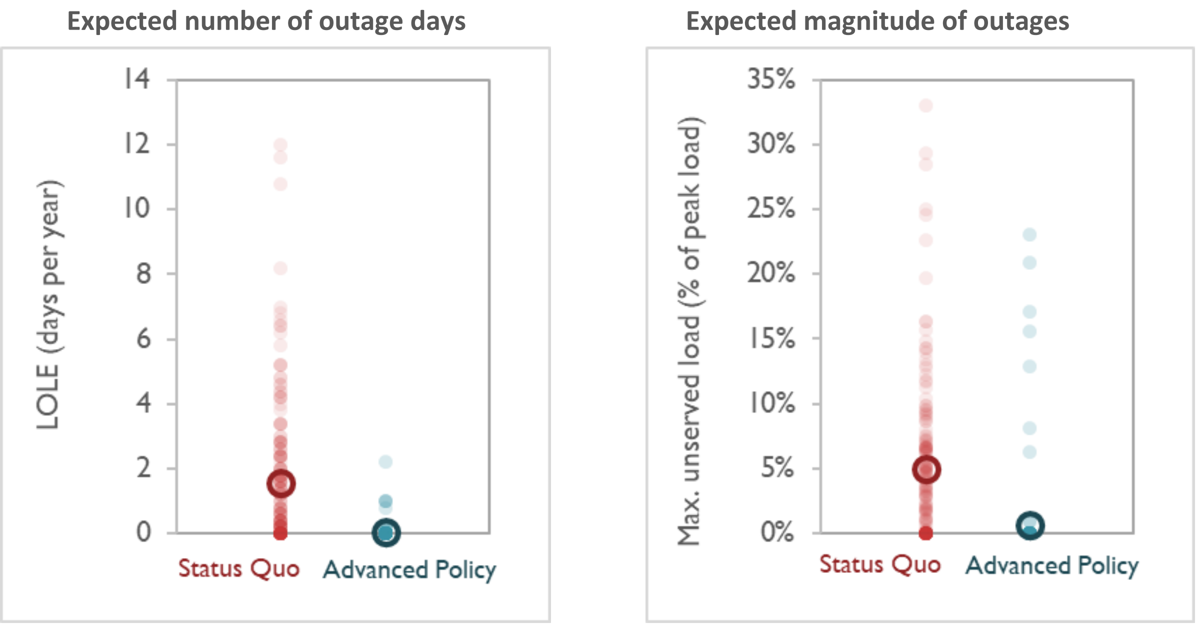
- **AETs also improve reliability during extreme heat events.** We modeled a summer weekend in 2030 with temperatures exceeding 100°F and found that in the Status Quo scenario, customers would lose power. In the Advanced Policy scenario, additional solar generation, storage, and demand response enable PJM to avoid an outage.

- **AETs reduce both costs and emissions relative to the status quo**. Along with providing much more reliable bulk power, the Advanced Policy scenario is less expensive than the Status Quo scenario in every year. Over 2025–2035, we observe that adding AETs offers cumulative cost savings of $178 billion, or 20 percent, relative to the Status Quo scenario. At the same time, AETs decrease annual carbon dioxide emissions from the electric sector every year, up to 33 percent in 2035.

Table 1. Summary of expected PJM reliability performance by scenario in 2030 and 2035

Year	Scenario	Outage frequency *Loss of Load Expectation (LOLE), number of days per year with events*	Outage duration *Expected duration per event*	Outage maximum magnitude *Max. hourly unserved load, highest amount of unserved load per year*
2030	**Status Quo**	**1.6 days per year**	88 minutes	9.3 GW (5 percent of PJM peak load)
	Advanced Policy	**1 day per 25 years**	7 minutes	1.2 GW (0.6 percent of PJM peak load)
2035	**Status Quo**	**1 day per 2 years**	55 minutes	7.4 GW (3 percent of PJM peak load)
	Advanced Policy	**1 day per 70 years**	2 minutes	0.9 GW (0.4 percent of PJM peak load)

Figure 1. Reliability performance of the Status Quo and Advanced Policy scenarios in PJM in 2030



Note: Each dot represents a simulated year-load forecast pair. Circles are expected values (probability-weighted averages).

1. INTRODUCTION

Grid reliability is becoming a pressing concern in PJM. In a December 2024 letter, the PJM Board warned that PJM may face the threat of insufficient capacity to meet load as soon as June 2026.[4] PJM members and the Board continued to discuss their concerns about resource adequacy throughout 2025 and into 2026.[5] Ensuring reliability in PJM will require managing the region's high demand growth and addressing supply constraints.

1.1. PJM's Demand Growth and Supply Constraint Challenges

High, but uncertain, load growth

PJM is predicting high load growth, both in terms of peak demand and annual load.[6] Figure 2 shows PJM's 2025 load forecast, which projects that summer peak load will increase by 32 GW, or 21 percent, between 2024 and 2030.[7] PJM expects data center growth to drive 30 GW (94 percent) of the total.[8]

Load forecasts are inherently uncertain, and subsequent PJM load forecasts may change significantly due to future data center industry developments or changes to forecasting methodology. Nonetheless, this study assesses how advanced energy technologies (AETs) could contribute to the reliability of the PJM grid in 2030 and 2035.[9] Although the precise quantity of capacity additions needed may change as PJM load forecasts evolve in the future, insights from this study about the ability of AETs to address high load growth will remain relevant.

---

[4] PJM. December 9, 2024. "Letter from the PJM Board of Managers." Available at: https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2024/20241209-board-letter-outlining-action-on-capacity-market-adjustments-rri-and-sis.pdf

[5] PJM. August 2025. "PJM Board Fast-Tracks Effort to Reliably Serve Large Loads." Available at: https://insidelines.pjm.com/pjm-board-fast-tracks-effort-to-reliably-serve-large-loads/

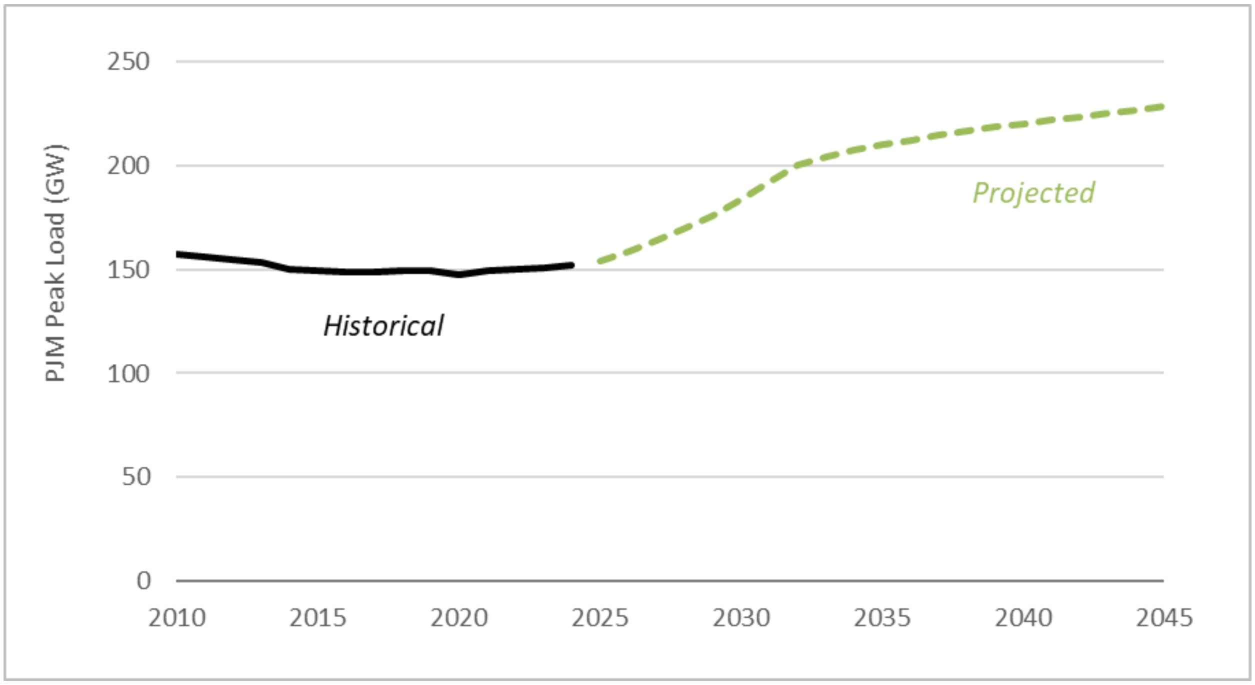
[6] The winter peak is expected to grow but still be slightly lower than the summer peak through 2039. PJM estimates that annual demand will increase by 495,264 GWh, or 59 percent, between 2025 and 2035.

[7] PJM Resource Adequacy Planning Department. January 24, 2025. "PJM 2025 Long-Term Load Forecast Report." Page 6 and Tab F1. Available at: https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2025-load-report.pdf

[8] PJM. August 8, 2025. "Letter from the PJM Board of Managers." Available at: https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2025/20250808-pjm-board-letter-re-implementation-of-critical-issue-fast-path-process-for-large-load-additions.pdf

[9] This study does not evaluate the accuracy of PJM's load forecast.

Figure 2. PJM historical peak load and 2025 load forecast



Note that this study was conducted prior to the release of PJM's 2026 load forecast (released in January 2026). PJM-wide, this new 2026 load forecast has a 2030 summer peak that is 0.5 percent lower than the 2025 load forecast, and a 2035 summer peak that is 3.3 percent higher than the 2025 load forecast.[10]

Interconnection delays and ongoing need for reform

On the supply side, the PJM region has struggled with project interconnection delays for large-scale generation projects, global supply chain challenges, and local siting and permitting slowdowns and roadblocks. At the end of 2023, PJM had a larger backlog of projects seeking to interconnect than any other grid operator in the United States.[11]

PJM has been reforming its interconnection process, streamlining the addition of all resource types to reduce interconnection timelines. PJM's transition to studying projects in clusters, rather than serially, was approved by the Federal Energy Regulatory Commission (FERC) in 2022, and is expected to result in a faster interconnection process. However, the new process is still untested; the deadline for projects to

---

[10] For more on the 2026 load forecast and differences between it and the 2025 load forecast, see https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process.

11 Rand, J., N. Manderlink, W. Gorman, R. Wiser, J. Seel, J. Mulvaney Kemp, S. Jeong, F. Kahrl. Lawrence Berkeley National Laboratory. April 2024. Queued Up: 2024 Edition, Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2023. Available at: https://emp.lbl.gov/publications/queued-2024-edition-characteristics

apply for interconnection agreements under PJM's first cluster study is in April 2026.[12] PJM has pursued some additional reforms, such as improving its Surplus Interconnection Service and enabling easier transfer of capacity rights between existing and new resources.[13] While PJM has made some progress in clearing out its interconnection backlog, FERC determined in July 2025 that PJM's reforms to date fall short of what is needed to comply with Order 2023, a ruling meant to streamline and standardize interconnection processes across the country. FERC called on PJM to make additional changes to improve study timelines, upgrade cost allocation, and evaluate the potential for certain advanced technologies to ease interconnection challenges.[14]

Recent PJM initiatives and proposals to address projected reliability concerns have resulted in adding primarily traditional, large generators, such as large gas plants. PJM's Reliability Resource Initiative (RRI), a one-time opportunity that has fast-tracked 51 projects, used a scorecard that heavily weighed a given resource's firm capacity and effective load carrying capability (ELCC). This effectively prioritized large natural gas plants and resulted in PJM selecting gas for 8 GW of the total 12 GW expected to come online through RRI.[15] More recently, PJM's Expedited Interconnection Track (EIT) proposal to address reliability concerns related to large loads would only be open to large-scale generators greater than 250 MW.[16]

Supply chain and regulatory constraints

Supply chain constraints are driving up the cost of new gas turbines and increasing lead times for turbines and associated equipment. As of fall 2025, the current wait time for a gas turbine is five to seven years, meaning a new turbine ordered in 2025 may not be available until 2030–2032.[17]

The authority for siting and permitting energy projects varies by state, and the process can include steps under local jurisdiction, with the state, and with the federal government. With the acceleration of renewable energy development in recent years, these processes are struggling to keep up. PJM announced in June 2025 that 46 GW of projects—enough to power 40 million homes—have signed interconnection agreements but have not been built yet, due to supply chain, siting, and permitting

---

[12] PJM. "PJM Completes Interconnection Reform Transition Cycle 1 Studies." September 22, 2025. Available at: https://insidelines.pjm.com/pjm-completes-interconnection-reform-transition-cycle-1-studies/

[13] Surplus interconnection service improvements will allow additional resources such as solar or storage to plug in alongside facilities that do not operate continuously to provider service during the unused time.

[14] Order on Compliance, E-2-ER24-2045-000 FERC. July 24, 2025. Available at: https://www.ferc.gov/media/e-2-er24-2045-000

[15] PJM. May 2025. "PJM Chooses 51 Generation Resource Projects to Address Near-Term Electricity Demand Growth". Available at: https://insidelines.pjm.com/pjm-chooses-51-generation-resource-projects-to-address-near-term-electricity-demand-growth/

[16] PJM. October 1, 2025. "Large Load Additions CIFP Update". Available at: https://www.pjm.com/-/media/DotCom/committees-groups/cifp-lla/2025/20251001/20251001-item-04---cifp---lla-updates---pjm-presentation.pdf

[17] Anderson, Jared. May 20, 2025. "US gas-fired turbine wait times as much as seven years; costs up sharply." *S&P Global*. Available at: https://www.spglobal.com/commodity-insights/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply

issues.[18] Within PJM, several states—Ohio, Virginia, Kentucky, and North Carolina—require projects be reviewed by state and local authorities.[19] Complex siting processes, restrictive local ordinances, and limited resources to review projects at the local level can slow down the timeline to construction—or stop projects from getting online at all.[20]

These constraints, coupled with unprecedented demand projections, raise serious concerns about PJM's ability to have sufficient capacity to maintain reliability if PJM's high load forecasts are borne out.

How Supply and Demand Shape Energy Affordability

Having adequate supply to meet demand is a reliability objective, *and* it is critical for keeping costs and customer electric bills down. The high load forecast and supply slowdown have already raised prices in the region's capacity market, with direct impacts on electricity bills in the PJM region. In July 2024, capacity prices for the 2025–2026 delivery year hit record highs of $269.92 per MW-day, nearly 10 times the previous year's clearing price. In response to the high capacity prices, a price cap was implemented ahead of the auctions for the 2026–2027 and 2027–2028 delivery years. In July 2025, the price cap kept capacity prices from exceeding $329.17 per MW-day—but still represented a 22 percent increase over the previous record high.[21] The recent capacity auctions have led to double-digit bill increases for some customers in the PJM region.[22]

1.2. Overview of Grid Reliability

Maintaining grid reliability is one of the most important jobs of grid planners and operators. Reliability has three components, defined in Table 2 below: Resource adequacy, operational reliability, and resilience.[23] This study focuses on resource adequacy—that is, having sufficient power resources to

---

[18] PJM. June 2025. "Generation Interconnection Factsheet." Available at: https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/interconnection-reform-progress-fact-sheet.pdf

[19] Breckel, A., N Falkenburg. April 2025. *State Policy Approaches to Renewable Energy Siting.* Clean Tomorrow. Available at: https://cleantomorrow.org/wp-content/uploads/2025/05/cleantomorrow_siting-solutions-project_insight-report.pdf

[20] Adcox, G., K. Hanley. September 2025. *From Barriers to Breakthroughs: State Policymaker Perspectives on Renewable Energy Siting*. Clean Tomorrow and Data for Progress. Available at: https://www.filesforprogress.org/memos/From_Barriers_to_Breakthroughs_State_Policymaker_Perspectives_on_Renewable_Energy_Siting_Report.pdf

[21] Howland, Ethan. July 23, 2025. "PJM capacity prices set another record with 22% jump." *Utility Dive*. Available at: https://www.utilitydive.com/news/pjm-interconnection-capacity-auction-prices/753798/

[22] Howland, Ethan. October 2, 2025. "Data centers 'primary reason' for high PJM capacity prices: market monitor." *Utility Dive*. Available at: https://www.utilitydive.com/news/data-centers-pjm-capacity-auction-market-monitor/801780/

[23] National Renewable Energy Laboratory. 2024. Explained: Fundamentals of Power Grid Reliability and Clean Electricity. Available at: https://docs.nrel.gov/docs/fy24osti/85880.pdf

meet future load while accounting for load and generation uncertainty.[24] If supply is insufficient to meet demand, an outage, or “loss of load,” can occur.

---

[24] Energy Systems Integration Group. 2021. Redefining Resource Adequacy for Modern Power Systems. Available at: https://www.esig.energy/wp-content/uploads/2022/12/ESIG-Redefining-Resource-Adequacy-2021-b.pdf

Table 2. Definitions of grid reliability

Reliability component	Definition
Resource adequacy	The ability to supply the electrical demand and energy requirements of customers, considering scheduled and reasonably expected unscheduled outages of system elements.
Operational reliability	The ability to withstand sudden disturbances and avoid uncontrolled blackouts or damage to equipment.
Resilience	The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event.

Planners model the reliability of a system by stress testing the system's resources and load, or supply and demand, under a vast array of weather conditions. Systems will also have a target reliability level, which represents the acceptable level of risk. Planners have traditionally set this reliability target (loss of load expectation, or LOLE) at a standard of one day of lost load in 10 years.[25] For robust planning, it is helpful to assess other dimensions of reliability besides power outage frequency. Table 3 describes several metrics used for measuring reliability, including for outage frequency, duration, and magnitude. It may also be useful to consider the seasonal distribution of these different risk metrics, as well as both the expected value and the maximum values of each.

---

[25] National Renewable Energy Laboratory. 2024. Explained: Fundamentals of Power Grid Reliability and Clean Electricity. Available at: https://docs.nrel.gov/docs/fy24osti/85880.pdf

Table 3. Reliability metrics and examples of standards

Topic	Metric	Illustrative example of standard
Event frequency	**Loss of Load Expectation (LOLE)** describes the number of **days per year** with events.	The PJM standard is 1 day in 10 years or 0.1 days per year.[26]
	Loss of Load Hours (LOLH) describes the **number of hours per year** with events.	There is no defined standard in PJM. ERCOT, for example, uses a standard of 12 hours once per 100 years for this metric.[27]
Event duration	**Expected duration** describes the **average number of hours** per event.	There is no defined standard in PJM.
Event magnitude	**Expected Unserved Energy (EUE)** describes the **total quantity of unserved energy** per year, in GWh.	There is no defined standard in PJM. Alberta, Canada, for example, uses a standard of 0.8 GWh per year for this metric.[28]
	Maximum Hourly EUE describes the **highest amount of unserved load** per year, in GW.	There is no defined standard in PJM. ERCOT, for example, uses a standard of 19 GW once per 100 years or 0.19 GW per year.[29]

1.3. Advanced Energy Technologies as a Solution to Reliability and Affordability Concerns

This study examines the extent to which AETs could help address PJM's potential reliability concerns. For the purposes of this analysis, advanced energy technologies (AETs) include supply-side resources such as large-scale wind, solar, and storage; demand-side resources such as distributed solar, energy efficiency, and demand response; and advanced transmission technologies such as dynamic line ratings and

---

[26] PJM Resource Adequacy Planning. May 21, 2025. PJM Manual 20A: Resource Adequacy Analysis. Page 8. Available at: https://www.pjm.com/-/media/DotCom/documents/manuals/m20a.ashx

[27] Ming, Z., D. Delgado. "The Role of Metrics in Determining a Reliability Standard." Presentation at MISO RA Risk Metrics Workshop. September 26, 2024. Available at: https://cdn.misoenergy.org/20240926%20RA%20Risk%20Metric%20Workshop%20Item%2004%20Ming%20E3%20MISO%20Role%20of%20Metrics%20in%20Reliability650106.pdf

[28] Ibid.

[29] Ibid.

reconductoring. Many of these resources are ready to deploy more quickly than new gas resources and could help address projected imbalances between supply and demand.

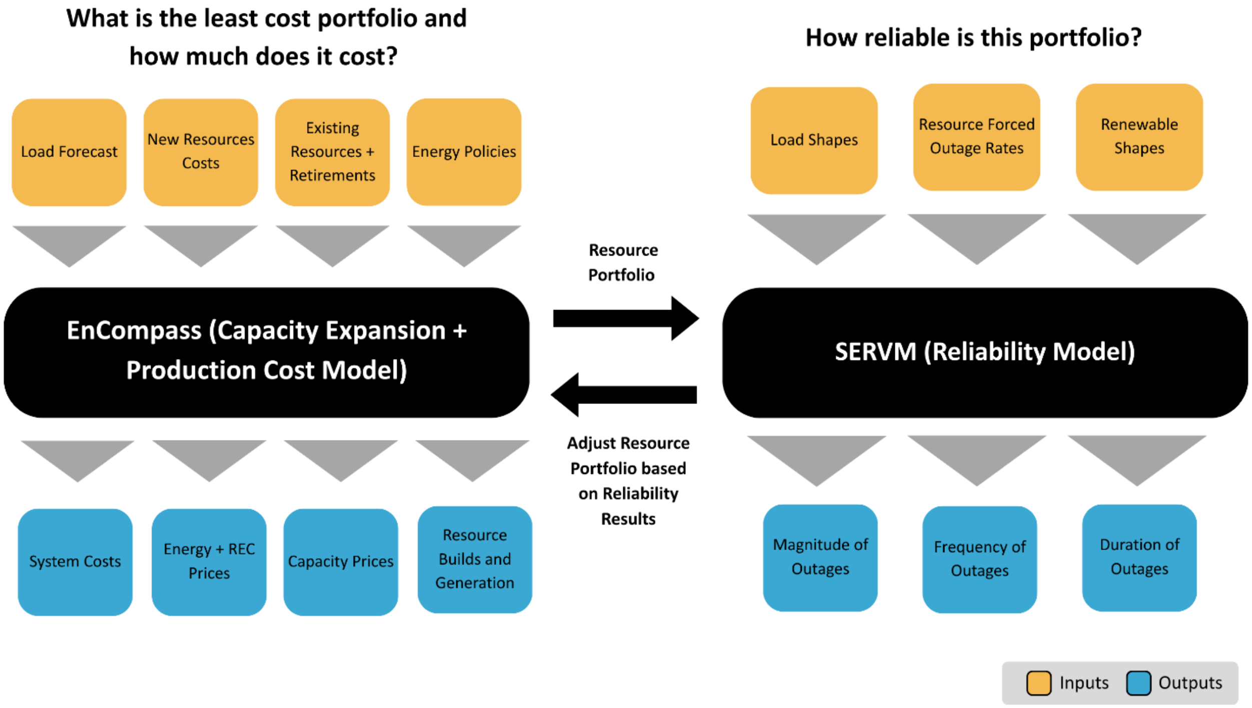
Adding more AETs to the grid also improves resilience during extreme weather events, since different resources have different outage profiles. Residents, elected officials, and electricity experts alike remember the close call that was Winter Storm Elliott in December 2022. Plunging temperatures, ensuing high load, and high rates of natural gas and coal plant outages tested grid operators, who very narrowly avoided rolling blackouts by calling for energy conservation and activating emergency demand response and other procedures. In this instance, PJM’s grid could potentially have been more resilient had it been less reliant on gas and coal resources.

For this study, Synapse conducted power sector capacity expansion and resource adequacy modeling to evaluate how AETs can contribute to resource adequacy in PJM over the next decade. This study takes a system-wide view to investigate how adding a diverse, complementary set of AETs could improve reliability and cost outcomes in PJM in the near and medium term.

2. METHODS

For this study, Synapse conducted a detailed PJM-wide capacity expansion and resource adequacy analysis, comparing different potential resource deployment scenarios to assess their reliability. We used the EnCompass model to conduct capacity expansion modeling, and the SERVM model to analyze the resource adequacy of the portfolio results from the EnCompass modeling. Figure 3 below illustrates the purpose of each model and how they interact.

Figure 3. Pairing capacity expansion and resource adequacy models to study reliability in PJM



We modeled two scenarios: an "Advanced Policy" scenario and a "Status Quo" scenario. The Advanced Policy scenario simulates a policy future that allows for accelerated, yet realistic, deployment of AETs. The Status Quo scenario simulates lower deployment of AETs, based on historical resource deployment trajectories and consistent with current policy constraints.

2.1. Capacity Expansion Modeling Methods

To determine the resources available to contribute to reliability, we first conducted unit-level, PJM-wide capacity expansion modeling from 2025 through 2035, using the EnCompass model to produce resource portfolios for each scenario. For both scenarios, we used the PJM 2025 load forecast report as the basis for the load forecast. We used this capacity expansion analysis to assess the impacts of additional AET availability on resource builds, generation, system costs, and carbon dioxide (CO_2) emissions.

Assumptions on available-to-build resources

To ensure our scenarios contain realistic assumptions on the quantity of resources that could reasonably come online in the 2025–2035 period, we developed build limits based on current PJM queue data and historical resource deployment rates. A build limit is a maximum amount of a resource, in megawatt (MW) terms, that the model is allowed to build. It does not specify *how much* of the resource to build; instead, the model determines the optimal amount, factoring in load, resource costs, and constraints such as the build limit.

We used consistent resource cost assumptions across the two scenarios. Our resource cost forecasts rely on publicly available data from the National Laboratory of the Rockies (NLR) Annual Technology Baseline (ATB).[30]

Advanced energy technologies (AETs)

Large-scale AET resources (solar, energy storage, and onshore and offshore wind):

By 2030:

- In both scenarios, all large-scale resources that are currently in the "under construction" phase of PJM's queue, and 90 percent of resources that are currently in the "engineering and procurement" phase, are built (if economic to do so) by 2030.[31,32] Both scenarios assume that the Dominion offshore wind project currently under construction is completed by 2030. We also assume that all the selected RRI resources come online according to PJM's expected timeline.
- In the Status Quo scenario, the proportion of large-scale AET projects that can progress from "active" to "online" is based on historical resource advancement rates.
- In the Advanced Policy scenario, the share of large-scale AET projects that progress from the "active" phase to "online" (operating) by 2030 is based on an advancement rate that is double the historical resource advancement rates.[33] As a result, more resources are available to be added by 2030.

2031–2035:

---

[30] National Laboratory of the Rockies. "2024 Electricity ATB Technologies and Data Overview." Available at: https://atb.nrel.gov/electricity/2024/index. For all new resources, we use the Moderate cost trajectory.

31 The PJM interconnection queue phases are (from least to most advanced): active (project is waiting for interconnection service agreement); engineering and procurement (project has received an interconnection agreement and is conducting more detailed engineering study); under construction (physical construction has begun); and online (project is operating). Projects can also be classified as withdrawn or deactivated.

32 Lawrence Berkely National Lab. April 2024. "Queued Up: 2024 Edition," p 30. Available at: https://emp.lbl.gov/sites/default/files/2024-04/Queued%20Up%202024%20Edition_R2.pdf

33 Active resources are limited to those that have entered the queue since 2019 and have an expected online date by 2030.

- In the Advanced Policy scenario, the model allows increasing quantities of large-scale AET projects to be built, reflecting improvements to the interconnection queue process and permitting policies. The model can select to build additional offshore wind projects.
- In the Status Quo scenario, the model has lower annual build limits on large-scale AET projects, reflecting a policy and planning environment that limits their deployment. Compared with the Advanced Policy scenario, the Status Quo scenario can add 50 percent less capacity of each resource type in 2031–2035. The model cannot select to build additional offshore wind projects.

Behind-the-meter solar: Both scenarios rely on projections from PJM's load forecast to define behind-the-meter (BTM) solar adoption. The Advanced Policy scenario uses PJM's 2025 "Accelerated" scenario for BTM solar, which reflects a favorable policy environment, while the Status Quo scenario uses the "Inflated Costs" scenario, which reflects the current policy environment, with tariffs on materials used in the solar supply chain.[34,35] Details on resulting resource quantities can be found in Section 2.2.

Demand response and DER-enabled load flexibility: The scenarios also differ in terms of other modeled distributed energy resources (DERs) besides BTM solar. The Advanced Policy scenario assumes that by 2030, there are enough DERs, including demand response (DR) resources, to reduce peak load by 17 percent (with this level reaching 22 percent by 2035).[36,37] A 17 percent reduction in 2030 peak load equates to about 31 GW. The Status Quo scenario maintains existing DR deployment levels through 2035, at approximately 8 GW. The Advanced Policy Scenario models an ambitious quantity of load flexibility resources within the range of technical potential for load flexibility that has been modeled in recent studies on New York and California.[38]

In the Advanced Policy scenario, we modeled an aggregated set of new load flexibility resources, assumed to consist of residential and commercial air conditioning; commercial refrigeration systems; residential water heating, dishwashing, and clothes drying; vehicle-to-grid programs; and managed electric vehicle charging.[39] Other resources could provide additional benefits. We did not specifically model BTM storage or account for export from stationary or electric vehicle batteries due to a lack of information about dispatch parameters.

---

[34] The "Inflated Costs" scenario is reflective of the policy and cost environment for distributed solar given policy changes during 2025.

[35] S&P Global Commodity Insights. November 4, 2024. PJM Solar and Battery Forecast 2024. Available at: https://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/las/2024/20241125/20241125-reference---item-03-spglobal---pjm-dg-forecast.pdf

[36] This total includes the 7,900 MW of existing DR resources (which are also in the Low Deployment case) as well as new DERs.

[37] This includes data center load.

[38] Hledik, R., K. Peters, S. Edelman. April 2024. California's Virtual Power Potential: How Five Consumer Technologies Could Improve the State's Energy Affordability. Brattle Group for GridLab. Available at: https://www.brattle.com/wp-content/uploads/2024/04/Californias-Virtual-Power-Potential-How-Five-Consumer-Technologies-Could-Improve-the-States-Energy-Affordability.pdf and Brattle Group. January 2025. New York's Grid Flexibility Potential. Available at: https://www.brattle.com/wp-content/uploads/2025/02/New-Yorks-Grid-Flexibility-Potential-Volume-I-Summary-Report.pdf

[39] Sun, Y., P. Jadun, B. Nelson, M. Muratori, C. Murphy, J. Logan, T. Mai. 2020. Electrification Futures Study. National Renewable Energy Laboratory. Available at: https://docs.nrel.gov/docs/fy20osti/73336.pdf.

We modeled some of these resources as participating in PJM's Emergency Load Response program (meaning they had a high dispatch cost around $1,000/MWh), and others as participating in PJM's Economic Demand Response program (meaning their dispatch cost was based on marginal costs).[40,41]

Energy efficiency: The Advanced Policy scenario assumes that all PJM states adopt an energy efficiency trajectory that is aligned with New Jersey, the PJM state that is leading the region in terms of energy efficiency. The Status Quo scenario assumes no incremental energy efficiency beyond the baseline levels included in PJM's 2025 load forecast. As a result, in the Advanced Policy scenario, systemwide energy load in 2030 is 17 TWh (1.5 percent) lower, and in 2035, it is 51 TWh (3.8 percent) lower.[42] This translates to a peak load reduction of 3 GW (2 percent) in 2030 and 10 GW (4 percent) in 2035.[43]

Advanced transmission technologies: The Advanced Policy scenario allows the model to build advanced transmission technology (ATT) projects at congested transmission connections starting in 2028 if the model deems them to be economic additions. Synapse modeled two technologies that can increase transmission line transfer capacity: reconductoring and dynamic line ratings.[44]

- *Reconductoring* involves replacing power lines with advanced conductors that can handle a greater load. We assume that reconductoring projects can increase transmission line transfer capacities by 34 percent, at a cost of $500,000 per mile.[45]
- *Dynamic line rating (DLR)* improvements involve installing sensors on transmission lines so that grid operators can monitor local weather conditions and dynamically adjust the rated transfer capacity of a transmission line accordingly. This technology enables grid operators to increase the line ratings when the weather allows—instead of always using the lowest, most conservative ratings—and take advantage of unused transmission capacity. We assume that DLR projects can increase transmission line transfer capacities by 10 percent, at a cost of $50,000 per mile.[46]

---

[40] Monitoring Analytics. 2025. Quarterly State of the Market Report for PJM: January through June. Page 382. Available at: https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2025/2025q2-som-pjm-sec6.pdf

[41] Murphy, S., C. Miller, J. Deason, D. Dombrowski, P. Awuah. August 2024. The State of Demand Flexibility Programs and Rates. Lawrence Berkeley National Laboratory. Available at: https://eta-publications.lbl.gov/sites/default/files/df_programs_and_rates_draft_final_20240814.pdf

[42] Data based on information available from EIA Form 861. See: U.S. Energy Information Administration. "Electricity." Available at: https://www.eia.gov/electricity/data/eia861/). Energy efficiency trajectories developed using U.S. EPA's Energy Savings and Impacts Scenario Tool. See: United States Environmental Protection Agency. "Energy Savings and Impacts Scenario Tool (ESIST)." Available at https://www.epa.gov/statelocalenergy/energy-savings-and-impacts-scenario-tool-esist

[43] In this analysis, we assume that energy efficiency measures have load shapes resembling conventional load.

[44] While these are the only types of ATTs that we modeled, other options exist (e.g., advanced power flow controls, topology optimization).

[45] Brattle. 2025. "Incorporating GETs and HPCs into Transmission Planning Under FERC Order 1920." Page 38. Available at: Report__Incorporating-GETs-and-HPCs-Under-FERC-Order-1920__April-21-2025.pdf

[46] Ibid.

Other assumptions

Beyond the assumptions about AET deployment, the assumptions in the two scenarios are the same. All other variables, including deployment assumptions on new natural gas resources, fuel prices, and load growth (before considering energy efficiency) are held constant across the two scenarios unless otherwise specified. In terms of natural gas, both scenarios use the same build limits for new gas plants, based on data from PJM's interconnection queue.[47] We also model all gas RRI resources, assuming they will come online by their currently expected commercial operation dates.

2.2. Capacity Expansion Resource Build Outputs

Table 4 shows the capacity additions of each resource type selected by the model in each scenario. The resource mix in each scenario satisfies demand in all hours of the "typical" year that was modeled. We observe that as a result of increasing loads, there are few differences in terms of resource retirements through 2030, with most modeled resource retirements through that year resulting from already announced plans.

---

[47] However, using the same build limit across two scenarios does not mean that the model chooses to build the same amount of natural gas in each scenario.

Table 4. Modeled new resource build outputs in PJM by 2030 and 2035 under Status Quo and Advanced Policy Scenarios (nameplate GW)[48]

Resource	2025	Net additions, cumulative 2025-2030			Net additions, cumulative 2025-2035		
		Status Quo	Advanced Policy	Delta between scenarios	Status Quo	Advanced Policy	Delta between scenarios
Advanced energy technologies							
Solar	**28**	**50**	**68**	**18**	**82**	**160**	**78**
BTM solar	*12*	*4*	*11*	*7*	*9*	*20*	*11*
Large-scale solar	*17*	*45*	*57*	*11*	*73*	*140*	*67*
Onshore wind	**12**	**7**	**7**	**0**	**9**	**14**	**6**
Offshore wind	**0**	**4**	**4**	**0**	**4**	**7**	**3**
Battery storage	**2**	**11**	**21**	**10**	**34**	**88**	**54**
DERs	**7**	**0**	**28**	**28**	**0**	**45**	**45**
EE*	**0**	**0**	**3**	**3**	**0**	**10**	**10**
ATTs	**0**	**0**	**3**	**3**	**0**	**3**	**3**
Subtotal	**49**	**72**	**134**	**62**	**130**	**327**	**197**
Coal and gas							
Gas	**102**	**8**	**7**	**-1**	**39**	**19**	**-19**
Existing gas	*102*	*-1*	*-2*	*-1*	*-3*	*-19*	*-16*
New gas	*0*	*9*	*9*	*0*	*42*	*39*	*-3*
Coal	**39**	**-16**	**-19**	**-3**	**-17**	**-32**	**-15**
Subtotal	**141**	**-8**	**-12**	**-4**	**22**	**-12**	**-34**
Other resources							
Nuclear**	**35**	**1**	**1**	**0**	**1**	**1**	**0**
Other***	**10**	**0**	**0**	**0**	**0**	**0**	**0**
Subtotal	**44**	**1**	**1**	**0**	**1**	**1**	**0**
Grand total	**234**	**65**	**123**	**58**	**153**	**315**	**163**

** EE capacity numbers are incremental to baseline EE included in PJM's load forecast.*

*** Nuclear refers mostly to Three Mile Island repowering but includes small modular reactors as well.*

**** Other includes hydro, biomass, landfill gas and other existing resources.*

---

[48] Subtotals and deltas may not exactly match the difference between previous rows and columns due to rounding.

As might be anticipated, the Advanced Policy scenario yields greater AET deployment than the Status Quo scenario. However, the key point is that when more AETs are made available, the model finds them to be economic and therefore, builds them. In summary, Table 4 captures the following resource builds and deltas between the two modeled scenarios:

Advanced energy technologies

- **Large-scale AET resources (solar, energy storage, and onshore and offshore wind):** Between 2025 and 2030, the Advanced Policy scenario yields 11 GW (25 percent) more large-scale solar than the Status Quo scenario and more than twice as much storage (21 GW compared with 11 GW). This trend accelerates in 2031–2035. The Advanced Policy scenario projects 67 GW (92 percent) more large-scale solar by 2035, and more than double the storage, than the Status Quo scenario. The Advanced Policy scenario also yields 6 GW (65 percent) more onshore wind by 2035, and 3 GW (61 percent) more offshore wind.

- **Behind-the-meter solar:** The Advanced Policy scenario projects 20 GW by 2035, while the Status Quo scenario includes just under half that amount (9 GW) due to higher projected costs.

- **Demand response and DER-enabled load flexibility:** Reaching the target level of peak load shaving, the Advanced Policy scenario deploys an additional 28 GW of DERs and DR by 2030 and a cumulative 45 GW by 2035 relative to the Status Quo scenario.

- **Energy efficiency:** The Advanced Policy scenario projects an additional 3 GW of energy efficiency gains beyond the baseline in PJM’s load forecast by 2030, and 10 GW by 2035.

- **Advanced transmission technologies:** In the Advanced Policy scenario, the model deploys all the DLR projects available to it, as well as two of seven reconductoring projects. The DLR upgrades increase the transfer capacity between some PJM zones by 10 percent, totaling 1,442 MW, and the reconductoring upgrades increase the transfer capacity in some PJM zones by 34 percent, totaling 1,903 MW in upgrades. Overall, this means an intra-regional increase in transfer capacity of 3,345 MW.

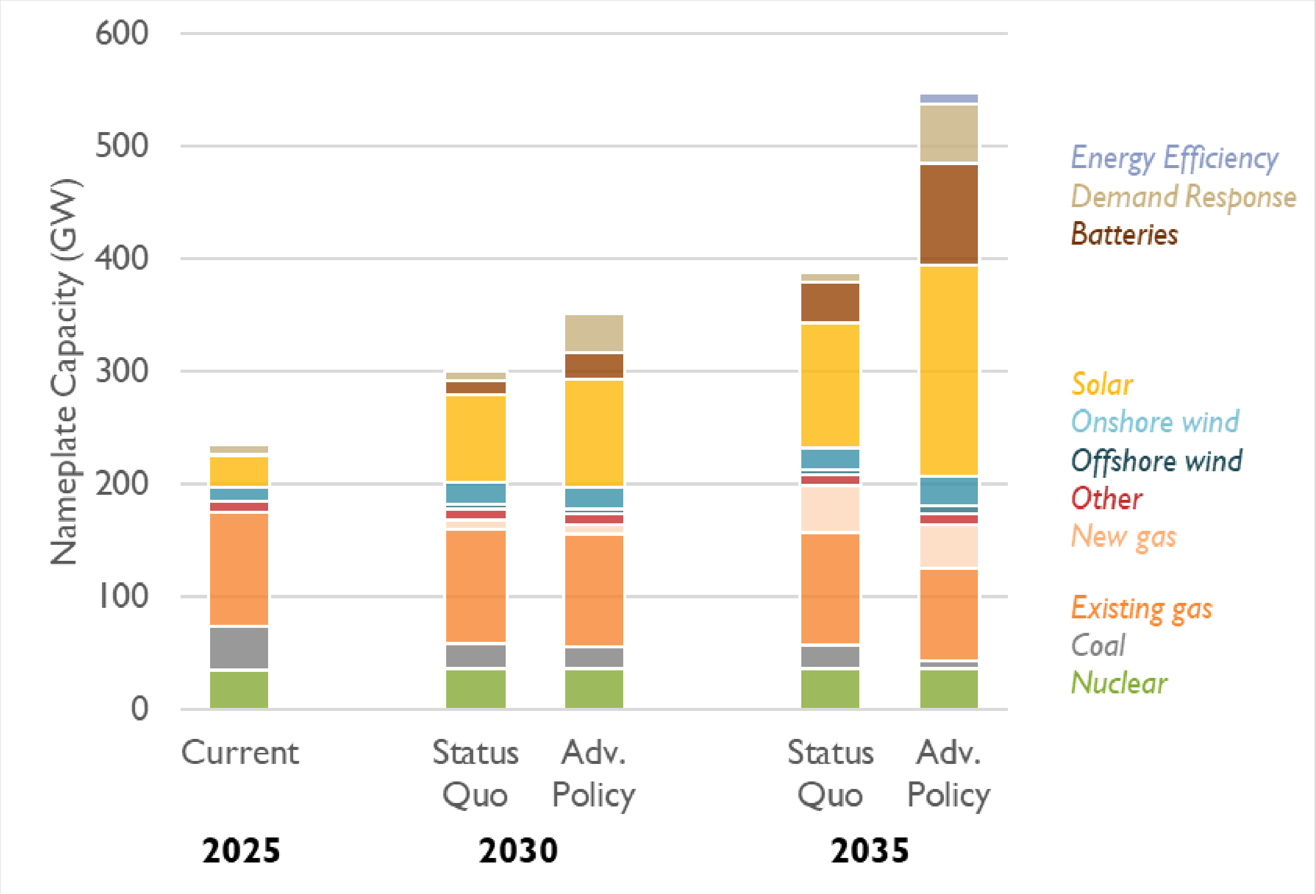
Coal and gas

- **Natural gas:** In the Advanced Policy case, increased availability of AETs enables a greater number of older and less efficient gas plants to be retired by 2035. The availability of more economic alternatives also results in the Advanced Policy scenario deploying 3 GW less of new gas capacity by 2035 than the Status Quo scenario—even though the same amount of new gas capacity is assumed to be available to build.

- **Coal retirements:** The Advanced Policy scenario retires more coal capacity than the Status Quo scenario does by 2035.

Figure 4 summarizes the cumulative resources deployed under the two scenarios.

Figure 4. Total installed capacity in PJM in 2025, 2030, and 2035



2.3. Resource Adequacy Modeling Methods

The EnCompass model builds resource portfolios that meet demand during a typical year. We then use the SERVM model to rigorously evaluate a portfolio's ability to meet demand across a wide range of weather and other reliability-relevant conditions. To compare the reliability performance of the two modeled scenarios, Synapse conducted resource adequacy modeling using SERVM. SERVM is the industry standard reliability model and is used to evaluate roughly three-quarters of U.S. electricity demand. Synapse used SERVM to analyze the reliability performance of both scenarios in two test years: 2030 and 2035.

To evaluate the performance of each scenario's resource portfolios during a test year, SERVM uses the resource portfolio outputs and load input assumptions from the EnCompass model for the given scenario to model resource dispatch under a range of conditions. We model 30 different projections of the reliability test year's weather and five different levels of load forecast error (varied relative to the load modeled in EnCompass). For each combination of weather and load forecast error, we model five unique power plant forced outage scenarios. In total, this results in 750 unique combinations of weather, load, and forced outage conditions. Each individual combination has a different probability of occurring (for example, cases with large forecast errors are assumed to be less probable).

Forced outage probabilities for natural gas and coal power plants are correlated with ambient temperature. At extremely hot and cold temperatures, these plants have a higher likelihood of being forced offline. We modeled this correlation between extreme temperatures and increased forced outage rates using academic research that relied on PJM Generator Availability Data System data.[49]

Finally, the reliability performance of each of the 750 different combinations is paired with the probabilities of each one occurring to produce an expected value (or probability-weighted average) of the different reliability metrics (e.g., LOLE) for each scenario, and each test year. In this way, we use SERVM to test and compare the reliability of different portfolios under the exact same weather and load uncertainty conditions.

---

[49] Murphy, S., L. Lavin, J. Apt. 2020. "Resource adequacy implications of temperature-dependent electric generator availability." *Applied Energy Journal*. Available at: https://doi.org/10.1016/j.apenergy.2019.114424

3. RELIABILITY RESULTS

Our reliability modeling results indicate that a resource portfolio with more AETs can offer superior performance in terms of reduced frequency, duration, and magnitude of reliability events, compared with a resource portfolio without those additional resources. In other words, a resource portfolio with more AETs can reduce or avoid power outages for customers in the PJM region. As a logical gut-check on the modeling results, it is worth noting that a resource portfolio with more AETs is a more diverse resource portfolio, given the relatively low penetration of most AETs in the PJM footprint today, and thus increased deployment will tend to compensate for correlated failures of the existing resource fleet.

3.1. Increased Deployment of AETs Avoids Power Outages in the Near and Long Term

Our reliability modeling shows that in both 2030 and 2035, the Advanced Policy scenario has fewer power outages, with shorter durations, and that affect fewer customers than the Status Quo scenario.

Advanced energy technologies make the PJM grid more reliable in 2030

Throughout 2025, PJM members and the Board raised concerns about near-term resource adequacy concerns due to projected supply–demand imbalances.[50] Our analysis demonstrates that AETs are a viable solution for addressing these concerns due to their short construction timelines and the many projects already in PJM's interconnection queue. We find that deploying an accelerated, yet realistic, amount of advanced energy technologies could address near-term resource adequacy issues by 2030.

In 2030, the Status Quo scenario has an expected LOLE of 1.6 days per year—that is, 16 times the maximum of 0.1 days per year under PJM's reliability performance standard (see Table 5 and Figure 5). The expected number of hours with unserved energy is 3–4 hours per year, and the expected duration of an event is 88 minutes. The expected maximum annual event magnitude is 9.3 GW, which is equivalent to 5 percent of PJM's projected peak load in 2030. To get a sense of the scale of this type of outage, if an event of this magnitude exclusively affected residential customers, about 7.6 million households in the PJM region would lose power for one hour.[51] That is nearly four times the number of PJM customers affected by the 2003 Northeast Blackout. While the 2003 Blackout was longer and was

---

[50] PJM. August 2025. "PJM Board Fast-Tracks Effort to Reliably Serve Large Loads." Available at: https://insidelines.pjm.com/pjm-board-fast-tracks-effort-to-reliably-serve-large-loads/

[51] This metric is a heuristic to approximate the number of households that would be affected by an outage. It divides the maximum expected event magnitude (MW) by an estimate of energy used hourly per household and assumes the outage would only affect residential customers.

driven by transmission system outages, not the resource adequacy issues that are the focus of this study, it provides a useful reference for contextualizing the magnitude of this type of event.[52]

Table 5. Summary of expected PJM reliability performance by scenario in 2030 and 2035

Year	Scenario	Outage frequency (LOLE)	Outage duration	Outage max. magnitude (max. hourly unserved load)
2030	**Status Quo**	**1.6 days per year** (**16x worse** than PJM standard of 0.1 days per year)	88 minutes	9.3 GW (5 percent of PJM peak load) Outage for 7.6 million customers for 1 hour
	Advanced Policy	**1 day per 25 years** (**2.5x better** than PJM standard)	7 minutes	1.2 GW (0.6 percent of PJM peak load) Outage for 963,000 customers for 1 hour
2035	**Status Quo**	**1 day per 2 years** (**4x worse** than PJM standard)	55 minutes	7.4 GW (3 percent of PJM peak load) Outage for 6.0 million customers for 1 hour
	Advanced Policy	**1 day per 70 years** (**7x better** than PJM standard)	2 minutes	0.9 GW (0.4 percent of PJM peak load) Outage for 717,000 customers for 1 hour

Figure 5 illustrates the 2030 reliability performance of the two scenarios using the four main reliability metrics. Each chart shows the results for one metric (LOLE, LOLH, annual unserved energy, and maximum annual event magnitude). In a given chart, the bold circle for each scenario is the expected value. Each dot around the expected value is a simulated year-load forecast pair. The sometimes-wide distribution of dots is indicative of tail-end events (e.g., individual simulations with much higher LOLE).

---

[52] On August 14, 2003, a few outages—at transmission lines in Ohio and Indiana and a coal plant in Ohio—and a lack of sound system management and coordination triggered a cascading outage that interrupted electric service to 45 million people in the U.S. and 10 million in Canada for 4–36 hours. Most of New York state lost power. Within PJM, this outage affected over 2 million customers across New Jersey, Ohio, and Pennsylvania. The causes were predominantly associated with process, warning system, and management issues rather than power plant outages.

"Major power outage hits New York, other large cities." August 14, 2003. CNN. Available at: https://www.cnn.com/2003/US/08/14/power.outage/

U.S.-Canada Power System Outage Task Force. April 2004. "Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations." Available at: https://www.energy.gov/sites/prod/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf

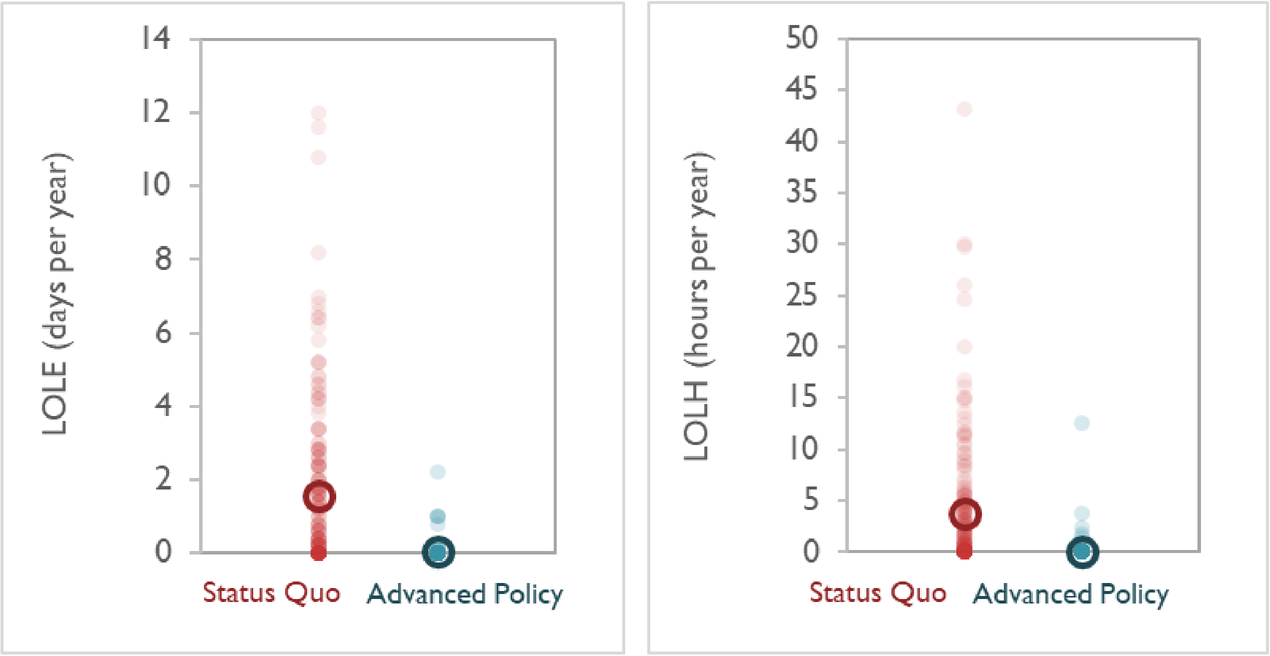
Freed, Matt. "Pennsylvania hit by blackout, but just near Erie." August 15, 2003. *Pittsburgh Post-Gazette*. Available at: https://www.post-gazette.com/news/nation/2003/08/15/Pennsylvania-hit-by-blackout-but-just-near-Erie/stories/200308150020

Michigan Public Service Commission. November 2003. "Michigan Public Service Commission Report on August 14th Blackout." Available at: https://www.michigan.gov/-/media/Project/Websites/mpsc/regulatory/reports/mpsc_blackout.pdf

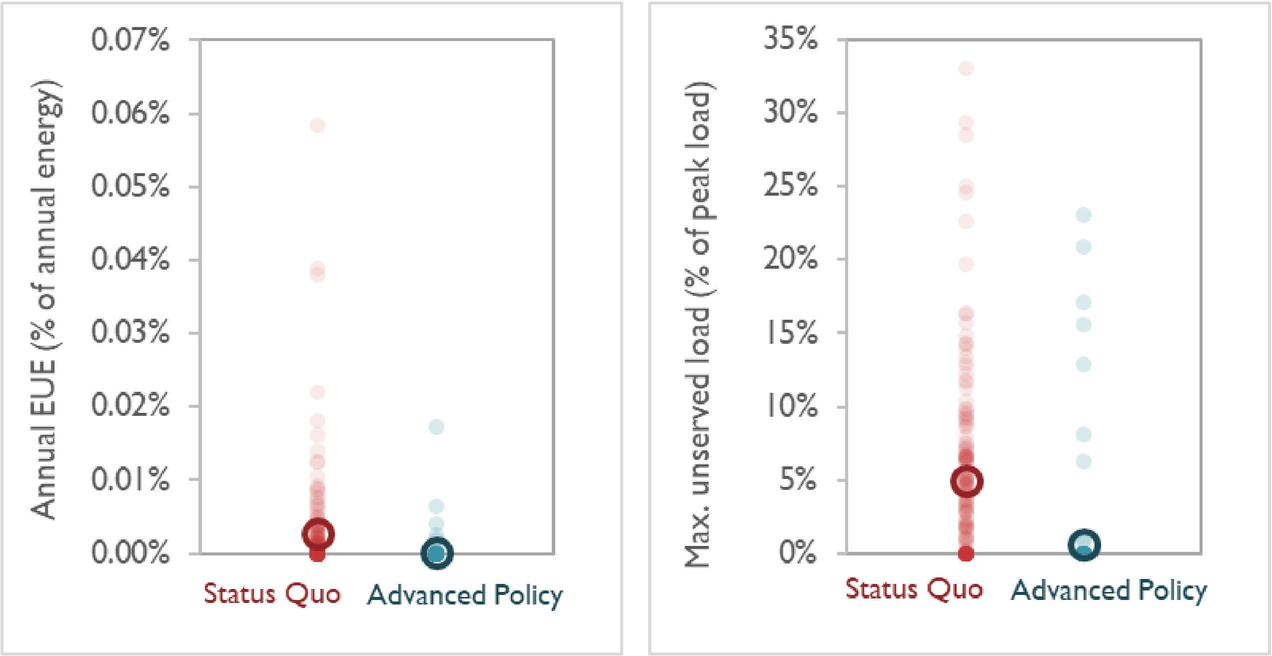
Mytnick, C., E. Ward, J. Vickers, L. Thompson. August 14, 2018. "The Blackout of 2003: By the Numbers." *Cleveland Magazine*. Available at: https://clevelandmagazine.com/articles/the-blackout-of-2003-by-the-numbers/

Figure 5. Reliability performance for the Status Quo and Advanced Policy scenarios in PJM in 2030

Expected number of outage days | Expected hours with unserved energy



Expected unserved energy | Expected magnitude of outages



Each dot represents a simulated year-load forecast pair. Circles are the expected values (probability-weighted averages).

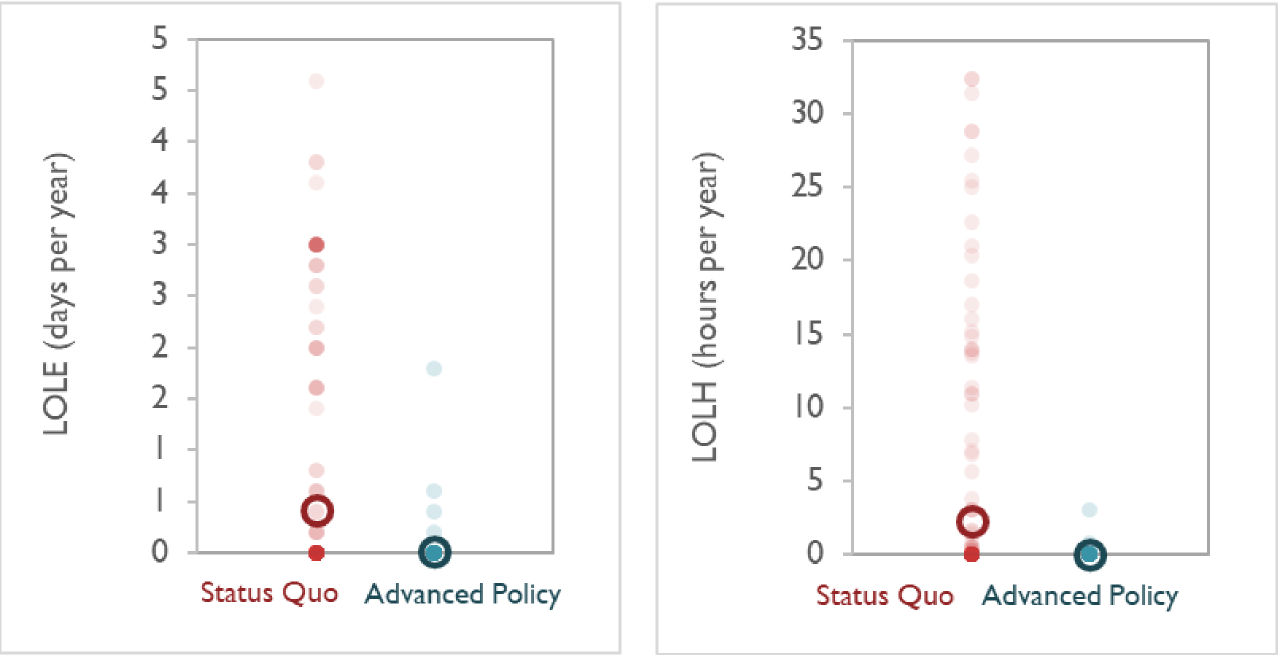
In contrast, the Advanced Policy scenario exceeds the reliability performance standard established by PJM. Increased deployment of AETs under this scenario would enable PJM to avoid the majority of the power outages that occur in the Status Quo scenario, with LOLE of just 0.04 days in 2030, or one day in 25 years. This is 2.5 times better than the PJM standard of one day in 10 years. The expected number of hours with unserved energy is one hour per year, and the expected duration of an event is just 7 minutes. The expected maximum annual event magnitude is 1.2 GW, which is equivalent to 0.6 percent of PJM peak load in 2030. If this outage exclusively affected residential customers, about 963,000 PJM households would lose power for one hour. This is 87 percent fewer households than would be affected by power outages in the Status Quo scenario.

Again in 2035, only the Advanced Policy scenario meets PJM's reliability threshold

For 2035, the modeling results show a more reliable system overall under both scenarios, but once again, only the Advanced Policy scenario meets or exceeds the PJM reliability standard of 0.1 LOLE. In other words, with higher levels of AET penetration, PJM can maintain system-level resource adequacy over time. Although individual resources may be weather-dependent, this outcome demonstrates that collectively, the set of AETs modeled can serve load in the PJM region more effectively under a wide range of weather, load, and forced outage conditions than a grid with fewer AETs.

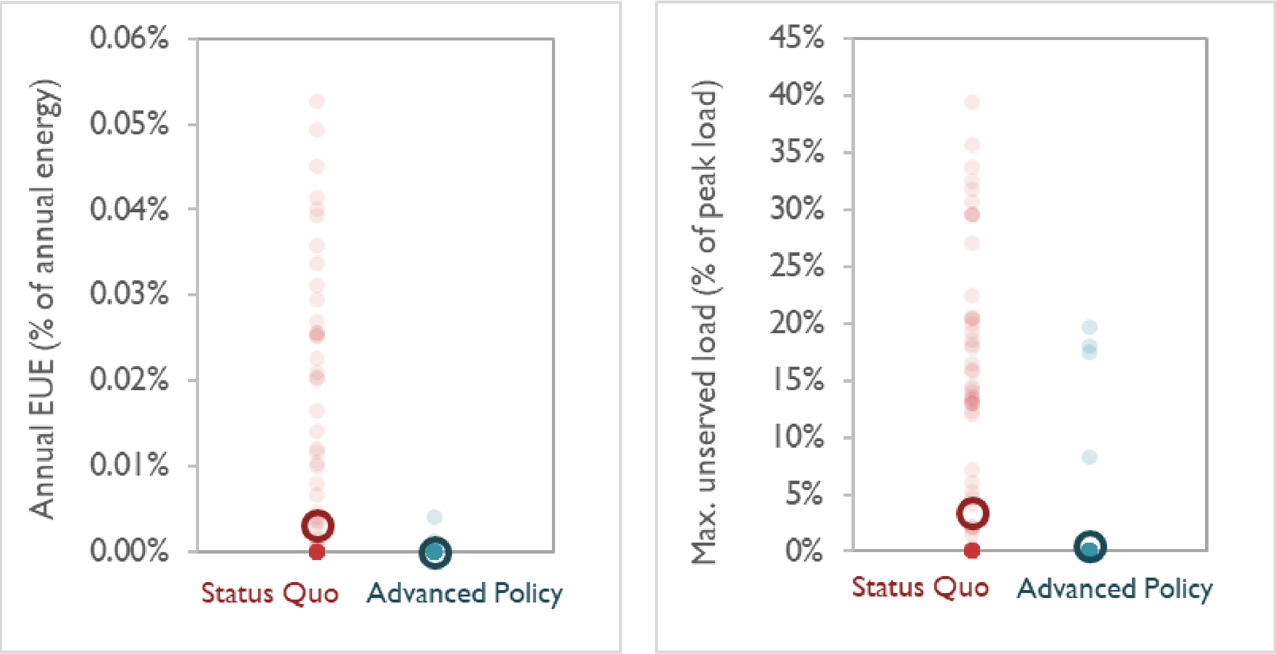
In 2035, the Status Quo scenario has LOLE of 0.4 days per year—much better than in 2030, but still four times worse than the PJM standard (see Figure 6). In contrast, the Advanced Policy scenario exceeds the PJM reliability performance standard by an even greater margin, with reliability issues expected just one day in 70 years. That is seven times better than the PJM standard of one day in 10 years. Data for the other metrics are shown in Table 5.

Figure 6. Reliability performance for the Status Quo and Advanced Policy scenarios in PJM in 2035



Expected number of outage days

Expected hours with unserved energy



Expected unserved energy

Expected magnitude of outages

3.2. AETs Mitigate Risk During Both Winter and Summer Periods

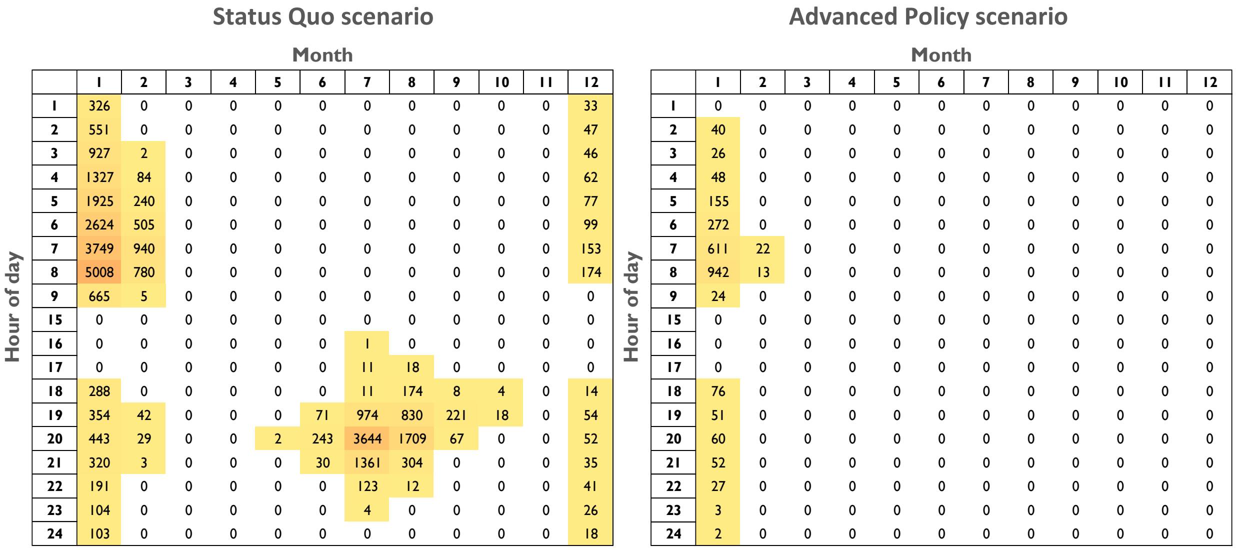
In the winter, the Advanced Policy scenario has fewer and smaller outages than the Status Quo scenario

Consistent with PJM's own modeling, our analysis finds that winter has recently become the dominant season for bulk power system-related reliability issues.[53] We find that both scenarios have expected unserved energy during the winter, particularly during January mornings, but that the Status Quo scenario yields much larger outages (i.e., more unserved energy) and at many additional times throughout the winter.

In 2030, the Status Quo scenario results in unserved energy throughout most of the day (except for midafternoons) in December, January, and February (see Figure 7). The unserved energy is highest during January mornings, from 4 to 9 AM. The Advanced Policy scenario results in no unserved energy in December, much smaller amounts of unserved energy in January compared with the Status Quo scenario, and virtually no unserved energy in February.

In 2035, the winter reliability of the Status Quo scenario deteriorates (unserved energy is much higher) across December, January, and February (see Figure 8). Meanwhile, the winter reliability of the Advanced Policy scenario is much improved from 2030 due to higher resource deployment under this scenario, widening the gap between the two scenarios.

Figure 7. Heatmaps showing unserved energy (MWh) in PJM by month and hour, 2030



Status Quo scenario

	1	2	3	4	5	6	7	8	9	10	11	12
1	326	0	0	0	0	0	0	0	0	0	0	33
2	551	0	0	0	0	0	0	0	0	0	0	47
3	927	2	0	0	0	0	0	0	0	0	0	46
4	1327	84	0	0	0	0	0	0	0	0	0	62
5	1925	240	0	0	0	0	0	0	0	0	0	77
6	2624	505	0	0	0	0	0	0	0	0	0	99
7	3749	940	0	0	0	0	0	0	0	0	0	153
8	5008	780	0	0	0	0	0	0	0	0	0	174
9	665	5	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
16	0	0	0	0	0	0	1	0	0	0	0	0
17	0	0	0	0	0	0	11	18	0	0	0	0
18	288	0	0	0	0	0	11	174	8	4	0	14
19	354	42	0	0	0	71	974	830	221	18	0	54
20	443	29	0	0	2	243	3644	1709	67	0	0	52
21	320	3	0	0	0	30	1361	304	0	0	0	35
22	191	0	0	0	0	0	123	12	0	0	0	41
23	104	0	0	0	0	0	4	0	0	0	0	26
24	103	0	0	0	0	0	0	0	0	0	0	18

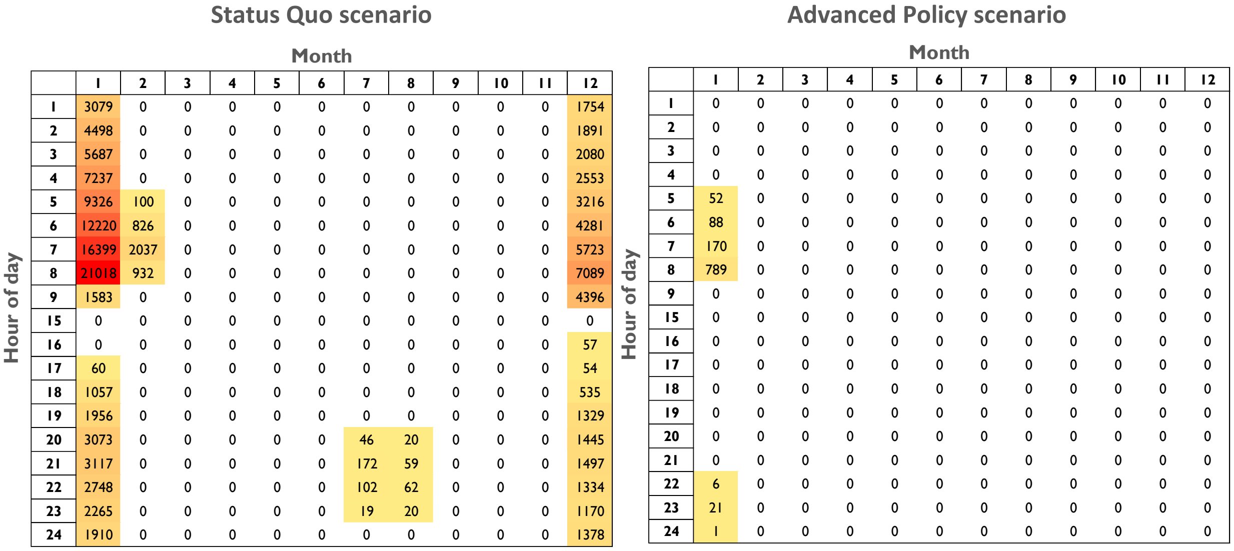
Advanced Policy scenario

	1	2	3	4	5	6	7	8	9	10	11	12
1	0	0	0	0	0	0	0	0	0	0	0	0
2	40	0	0	0	0	0	0	0	0	0	0	0
3	26	0	0	0	0	0	0	0	0	0	0	0
4	48	0	0	0	0	0	0	0	0	0	0	0
5	155	0	0	0	0	0	0	0	0	0	0	0
6	272	0	0	0	0	0	0	0	0	0	0	0
7	611	22	0	0	0	0	0	0	0	0	0	0
8	942	13	0	0	0	0	0	0	0	0	0	0
9	24	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
16	0	0	0	0	0	0	0	0	0	0	0	0
17	0	0	0	0	0	0	0	0	0	0	0	0
18	76	0	0	0	0	0	0	0	0	0	0	0
19	51	0	0	0	0	0	0	0	0	0	0	0
20	60	0	0	0	0	0	0	0	0	0	0	0
21	52	0	0	0	0	0	0	0	0	0	0	0
22	27	0	0	0	0	0	0	0	0	0	0	0
23	3	0	0	0	0	0	0	0	0	0	0	0
24	2	0	0	0	0	0	0	0	0	0	0	0

---

[53] "ELCC Education." PJM. February 21, 2024. Slides 21–23. Available at: https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2024/20240221-special/elcc-education.pdf

Figure 8. Heatmaps showing unserved energy (MWh) in PJM by month and hour, 2035



Status Quo scenario

Month

Hour of day

	1	2	3	4	5	6	7	8	9	10	11	12
1	3079	0	0	0	0	0	0	0	0	0	0	1754
2	4498	0	0	0	0	0	0	0	0	0	0	1891
3	5687	0	0	0	0	0	0	0	0	0	0	2080
4	7237	0	0	0	0	0	0	0	0	0	0	2553
5	9326	100	0	0	0	0	0	0	0	0	0	3216
6	12220	826	0	0	0	0	0	0	0	0	0	4281
7	16399	2037	0	0	0	0	0	0	0	0	0	5723
8	21018	932	0	0	0	0	0	0	0	0	0	7089
9	1583	0	0	0	0	0	0	0	0	0	0	4396
15	0	0	0	0	0	0	0	0	0	0	0	0
16	0	0	0	0	0	0	0	0	0	0	0	57
17	60	0	0	0	0	0	0	0	0	0	0	54
18	1057	0	0	0	0	0	0	0	0	0	0	535
19	1956	0	0	0	0	0	0	0	0	0	0	1329
20	3073	0	0	0	0	0	46	20	0	0	0	1445
21	3117	0	0	0	0	0	172	59	0	0	0	1497
22	2748	0	0	0	0	0	102	62	0	0	0	1334
23	2265	0	0	0	0	0	19	20	0	0	0	1170
24	1910	0	0	0	0	0	0	0	0	0	0	1378

Advanced Policy scenario

Month

Hour of day

	1	2	3	4	5	6	7	8	9	10	11	12
1	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0
5	52	0	0	0	0	0	0	0	0	0	0	0
6	88	0	0	0	0	0	0	0	0	0	0	0
7	170	0	0	0	0	0	0	0	0	0	0	0
8	789	0	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
16	0	0	0	0	0	0	0	0	0	0	0	0
17	0	0	0	0	0	0	0	0	0	0	0	0
18	0	0	0	0	0	0	0	0	0	0	0	0
19	0	0	0	0	0	0	0	0	0	0	0	0
20	0	0	0	0	0	0	0	0	0	0	0	0
21	0	0	0	0	0	0	0	0	0	0	0	0
22	6	0	0	0	0	0	0	0	0	0	0	0
23	21	0	0	0	0	0	0	0	0	0	0	0
24	1	0	0	0	0	0	0	0	0	0	0	0

There are a number of factors that contribute to the concentration of unserved energy risk in winter. The most important factor is the higher forced outage rates of natural gas and coal-fired power plants during cold weather periods. The slow ramp rates of fossil power plants also limit the ability of these plants to respond to weather-related forced outages.[54] This is another reliability limitation of many gas and coal plants compared with fast-acting battery storage resources. Finally, solar generation is reduced in winter, especially in the evenings, which further increases the likelihood of generation shortages.

Although PJM is projected to remain a summer-peaking system throughout the model period, the gap between winter and summer peaks is projected to decrease between 2025 and 2035, primarily due to building electrification.

Overall, the Advanced Policy scenario has less unserved energy than the Status Quo scenario during winter months. The Status Quo scenario relies more heavily on natural gas plants to serve load, and these plants are likelier to trip offline at very low temperatures. This is consistent with recent experience, when natural gas plant forced outages were a large driver of risk during Winter Storm Elliott in 2022 (see case study below).

---

[54] SERVM commits power plants on a day-ahead basis, without insight into future forced outages. When SERVM dispatches power plants, a plant with a long ramp time that not been committed will be unable to quickly respond to a forced outage at another plant, limiting its ability to contribute to system reliability.

Historical Case Study: Winter Storm Elliott

Winter Storm Elliott was a weekend of freezing temperatures, high load, and high levels of forced outages at natural gas and coal plants across the PJM region on December 23–25, 2022. On December 23, the temperature dropped by a record-breaking 29 degrees over 12 hours, and load spiked accordingly.[55] The extreme cold led to high forced generator outages, especially at natural gas plants, due to freezing equipment (e.g., pipes), other equipment issues, and gas supply issues.

The magnitude of the forced outages increased to 47,000 MW, a forced outage rate of **24 percent fleetwide**, during the morning of December 24, the coldest day of the holiday weekend, which had continued high load. That day, 70 percent (33,404 MW) of all outages involved natural gas resources; 16 percent (7,165 MW), coal; and 14 percent (6,390 MW) other resources (oil, nuclear, hydro, wind and solar, in descending order).[56]

In fact, according to PJM, wind and solar resources performed as projected based on wind speeds and solar irradiance, while the **natural gas fleet had disproportionately high outages, with a forced outage rate of 39 percent**.[57]

PJM very narrowly avoided rolling blackouts by issuing calls for energy conservation, activating emergency demand response, and obtaining emergency authorization to run power plants that were not on outage above emissions limits.[58]

Increased deployment of advanced energy technologies mitigates summer risk entirely

Outside of the winter period, only the Status Quo scenario has expected unserved energy. In 2030, this unserved energy occurs during afternoons and evenings (4–11 PM) from May through October, with the most occurring between 8 and 9 PM in July. In 2035, there is much less unserved energy, and it only occurs during evenings (8–11 PM) in July and August.

The expected unserved energy in summer in the Status Quo scenario is due to high loads during these periods, as well as reduced solar generation in the evenings. However, the combination of solar, storage, and other AETs can cover load well into the evening. Our results show that although it has more

---

[55] PJM. April 12, 2023. Winter Storm Elliott Frequently Asked Questions. Available at: https://www.pjm.com/-/media/DotCom/markets-ops/winter-storm-elliott/faq-winter-storm-elliott.ashx

[56] PJM. July 17, 2023. Winter Storm Elliott Event Analysis and Recommendation Report. Page 49. Available at: https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.pdf?ref=blog.gridstatus.io

[57] The outages on December 24 were disproportionate to PJM's total fleet capacity, which is 46 percent gas, 24 percent coal, and 29 percent other (ibid.).

[58] PJM. April 12, 2023. Winter Storm Elliott Frequently Asked Questions. Available at: https://www.pjm.com/-/media/DotCom/markets-ops/winter-storm-elliott/faq-winter-storm-elliott.ashx

solar, the Advanced Policy scenario does not have any outages during the summer. Only the Status Quo scenario results in summer outages caused by the bulk power system.

3.3. AETs Help Provide Reliable Electricity During Extreme Weather Events

This analysis also finds that AETs help to provide reliable electricity during extreme weather and load events, based on a modeled extreme event in summer 2030.

Additional solar, storage, and demand flexibility help the grid maintain reliability during a summer 2030 high load episode

We examined a sample three-day period (July 5–7, 2030) from one of our simulated cases to visualize the role of AETs in meeting hourly demand and maintaining reliability. The maximum temperature during this period is 103°F in the southern part of the PJM region. In the Status Quo scenario, there is insufficient generation to meet demand in the evening hours between 6 and 9 PM on each of the three days. This is shown by the red EUE in Figure 9, which are hours when demand is high as households consume electricity for space cooling, laundry, cooking, and more. Also during these hours, solar output ramps down, and there is not enough battery storage capacity in the Status Quo scenario to meet all demand. Unserved energy means that consumers would lose power, which can be dangerous in extreme heat.[59]

In contrast, in the Advanced Policy scenario, we see no unserved energy during this same three-day period. The additional solar, battery, and demand response capacity in this scenario allow the system to meet load and avoid an outage entirely, even with less gas and coal capacity (see Figure 10). Specifically, the storage flattens the peak load and allows the solar benefits to extend later into the evening. Solar is used to charge battery storage systems in both scenarios, but the Advanced Policy scenario has both more solar and more storage.[60]

---

[59] United States Environmental Protection Agency. “Climate Change Indicators: Heat-Related Deaths.” Available at: https://www.epa.gov/climate-indicators/climate-change-indicators-heat-related-deaths

[60] In the charts below, “solar” refers to both large-scale and BTM solar. Overall demand is slightly lower in the Advanced Policy scenario due to that scenario’s higher deployment of energy efficiency.

Figure 9. Status Quo scenario resources, load, and unserved energy (EUE) during the weekend of July 5–7, 2030

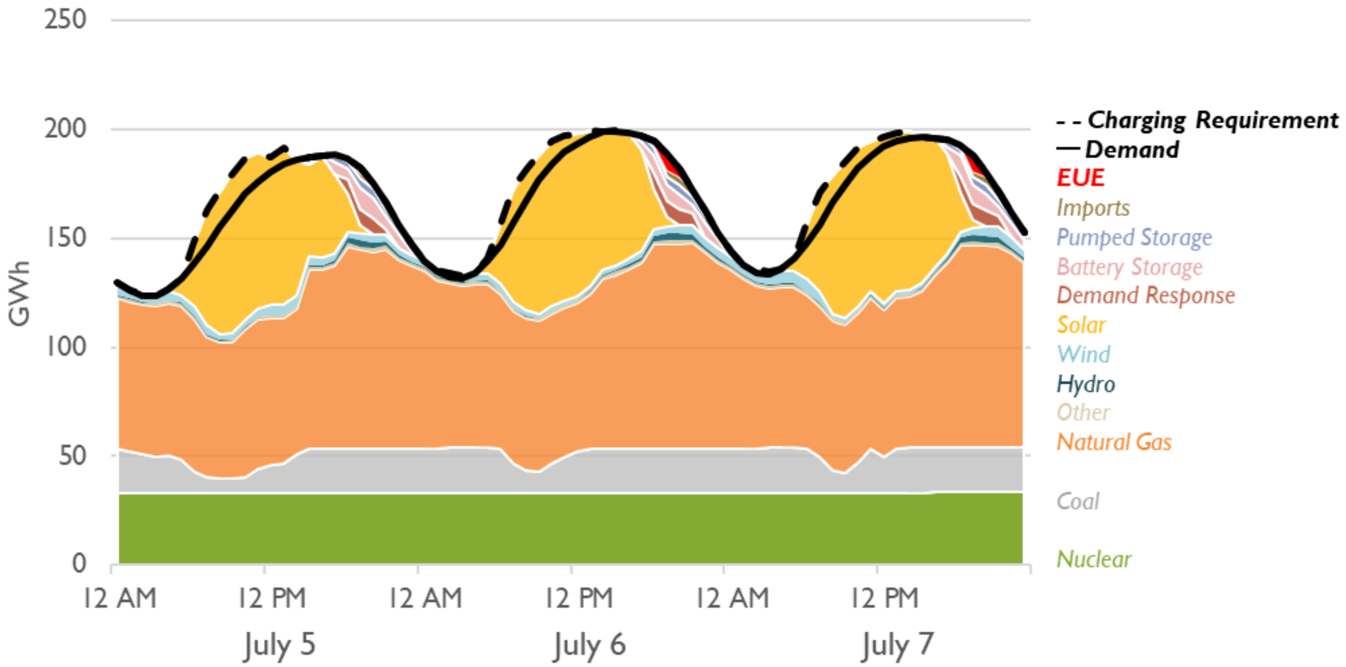
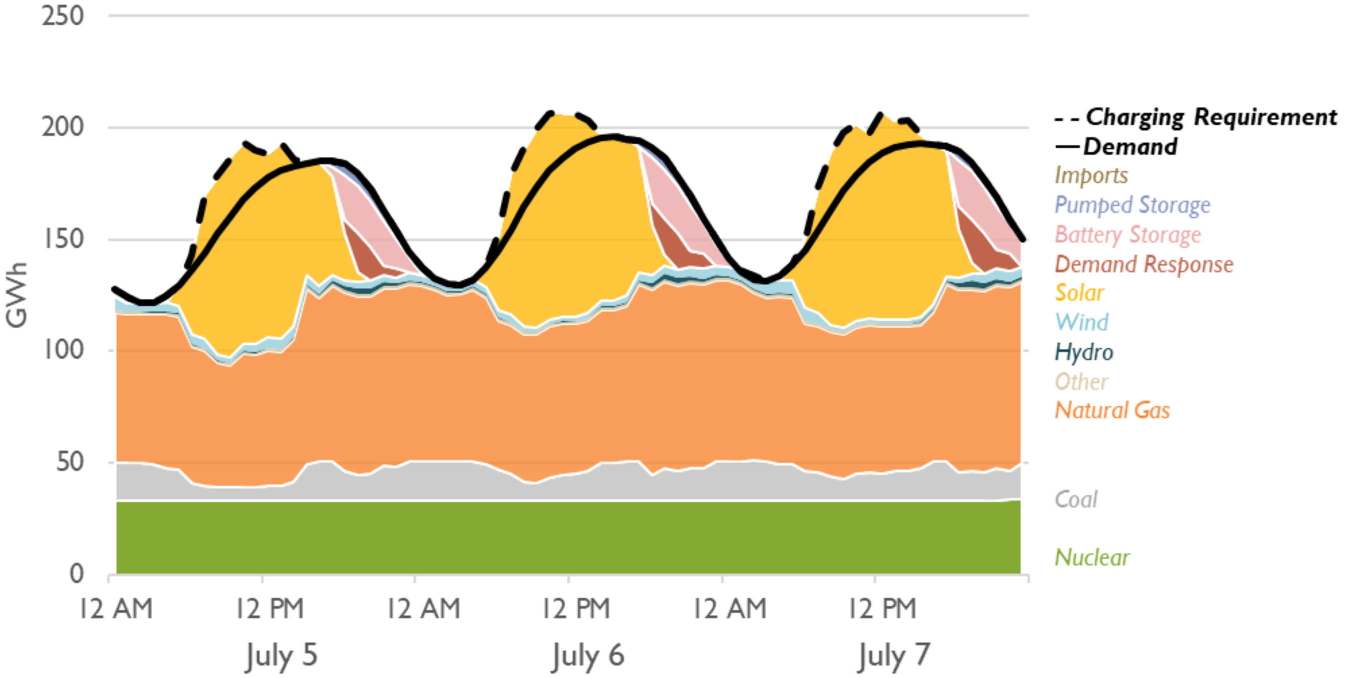


Figure 10. Advanced Policy scenario resources and load during the weekend of July 5–7, 2030



AETs help maintain grid reliability during a January 2035 cold morning

We also examined a single winter day (January 7, 2035) from one of our simulated cases to visualize the role of AETs in maintaining reliability during a cold snap. The minimum temperature during this period is -7°F in the western part of the PJM region. In the Status Quo scenario, there is insufficient generation to meet demand between 4 and 9 AM, as shown by the EUE in Figure 11. These are very cold hours when demand starts to increase as the day begins. In the Advanced Policy scenario, we see no EUE. The additional battery storage, demand response, and wind power allow the system to avoid an outage, even though the scenario deploys less gas during these hours than the Status Quo scenario (see Figure 12).

Figure 11. Status Quo scenario resources, load, and unserved energy (EUE) on January 7, 2035

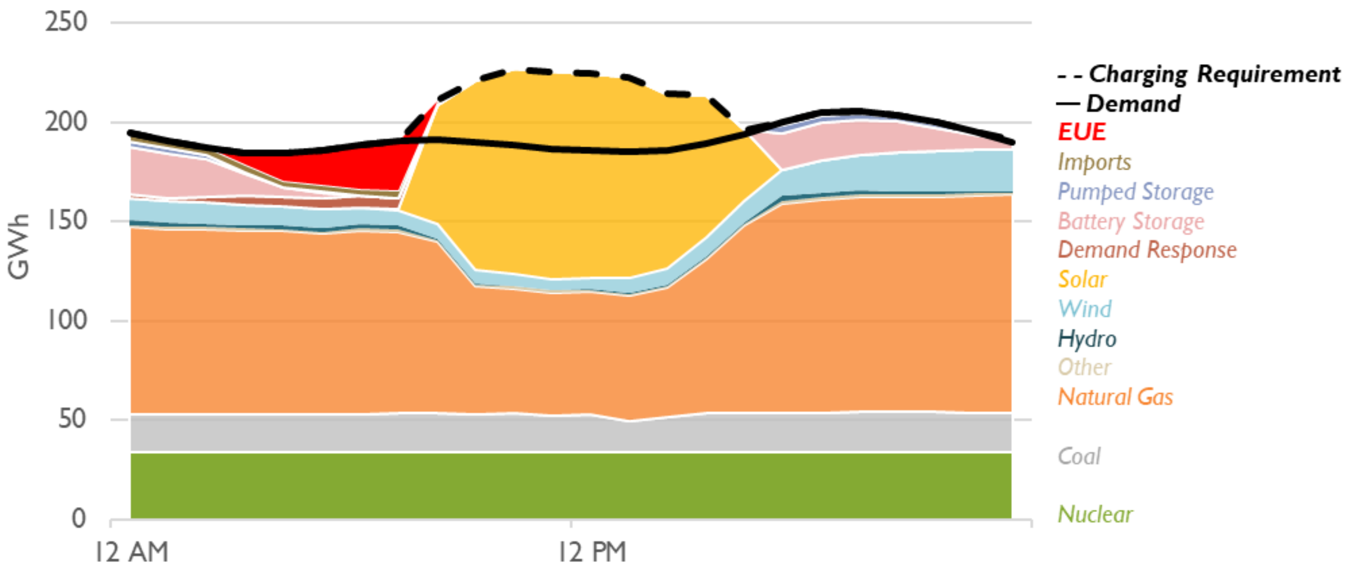
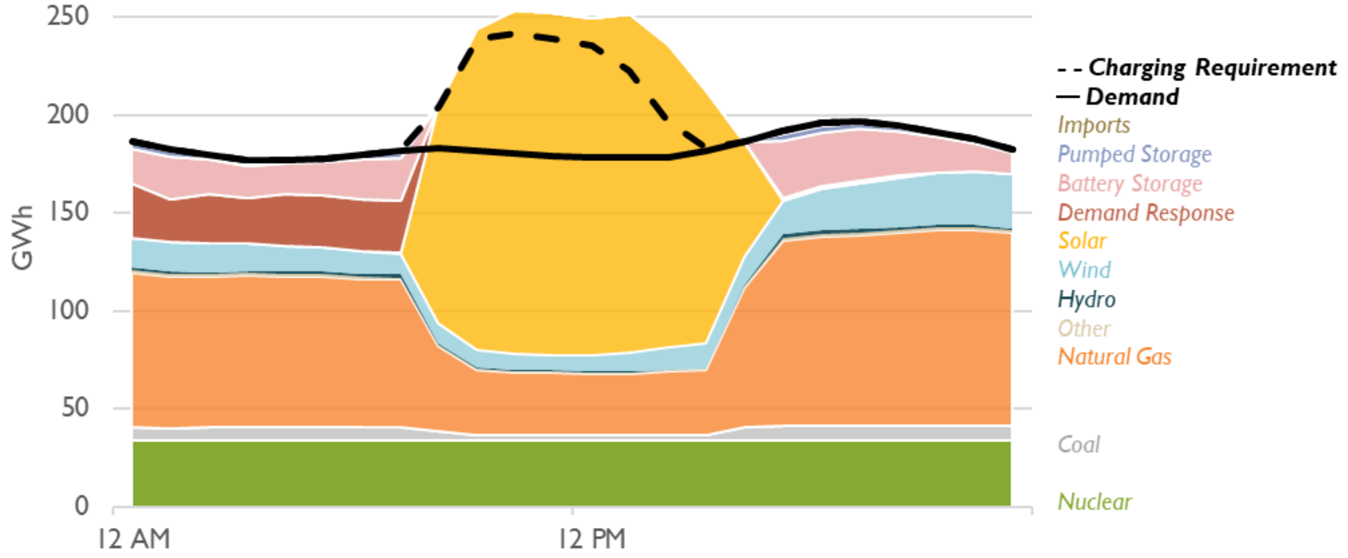


Figure 12. Advanced Policy scenario resources and load on January 7, 2035



4. COSTS AND EMISSIONS RESULTS

In addition to providing reliability benefits, AETs offer a future pathway for PJM that is less expensive and produces fewer greenhouse gas emissions.

4.1. Increased Deployment of AETs Reduces Costs Relative to the Status Quo Scenario

In addition to providing a much more reliable grid, the Advanced Policy scenario is less expensive than the Status Quo scenario in every year, reducing both energy costs and capacity costs (see Figure 13). From 2025 to 2035, the additional AETs reduce cumulative total system costs by $178 billion, or 20 percent, relative to the Status Quo scenario.[61] Due to the limitations on AET availability, the Status Quo scenario leads to greater reliance on inefficient thermal resources in the region that are further up the energy market supply curve, driving up energy prices. In contrast, the Advanced Policy scenario yields greater quantities of zero-marginal-cost renewable energy resources (such as solar and wind), which depress energy prices. In the Status Quo scenario, lower levels of available firm capacity cause capacity prices to remain high, whereas in the Advanced Policy scenario, AETs with relatively high firm capacity accreditation (such as battery storage, DR, and wind) drive down capacity prices in the second half of the model period.

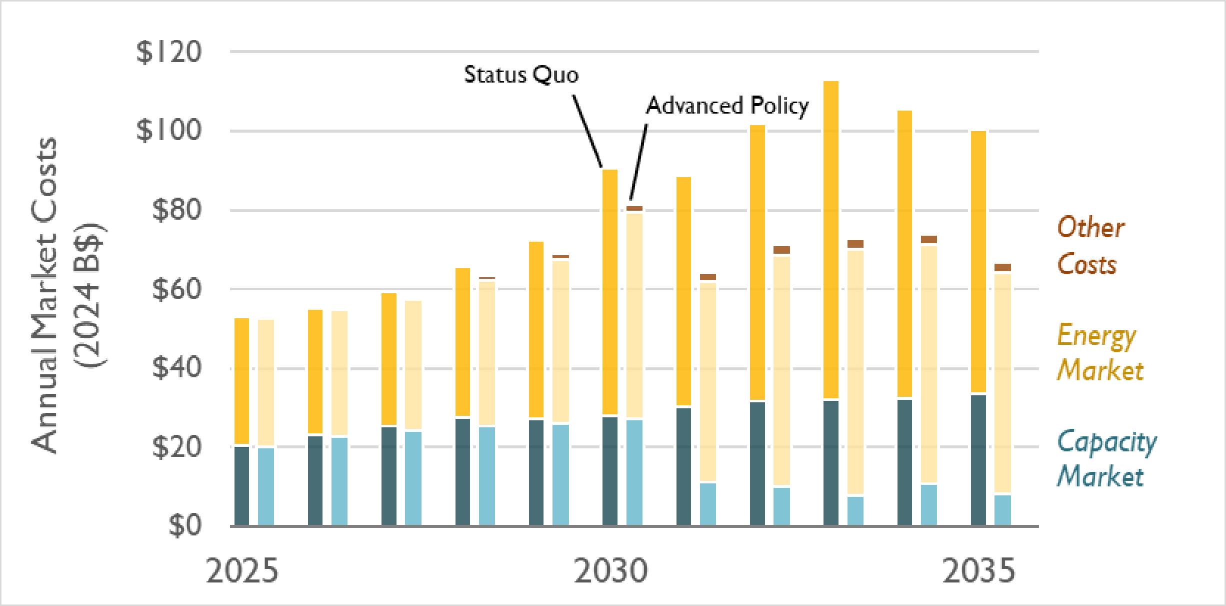
The Advanced Policy scenario also includes “other costs,” including costs associated with advanced transmission technologies and participant costs related to energy efficiency. However, these are relatively small compared with the energy market and capacity market.[62] Further costs, such as non-market payments to demand response resources, for example, are not included. While our analysis does not calculate detailed electric rate and bill outputs for utility customers, our findings of lower systemwide costs indicate that the savings in the Advanced Policy scenario would produce lower bills for ratepayers than in the Status Quo scenario.

---

[61] This figure is presented in real 2024 dollars.

62 Participant costs refer to the costs that the participant must pay to do the energy efficiency measure. For example, imagine a standard fridge costs $500, and an efficient one, $600. If the utility offers at $50 rebate, the participant might be willing to pay the remaining $50 to buy the efficient device. The remaining $50 is the participant cost.

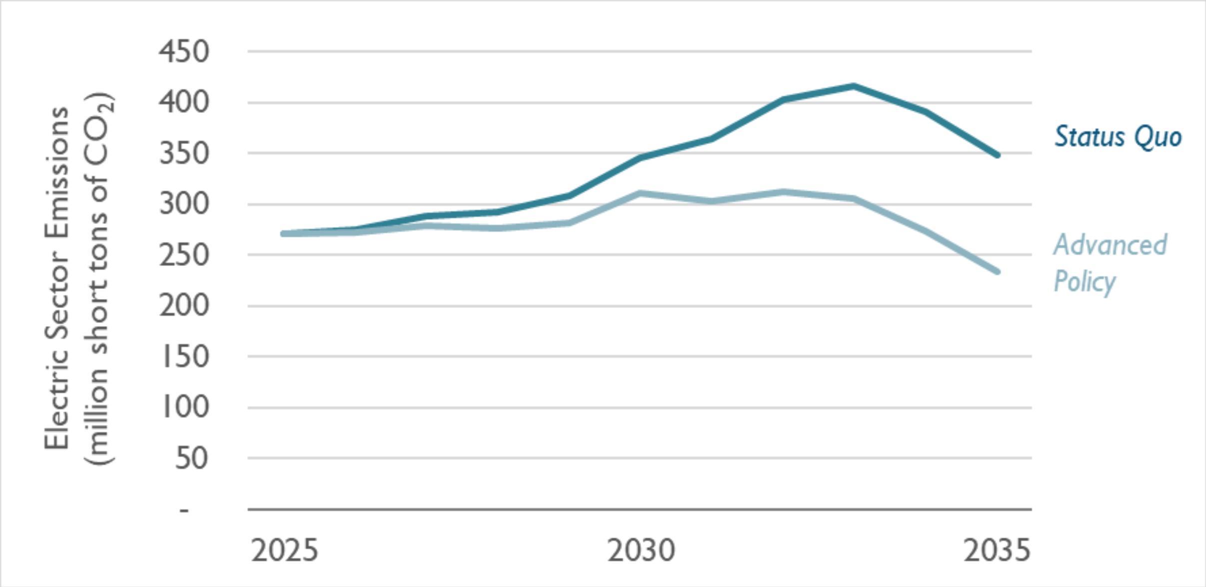
Figure 13. Comparison of market costs



4.2. Deploying More AETs Also Lowers CO_2 Emissions

The Advanced Policy scenario results in lower carbon dioxide (CO_2) emissions in every year because it yields lower demand (due to increased energy efficiency), more zero-emitting generation, and less gas and coal generation. Cumulative emissions from 2025 to 2035 are about 584 million short tons (16 percent) lower in the Advanced Policy scenario, relative to the Status Quo scenario. By 2035, annual electric sector emissions are 33 percent lower in the Advanced Policy scenario (see Figure 14). While this was not the focus of the analysis, it can be considered an added benefit.

Figure 14. Annual electric sector CO_2 emissions



5. DISCUSSION AND CONCLUSION

Our analysis illustrates the potential reliability and cost benefits of deploying higher levels of AETs in PJM. Our study demonstrates the ability of these technologies to resolve near-term resource adequacy concerns caused by rapid data center-driven load growth and associated supply–demand imbalances, as well as how these technologies can continue to provide low-cost, reliable electricity service at higher penetration levels in the longer term.

The only difference between the inputs to the Status Quo and Advanced Policy scenarios is higher "build limits" that allow the model to select higher levels of AETs in the Advanced Policy scenario. As discussed above, these build limits reflect the l barriers to deployment that AETs currently face. Policy and regulatory action is needed to achieve the levels we modeled in the Advanced Policy case. Transparent, robust, data-driven consideration of AETs in electricity system planning will be important to ensure that the benefits of AETs are appropriately represented when they are being compared with alternative resources (such as new gas plants). A narrow focus on prioritizing resources based on their individual ELCC values fails to capture the system-wide benefits of a diverse set of complementary resources.

5.1. Enabling Policies to Accelerate Deployment of AETs

Targeted policies could accelerate the deployment of AETs, unlocking the reliability and cost savings benefits modeled in this analysis. These policies could include:

- **Interconnection reform:** Continued focus on reforming PJM's interconnection queue will unlock the gigawatts of large-scale advanced energy technologies that are currently waiting for interconnection service agreements. Increased transparency and efforts to reduce delays that occur after an interconnection agreement is signed would also speed the process of bringing new resources online. States can urge PJM to make sensible reforms to this process.

- **Improving local permitting and siting processes:** Streamlining local siting and permitting processes for large-scale advanced energy projects will reduce timelines and soft costs associated with building these new resources. As of June 2025, PJM announced there were 46 GW of projects that had interconnection service agreements, but had not been built yet.[63] These local siting and permitting process issues would likely need to be resolved at the state, county, or municipal level.

- **Better incorporating ATTs into transmission planning and interconnection studies:** Transmission owners may be disincentivized to invest in ATTs, since they are often lower-cost than alternative investments, meaning transmission owners would earn a smaller rate of return

---

[63] PJM. June 2025. "Generation Interconnection Factsheet." Available at: https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/interconnection-reform-progress-fact-sheet.pdf

on these investments. State legislators and public utility commissioners have many options to address this issue, including requiring utilities to conduct benefit–cost analyses of ATTs and requiring utilities to justify their decisions in cases where they do not select ATTs.[64] PJM and local utilities may need to modernize their transmission planning process to best optimize ATT investments.[65]

- **Improving energy efficiency goals and program design:** In many states, cutting energy efficiency program funding is being considered as a mechanism to reduce utility bills in the short term, despite consistent findings that energy efficiency is a cost-effective investment. States could instead consider increasing utility energy efficiency requirements as a lever for addressing resource adequacy. Improving cost–benefit screening, improving rate and bill analysis, and improving program design to ensure equitable program access and participation are levers for accelerating cost-effective energy efficiency programs.
- **Providing a clear path to market participation for emerging load flexibility solution providers:** Falling DER costs and the electrification of buildings and vehicles are leading to the deployment of more flexible resources behind the meter each year. In addition, some large load customers, such as data centers, may be able to provide load flexibility services either by ramping down energy usage during peak periods or by using DERs such as battery storage. These trends provide new opportunities for load flexibility aggregators to provide demand response (sometimes called virtual power plants). However, emerging load flexibility solutions require supportive market structures that can adequately value the services they can provide. States can develop their own programs to incentivize these resources, and can encourage PJM to develop a more robust market for load flexibility.
- **Successfully enabling DERs to participate in PJM wholesale markets:** FERC Order 2222 requires regional transmission organizations (such as PJM) to allow DERs to provide all wholesale market services that they are technically capable of providing. PJM is currently working on implementing this requirement, aiming to enable DER aggregators to bid into the capacity market auction starting in May 2026 (targeting the 2028/2029 forward auction) and the energy market by February 2028.[66] Successful implementation will open up a new revenue opportunity for DER aggregators.

---

[64] RMI. October 2025. "How State Regulators Can Utilize the Latest Legislative Trend to Make Electricity More Affordable and Reliable." Available at: https://rmi.org/how-state-regulators-can-utilize-the-latest-legislative-trend-to-make-electricity-more-affordable-and-reliable

[65] Quanta Technology. July 2025. "Advanced Transmission Technologies Planning Guide." Available at: https://quanta-technology.com/report/report-on-advanced-transmission-technologies/

[66] PJM. 2025. "DER Aggregator Participation Model: Overview." Available at: https://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/disrs/postings/ferc-order-no-2222-overview.pdf

5.2. Risks of Overreliance on Traditional Fossil Resources

The worse reliability performance of the Status Quo scenario compared with the Advanced Policy Scenario also highlights the risks of overreliance on traditional fossil resources. Gas turbine supply chain constraints and long construction lead times limit the quantity of new gas capacity that can come online quickly, and the current high demand for turbines has driven up costs considerably.[67] In addition, the operational constraints of coal and gas, including slow ramp times and high winter forced outage rates, can limit their contributions to reliability. Furthermore, although this study did not focus on fuel price risk, increased reliance on gas plants would increase ratepayer exposure to volatile energy prices associated with fluctuations in natural gas fuel costs. In contrast, advanced energy technologies that are not reliant on fuel inputs can insulate customers from these price shocks.

Policies that disproportionately favor the deployment of natural gas resources—such PJM's RRI and more recent Expedited Interconnection Track proposal—risk missing out on the opportunity to improve reliability using a more varied suite of advanced resources and tools. This study indicates that greater advanced energy deployment would succeed at cost-effectively reducing—and in some cases preventing—outages across the PJM region in 2030 and 2035.

---

[67] For more information, see: *The New Reality of Power Generation: An Analysis of Increasing Gas Turbine Costs in the U.S.* GridLab. September 2025. Available at https://gridlab.org/portfolio-item/gas-tubine-cost-report/.