Review of 2026 RTEP Assumptions

Transmission Expansion Advisory Committee

Wenzheng Qiu, Emmanuele Bobbio
PJM Planning

April 7, 2026

- 2026 RTEP
  - TPL-001-5
  - PJM Planning Criteria
  - TO form 715 Planning Criteria
- Modeling
  - MOD-032 (GOs and TOs)
  - http://pjm.com/planning/rtep-development/powerflow-cases/mod-032.aspx
  - Siemens PSS®MOD - Model On Demand (TOs)
  - PJM.com Planning Center Online Tool (Gen Model) – GOs

Expected Timeline

- **November 2025**: Establish 2026 RTEP base case modeling assumptions

- **November 2025 to March 2026**: Build base cases and perform initial case review. During this period;
  - New modeling and other basic assumption changes may be considered if PJM determines they may have a significant impact on the near-term RTEP baseline studies. PJM will notify TEAC and provide an update summarizing changes as needed.
  - Corrections to the analytical files will be accepted.

- **March to June 2026**: Perform RTEP baseline studies.
  - Adjustments to the analytical files will only be implemented if they have a widespread impact or will likely impact one or more identified violations.

Expected Timeline

- **July 2026** (**targeting beginning of July 2026**)
  - Open competitive proposal window
  - Post modeling assumptions changes and corrections and begin mid-year retool of 2026 RTEP baseline analysis if required
    - Accounts for major new modeling assumption changes and corrections not previously considered.
    - Basic assumptions such as planning criteria and ratings methodology that changed after March will not be considered until the 2027 RTEP.
- **August/September 2026**
  - Close competitive proposal window
  - Finalize mid-year retool if required
- **September to November 2026**: Evaluate proposals
- **October 2026 to February 2027**: Review (TEAC) and Approve proposals (PJM Board)

- Load Flow Modeling
  - Power flow models for outside world load, capacity, and topology will be based on the following 2025 Series MMWG power flow cases
    - 2030 SUM MMWG outside world for 2025 Series 2031 SUM RTEP, 2029 SUM RTEP
    - 2030 LL MMWG outside world for 2025 Series 2031 LL RTEP
    - 2030 WIN MMWG outside world for 2025 Series 2031 WIN RTEP, 2029 WIN RTEP
    - 2027 SUM MMWG outside world for 2025 Series 2027 SUM RTEP
  - PJM to work with neighbors to identify any updates to topology/corrections
  - PJM topology for all cases sourced from Model On Demand
    - Include all PJM Board approved upgrades through the Q1 2026 PJM Board of Manager approvals.
    - Include all Supplemental Projects included in 2025 Local Plan
    - In order to avoid development of redundant reinforcements, all reinforcements from earlier RTEPs will be modeled based on required in service date.

- Firm Commitments
  - Long term firm transmission service consistent with those coordinated between PJM and other Planning Coordinators during the 2025 Series MMWG development

- Outage Rates
  - Generation outage rates will be based on the most recent Reserve Requirement Study (RRS) performed by PJM
  - Generation outage rates for future PJM units will be estimated based on class average rates

- At a minimum, all PJM bulk electric system facilities, all tie lines to neighboring systems and all lower voltage facilities operated by PJM will be monitored.
- At a minimum, contingency analysis will include all bulk electric system facilities, all tie lines to neighboring systems and all lower voltage facilities operated by PJM.
- Thermal and voltage limits will be consistent with those used in operations and those specified in the Form 715 planning criteria. In all cases, the more conservative value will be used.

2026 RTEP Load Modeling

- Summer Peak Load
  - Summer Peak Load will be modeled consistent with the 2026 PJM Load Forecast Report (or most updated load forecast)

- Winter Peak Load
  - Winter Peak Load will be modeled consistent with the 2026 PJM Load Forecast Report

- Light Load
  - The Light Load Reliability Criteria case will be modeled consistent with the procedure defined in M14B

- Demand Side Load Management, where applicable, will be modeled consistent with the 2026 Load Forecast Report
  - Used in LDA under study in load deliverability analysis

2026 RTEP Generation Assumptions

- All existing generation expected to be in service for the year being studied will be modeled.
- Future generation with signed Interconnection Service Agreement (ISA) or Generation Interconnection Agreement (GIA), or that cleared in the 2025/26 BRA, will be modeled along with any associated network upgrades.
  - Generation with a signed ISA/GIA will contribute to and be allowed to back-off problems.
- Off-Shore Wind
  - NJ and Delmarva offshore wind generation will not be included in this year RTEP base cases (2031 RTEP base cases and 2034 RTEP base cases).
- If needed, additional generation (pre-GIA stage or with a suspended status) may be modeled consistent with the procedures noted in Manual 14B.
- Energy storage including BESS will be modeled and dispatched in base case as needed.

2026 RTEP Generation Assumptions

- 5 Year (2031) Analysis
  - Balance load with: Existing generation, GIA/ISA generation including CVOW, Suspended ISA generation, and RRI projects (part of TC2).
  - No consideration of a “targeted LOLE”

- 8 Year (2034) Analysis
  - Refer to the “Capacity Expansion for RTEP” section in this slides

Battery Dispatch Level in Base Cases

The Batteries are proposed to be dispatched in RTEP base cases using the following rules.

- Summer: Min($\frac{ENC \times Storage\ Duration}{4}$, ENC*)×(1-PJM Avg EEFORd)
- Winter: Min($\frac{ENC \times Storage\ Duration}{8}$, ENC)×(1-PJM Avg EEFORd)
- Light Load: Charging at ENC×(1-PJM Avg EEFORd)

* **ENC: Effective Nameplate Capacity**

Generation with Deactivation Notification

- Generation that has officially notified PJM of deactivation will be modeled offline in RTEP base cases for all study years after the intended deactivation date
- RTEP baseline upgrades associated with generation deactivations will be modeled
- Retired units Capacity Interconnection Rights are maintained in RTEP base cases for 1 year after deactivation at which point they will be removed unless claimed by a queued interconnection project

PSEG/NY Interface

- PJM/NYISO Interface
  - B & C cables will be modeled out of service consistent with 2025 RTEP
- Linden VFT
  - Modeled at 330 MW (Towards NY)
- HTP (HVDC link)
  - Modeled at 0 MW Schedule

Capacity Factors For Wind & Solar Base Case Dispatch As Percent of Maximum Facility Output

MAAC	Summer CF*	Winter CF	Light Load CF
Solar Fixed	44%	5%	51%
Solar Tracking	61%	5%	53%
Onshore Wind	15%	38%	28%
Offshore Wind	36%	55%	47%

PJM West	Summer CF*	Winter CF	Light Load CF
Solar Fixed	62%	5%	60%
Solar Tracking	64%	5%	53%
Onshore Wind	18%	42%	34%
Offshore Wind	N/A	N/A	N/A

DOM	Summer CF*	Winter CF	Light Load CF
Solar Fixed	49%	5%	57%
Solar Tracking	62%	5%	58%
Onshore Wind	18%	36%	29%
Offshore Wind	31%	57%	46%

*** Use lower of CIR or Capacity Factor (CF)**

Wind & Solar Harmer Dispatch
As Percent of Maximum Facility Output

MAAC	Summer**	Winter	Light Load
Solar Fixed ($P_{80\%}$)	63%	*	*
Solar Tracking ($P_{80\%}$)	80%	*	*
Onshore Wind ($P_{90\%}$)	37%	71%	63%
Offshore Wind ($P_{80\%}$)	72%	93%	88%

PJM West	Summer**	Winter	Light Load
Solar Fixed ($P_{80\%}$)	80%	*	*
Solar Tracking ($P_{80\%}$)	79%	*	*
Onshore Wind ($P_{90\%}$)	50%	83%	79%
Offshore Wind ($P_{80\%}$)	N/A	N/A	N/A

DOM	Summer**	Winter	Light Load
Solar Fixed ($P_{80\%}$)	66%	*	*
Solar Tracking ($P_{80\%}$)	78%	*	*
Onshore Wind ($P_{90\%}$)	41%	72%	68%
Offshore Wind ($P_{80\%}$)	68%	98%	94%

*** Not applicable**

****CIR level will be used for summer, single contingency testing**

Wind & Solar Helper Dispatch
As Percent of Maximum Facility Output

MAAC	Summer P20%	Winter P20%	Light Load (P20%)
Solar Fixed	27%	0%	23%
Solar Tracking	42%	0%	26%
Onshore Wind	2%	14%	5%
Offshore Wind	4%	15%	7%

PJM West	Summer P20%	Winter P20%	Light Load (P20%)
Solar Fixed	44%	0%	33%
Solar Tracking	49%	0%	28%
Onshore Wind	2%	12%	6%
Offshore Wind	N/A	N/A	N/A

DOM	Summer P20%	Winter P20%	Light Load (P20%)
Solar Fixed	32%	0%	33%
Solar Tracking	46%	0%	34%
Onshore Wind	4%	14%	6%
Offshore Wind	1%	13%	5%

Generator Deliverability: Generic EEFORds

- Generic EEFORd values developed for 2031 RTEP base case 5.18%

- Capacity weighted by fuel type
  - Each unit within a given generator class is assigned the average EEFORd for that class

Gen Class	Avg EEFORd
Diesel	13.57%
Fossil Steam	12.11%
Hydro	8.15%
Combustion Turbine	7.52%
Pumped Storage	5.57%
Combined Cycle	4.46%
Nuclear	1.42%
Wind	0.00%
Solar	0.00%
Battery	5.00%

24 Month RTEP

- As part of the 24-month RTEP cycle, a year-8 (2034) base case will be developed and evaluated part of the 2026 RTEP

- The purpose of the study is to identify and develop longer-term needs and right size near-term upgrades accordingly

FERC 1000 Process

- Per the PJM Operating Agreement, a proposal window will be conducted for all reliability needs that are not designated as Immediate Need reliability upgrades or are otherwise ineligible to go through the window process.

- FERC 1000 implementation will follow;
  - Advance notice and posting of potential violations
  - Advance notice of window openings
  - Window administration

Locational Deliverability Areas (LDAs)

- Includes the existing 27 LDAs
- Total of 27 LDAs
  - All 27 to be evaluated as part of the 2026 RTEP

LDA	Description
EMAAC	Global area - PJM 500, JCPL, PECO, PSEG, AE, DPL, RECO
SWMAAC	Global area - BGE and PEPCO
MAAC	Global area - PJM 500, Penelec, Meted, JCPL, PPL, PECO, PSEG, BGE, Pepco, AE, DPL, UGI, RECO
PPL	PPL & UGI
PJM WEST	APS, AEP, Dayton, DUQ, Comed, ATSI, DEO&K, EKPC, Cleveland, OVEC
WMAAC	PJM 500, Penelec, Meted, PPL, UGI
PENELEC	Pennsylvania Electric
METED	Metropolitan Edison
JCPL	Jersey Central Power and Light
PECO	PECO
PSEG	Public Service Electric and Gas
BGE	Baltimore Gas and Electric
PEPCO	Potomac Electric Power Company
AE	Atlantic City Electric
DPL	Delmarva Power and Light
DPLSOUTH	Southern Portion of DPL
PSNORTH	Northern Portion of PSEG
VAP	Dominion Virginia Power
APS	Allegheny Power
AEP	American Electric Power
DAYTON	Dayton Power and Light
DLCO	Duquesne Light Company
Comed	Commonwealth Edison
ATSI	American Transmission Systems, Incorporated
DEO&K	Duke Energy Ohio and Kentucky
EKPC	Eastern Kentucky Power Cooperative
Cleveland	Cleveland Area

- PJM will account for the PJM States input towards the development of the 2026 RTEP Scenarios.

Capacity Expansion for the 2026 RTEP 8-Year Cases

Outline

- Background:
  - Need for using capacity expansion
  - Expected capacity deficiency in the 2026 RTEP 8-year cases
- Capacity expansion assumptions

Background

- Planning models are used to assess regional transmission needs to maintain reliability, market efficiency, and operational performance, and consider federal and state Public Policy Requirements
- To meet forecasted load demand, PJM develops a load forecast through its open and transparent process
- The load forecast is integrated into the model for the year under study together with planned transmission enhancements and anticipated future generation (and retirements)
- For the model to be solvable and credible, it must include sufficient generation to cover forecasted load, plus losses, firm transfers and with some breathing room to represent a reasonable future operating state of the system (reserves)
- Capacity expansion modeling is an industry best practice to assist with generation assumptions, capturing economic and policy factors among other things
- Under such approach, the identified constraints (and solutions) will focus more on addressing regional, bulk transfer needs rather than local constraints that may arise due to non-queued generation modeled in the case (which will be covered as part of the interconnection needs as this generation comes to fruition).
- PJM has been using capacity expansion modeling, indirectly, in earlier RTEP cycles to model expected regional flows for assessing the robustness of regional solutions

Need for Capacity Expansion Modeling in the 2026 RTEP for 2034 model-year (8-year cases)

- For 2034 planning models, PJM is forecasting 218,339MW of peak load in the Summer and 204,549 in the Winter
- PJM cannot solve the 2034 reliability cases due to insufficient generation to meet system demand (existing generation + signed GIA dispatchable capacity is less than ~193GW in the Summer and 186GW in the Winter)
- When all queued projects without a signed interconnection agreement (TC2) are included, the total dispatchable capacity is less than 215GW in the Summer and 201GW in the Winter
- PJM intends to use industry best practices, i.e. capacity expansion modeling to supplement the generation assumptions in the planning models (starting with the 2034 RTEP Planning Suite)
  - Industry examples: Dominion, AEP, CAISO, MISO, ISO-NE, NYISO, EIA, S&P, EPRI, NRL, etc.
  - At PJM:
    - Stakeholder education during the LTRTP Workshop (07/21/2023, 08/22/2023, 09/21/2023, 11/09/2023, 12/15/2023)
    - Workshop Policy Study and PJM/MISO Interregional Transfer Capability Study (10/1/2024 TEAC, 12/10/2024 TEAC, IPSAC 06/25/2025)
    - Informational Base Scenario for FO1920 special TEACs (04/10/2025, 05/09/2025, 07/18/2025, 09/05/2025, 10/10/2025)
    - PJM Whitepaper on Order 1920 Compliance Approach (9/5/2025)
    - 2025 RTEP Scenario 5 (12/08/2025 TEAC)
- PJM plans to discuss capacity expansion in more detail as part of Order 1920 manual revisions later this year

Capacity Expansion Assumptions (2026 RTEP, 8-year cases)

- Scenario A (Base 8-year cases):
  - Include all remaining projects in the generation interconnection queue (except for bullet 3) before considering additional generation
  - Model RPS policies and battery storage targets
  - Do not model offshore wind nor new gas in NJ, MD, DE, IL, and eastern PA unless the project has ISA/GIA or existing SAA agreement
  - Do not model deactivations beyond those already announced
- Scenario B (sensitivity)
  - Do not include the remaining projects in the generation interconnection queue unless economic/consistent with state and federal policies
  - Model RPS policies, battery and offshore wind targets and allow new gas in NJ, MD, DE, IL, in eastern PA
  - Model policy-driven deactivations
- The goal is to capture the impacts of each scenario assumptions to inform project selection and sizing
- Planning assumptions will evolve over time and PJM will adjust its plans as the assumptions materialize or change

Other Assumptions

- PJM will be utilizing Energy Exemplar's Eastern Interconnection Dataset (EEEI) with following changes
- Expansion horizon: 2032-2046
  - RTEP 2031 is the start for the expansion
- 2026 PJM Load Forecast
- Expansion candidates solar, onshore wind, offshore wind, hybrid, CC, CT, 4h battery,10h battery
- Henry hub gas price from PJM Market Efficiency
- Discount rate: United States 20-year treasury rate
- CAPEX, FOM, VOM, heat rate, and other financial assumptions from Quadrennial Review, EEEI, NLR/NETL (in this order)
- Build up to 2x of existing generation + queue by 2034, 3x by 2045 (for VA 3x,10x respectively) and based on land availability for solar and onshore using the National Laboratory of the Rockies (NLR) Limiting Access scenario
- Model ELCC and 1-in-10 resource adequacy target

Next Steps

- Stakeholders can provide feedback on the capacity expansion assumptions for the 8-year reliability cases (including the assumptions detailed in Appendix II) either during today's TEAC meeting, April 7, or in writing prior to Wednesday, April 22
- PJM will consider the stakeholder feedback on these assumptions and target finalizing the assumptions at the May 8 TEAC
- PJM intends to further discuss PJM's capacity expansion approach for Order 1000 planning as opposed to Order 1920 planning within the stakeholder process for Order 1920 manual revisions later in 2026

Appendix I

Additional Deactivation Units for RTEP 2026

Unit	Capacity(MW)	Trans Zone	State
Ocean County LF	9.1	JCPL	NJ
Forked River Unit 2	31	JCPL	NJ
Forked River Unit 1	34	JCPL	NJ
Cumberland CT 1	79	ACE	NJ
Sherman Avenue CT1	79	ACE	NJ
Cooper 1	116	EKPC	KY
Kincaid 1	556	ComEd	IL
Kincaid 2	556	ComEd	IL
Beech Ridge	32	APS	WV

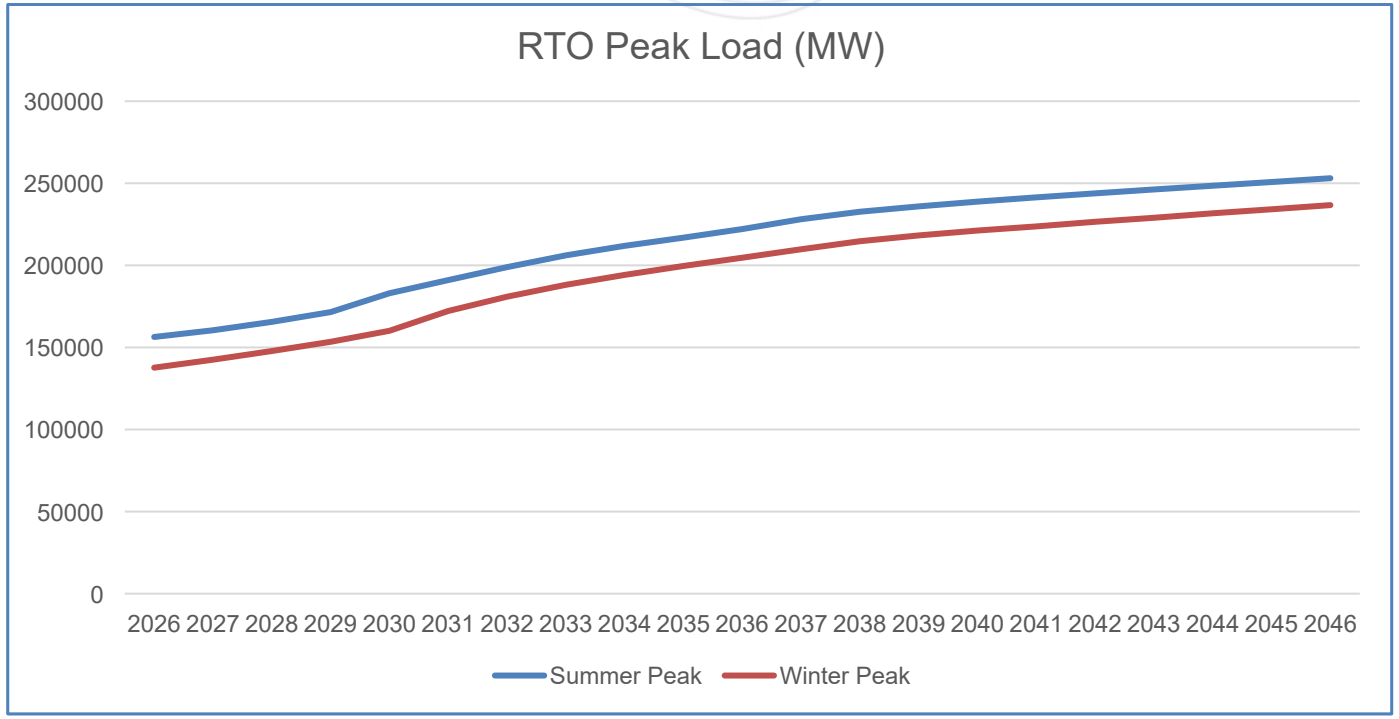
Appendix II

Assumptions

- Load assumptions
- Generation and storage technologies
- Fixed and Variable costs components
  - Fixed: Capital, fixed O&M, geographic adjustments coefficients
  - Variable: Heat rates, fuel costs, variable O&M
- Financial assumptions (fixed charge rate and discount rate)
- Renewable capacity factors
- Policy assumptions (new generation and deactivations)
- Resource adequacy
- Starting resource mix
- Build limits for capacity expansion (Generation Interconnection data and siting opportunities)

Load Assumptions

- PJM's 2026 Demand forecast



Generation and storage technologies

- Solar PV
- Onshore Wind
- Offshore Wind
- Battery Energy Storage (4-hour and 10-hour)
- Hybrid (Solar + Battery in 2:1 configuration)
- Combustion Turbine
- Combined Cycle

Fixed Costs, Variable Costs, and Financial Assumptions

- Fixed Costs, Variable Costs, and Financial assumptions based on available resources in the following order:
  - 2025 PJM Quadrennial Review
  - Energy Exemplar Eastern Interconnection data
  - NRL (Annual Technology Baseline) and NETL (Cost and Performance Baseline studies)

Fixed Costs

	Overnight Capital Cost (2028$/kW)	*FOM (2028$/kW-year)*
Combined Cycle		
EMAAC	1517	41.0
SWMAAC	1411	61.0
Rest of RTO	1419	57.0
WMAAC	1476	48.0
COMED	1649	38.0
Combustion Turbine		
EMAAC	1395	21.0
SWMAAC	1339	33.0
Rest of RTO	1361	25.0
WMAAC	1390	21.0
COMED	1495	21.0
BESS 4-hr		
EMAAC	1832	57.0
SWMAAC	1753	62.0
Rest of RTO	1750	55.0
WMAAC	1784	57.0
COMED	1980	59.0

Brattle 2025 CONE Report for PJM (Quadrennial Review)
https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2025/20250411-special/item-01-2-cone-report-final.pdf

Variable Costs

	VOM (2028$/MWh)	Heat Rate (Btu/kWh)
Combined Cycle		
EMAAC	2.6	6318
SWMAAC	2.6	6345
Rest of RTO	2.7	6303
WMAAC	2.7	6314
COMED	2.6	6294
Combustion Turbine		
EMAAC	1.1	9166
SWMAAC	1.1	9161
Rest of RTO	1.0	9141
WMAAC	1.1	9149
COMED	1.1	9133

Heat rate for combined cycle is without duct firing

Brattle 2025 CONE Report for PJM (Quadrennial Review)
https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2025/20250411-special/item-01-2-cone-report-final.pdf

Financial Assumptions

- Fixed charge rate: Annualization coefficient for overnight capital cost (referred to as “Capital Charge Rate” in Quadrennial Review)

	Combined Cycle	*Combustion Turbine*	*Battery*	
EMAAC	17.0%	16.0%	9.6%	
SWMAAC	16.9%	15.9%	9.6%	
Rest of RTO	16.9%	15.9%	9.6%	
WMAAC	16.9%	15.9%	9.6%	
COMED	18.8%	17.8%	9.6%	

Capital charge rate shown for Battery incorporates the 30% ITC

Brattle 2025 CONE Report for PJM (Quadrennial Review)

https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2025/20250411-special/item-01-2-cone-report-final.pdf

- Discount rate: United States 20-year treasury rate 4.9% as of March 31, 2026

Siting Constraints

- Many regulations governing the siting of wind and solar projects are established at the county or township level. Local zoning ordinances might affect the availability of land for wind and solar development.
- The most common zoning ordinances include setbacks from structures, roads, and property lines; sound restrictions; height limitations; and an increasing number of moratoriums or bans.
- PJM will use NREL's Limited Access siting scenario for wind and solar[1].
  - The Limited Access scenario uses environmental constraints, and national defense concerns, as well as conservative wind and solar setbacks based on local ordinances surveyed in Lopez et al.[2]

1 "Renewable Energy Technical Potential and Supply Curves for the Contiguous United States: 2024 Edition" https://www.nrel.gov/docs/fy25osti/91900.pdf
2 "Impact of siting ordinances on land availability for wind and solar development" https://www.nature.com/articles/s41560-023-01319-3

Geographic Adjustment Coefficients for Renewables

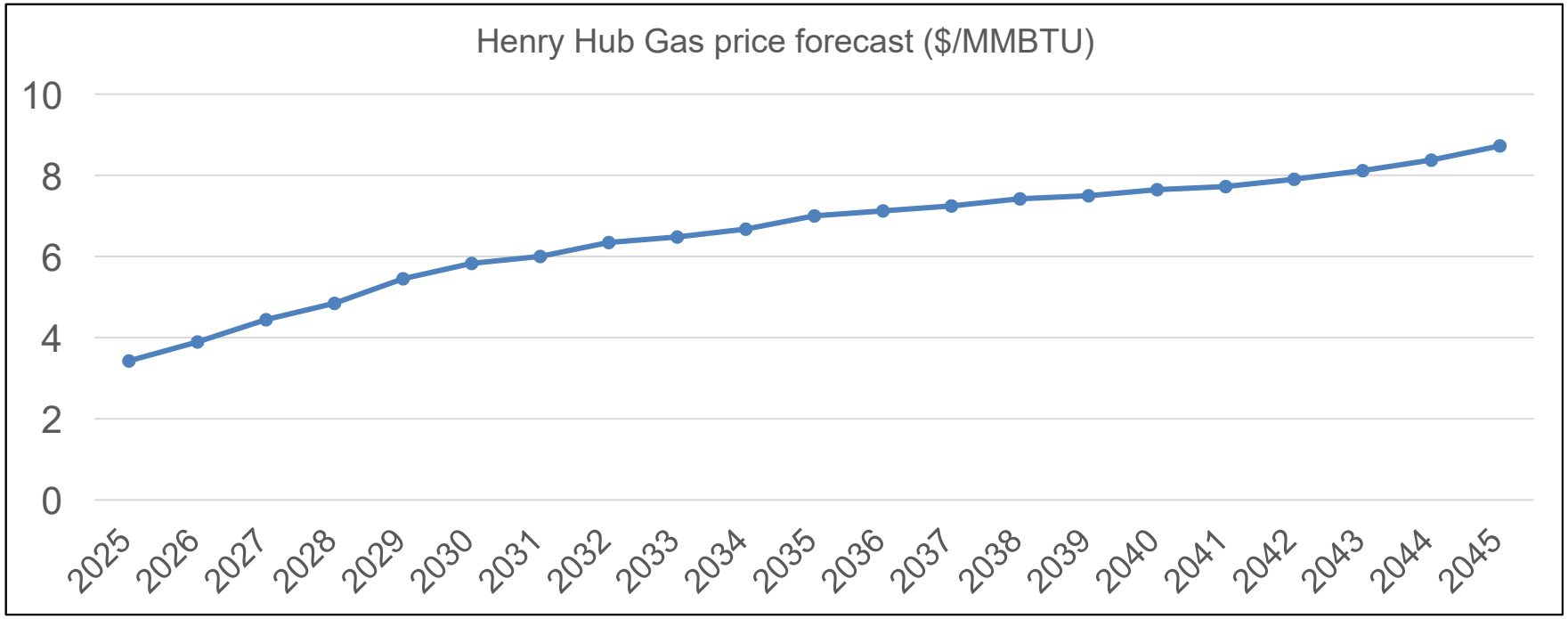
	Solar	Onshore	Offshore	Battery	Hybrid
Delaware	1.07	1.07	1.06	1.01	1.06
DC	1.01	1.03		1.01	1.01
Illinois	1.13	1.20	1.19	1.07	1.12
Indiana	1.00	1.02		1.02	1.00
Kentucky	1.00	1.01		1.02	1.01
Maryland	1.01	1.01	1.01	1.01	1.01
Michigan (Grand Rapids)	1.00	1.00	1.00	1.00	1.00
New Jersey	1.12	1.19	1.18	1.06	1.11
North Carolina	0.99	0.99	0.99	1.00	0.99
Ohio	0.99	0.98		0.99	0.99
Pennsylvania (Philadelphia)	1.11	1.18		1.06	1.10
Pennsylvania (Scranton)	1.02	1.03		1.01	1.02
Tennessee	1.00	1.02		1.04	1.01
Virginia (Alexandria)	1.00	1.02	1.02	1.01	1.01
Virginia (Roanoke)	0.99	0.98	0.98	1.00	0.99
West Virginia	1.01	1.00		1.00	1.01

Sargent & Lundy (2024) "Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies"

Gas Price

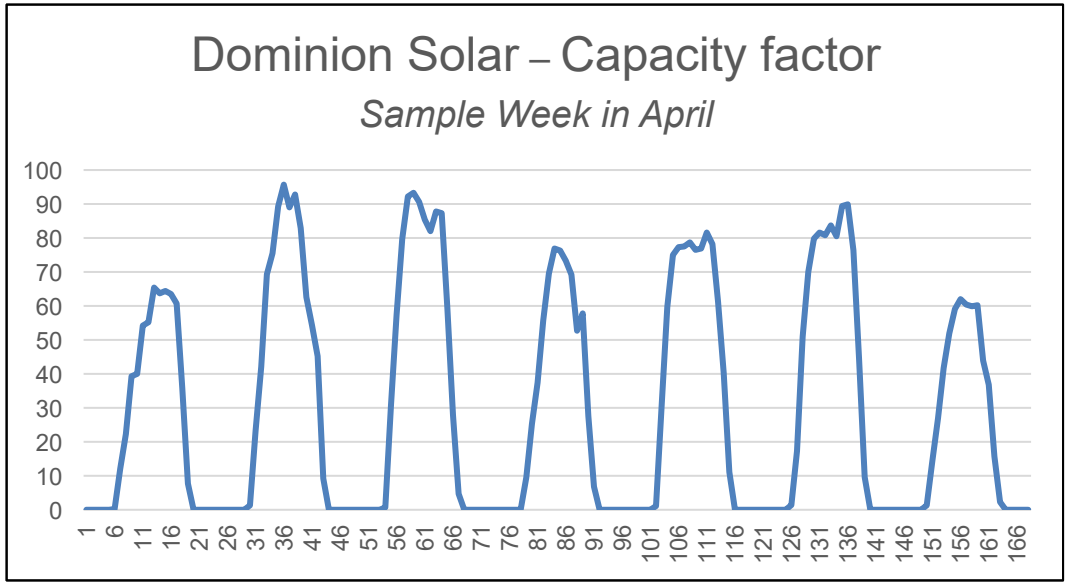
Latest forecast used by PJM's Market efficiency

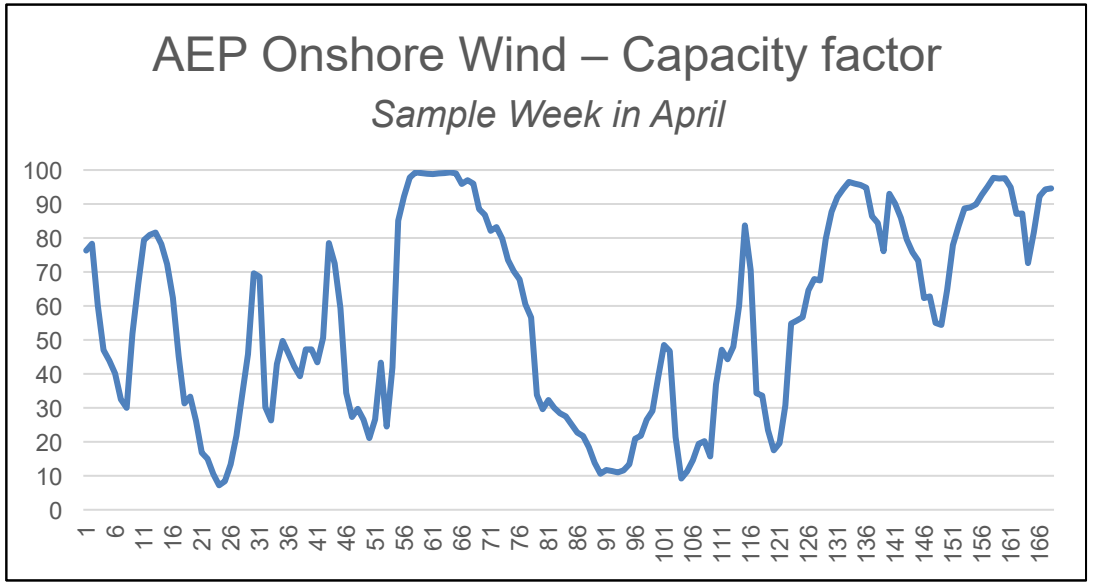
(Will be updated in May 2026 when Hitachi releases the updated forecast)



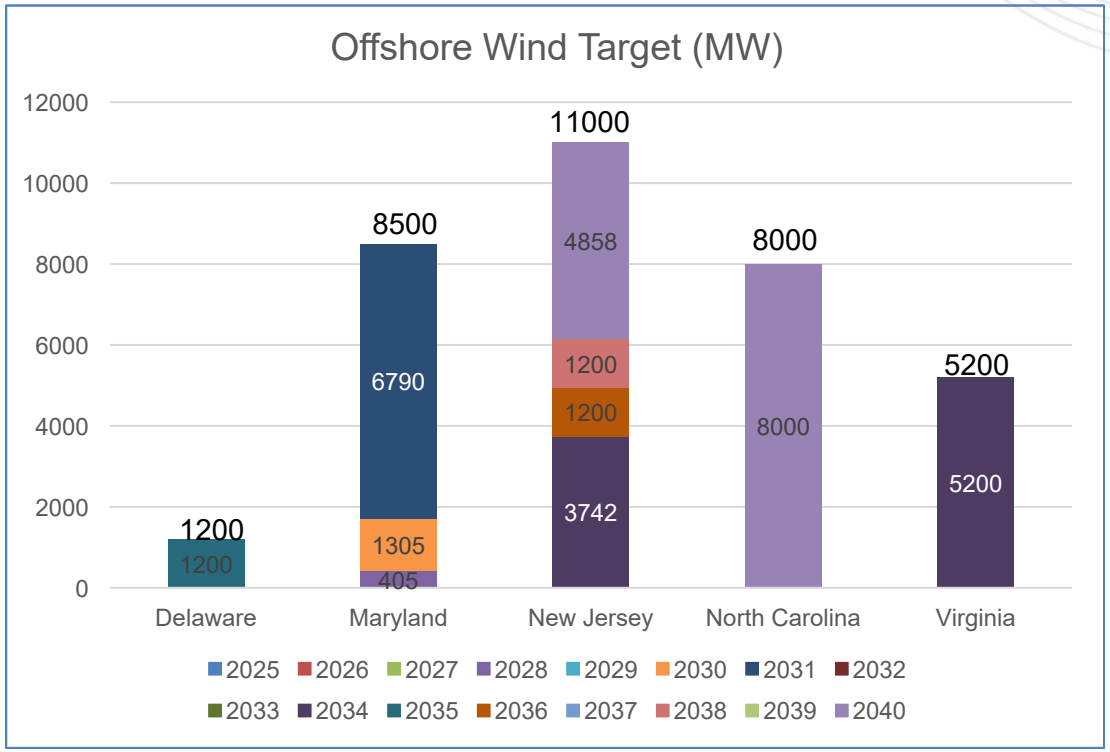
Renewable Capacity Factors

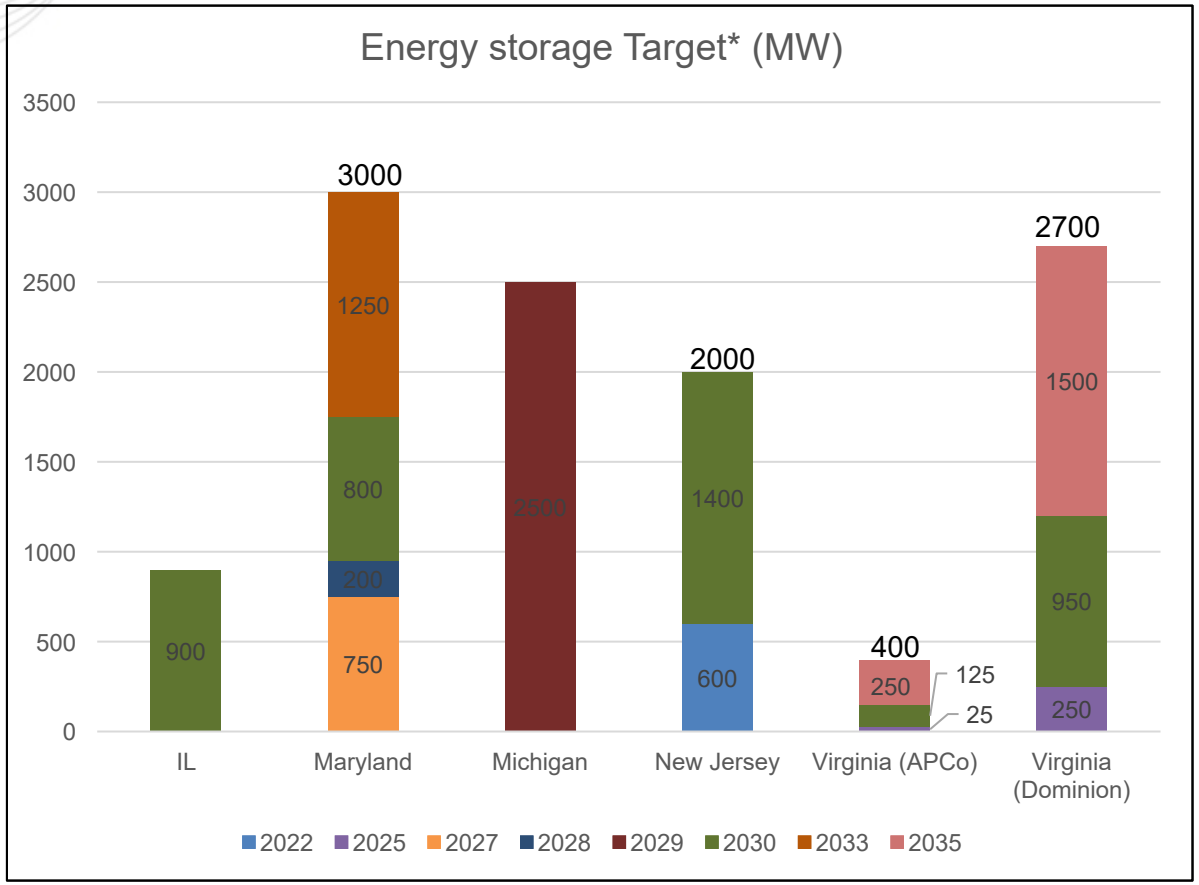
- Use Energy Exemplar's Eastern Interconnection hourly profiles for renewable capacity factors which are defined at the zonal level





Offshore and Energy Storage Targets



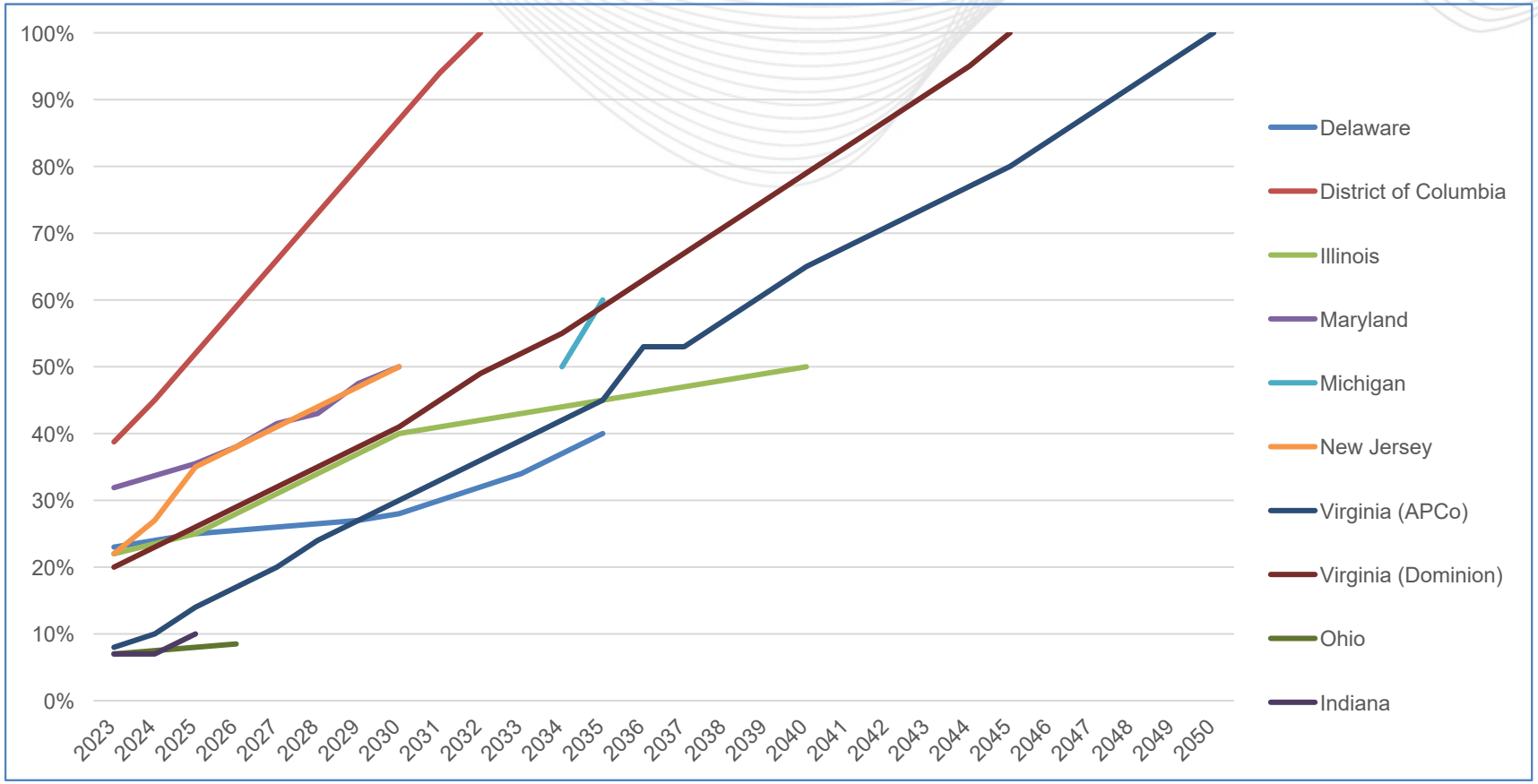


*IL has a target of 3000MW Energy Storage by 2030. 900MW of that target is assumed to be in PJM

North Carolina Offshore, Delaware Offshore and Michigan Energy Storage Targets

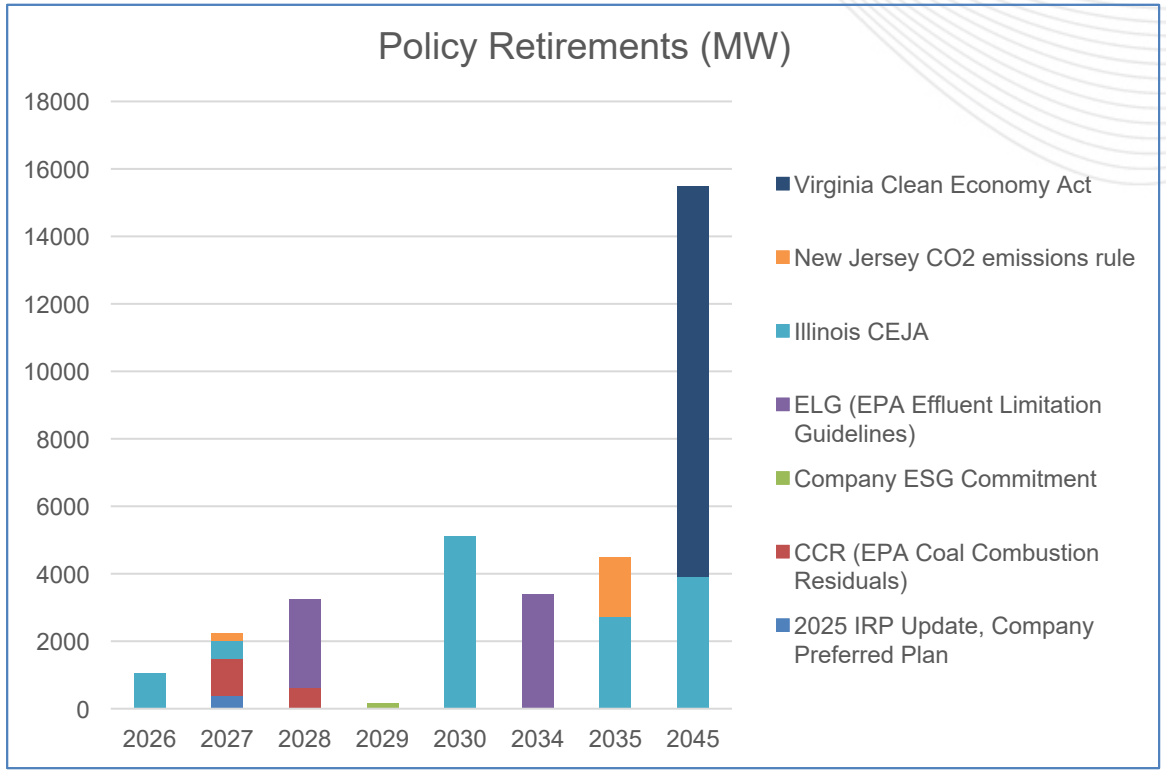
- PJM is not currently modeling North Carolina's offshore wind target as interconnecting into PJM or planning to model Delaware's Offshore wind target.
- Michigan's storage target for PJM is assumed to be 72.5 MW. PJM may plan for more energy storage as informed by the queue.

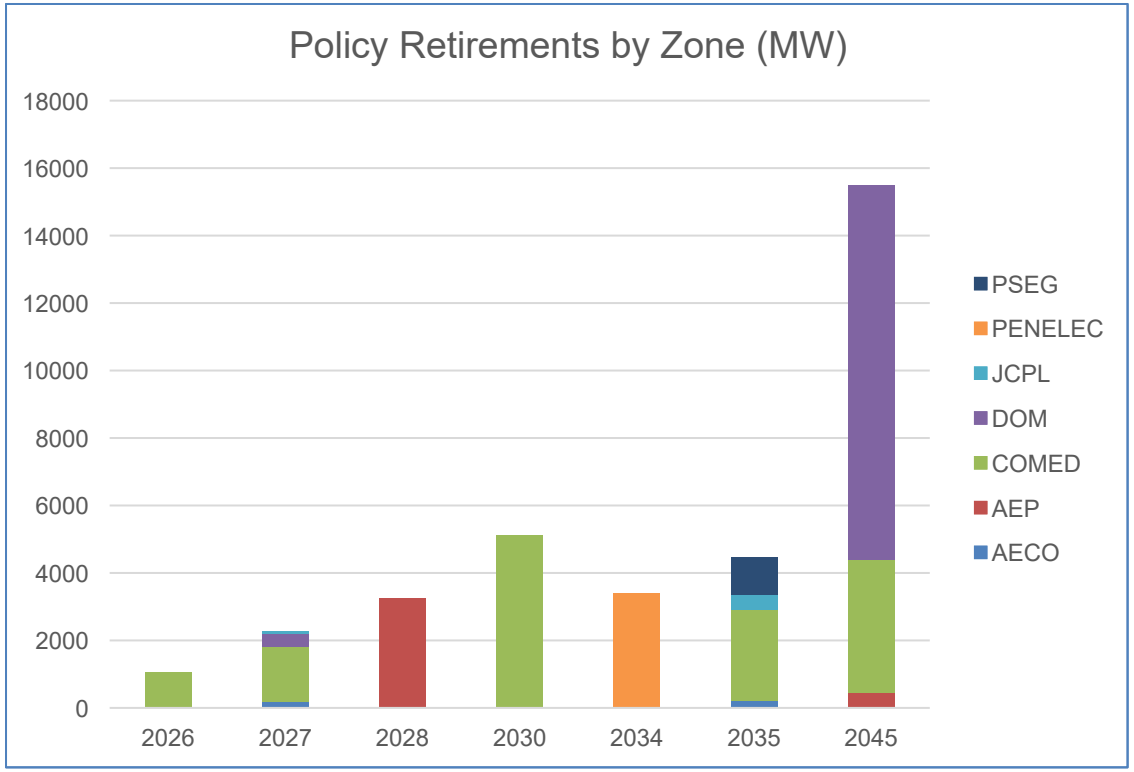
State RPS Policy



*PJM will model the geographic and technology eligibility rules for RPS Policies
**The complete policy assumptions are available in the ISAC policy workbook: https://www.pjm.com/-/media/DotCom/committees-groups/state-commissions/isac/postings/2026-rtep-isac-assumptions-submission.xlsx

Policy Retirements



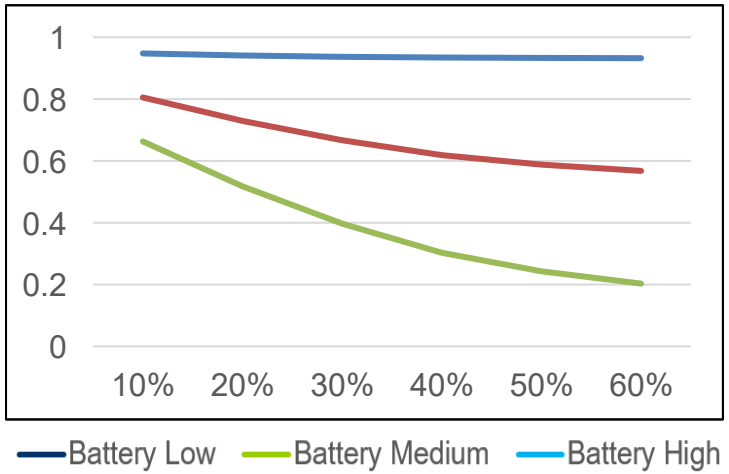


Resource Adequacy

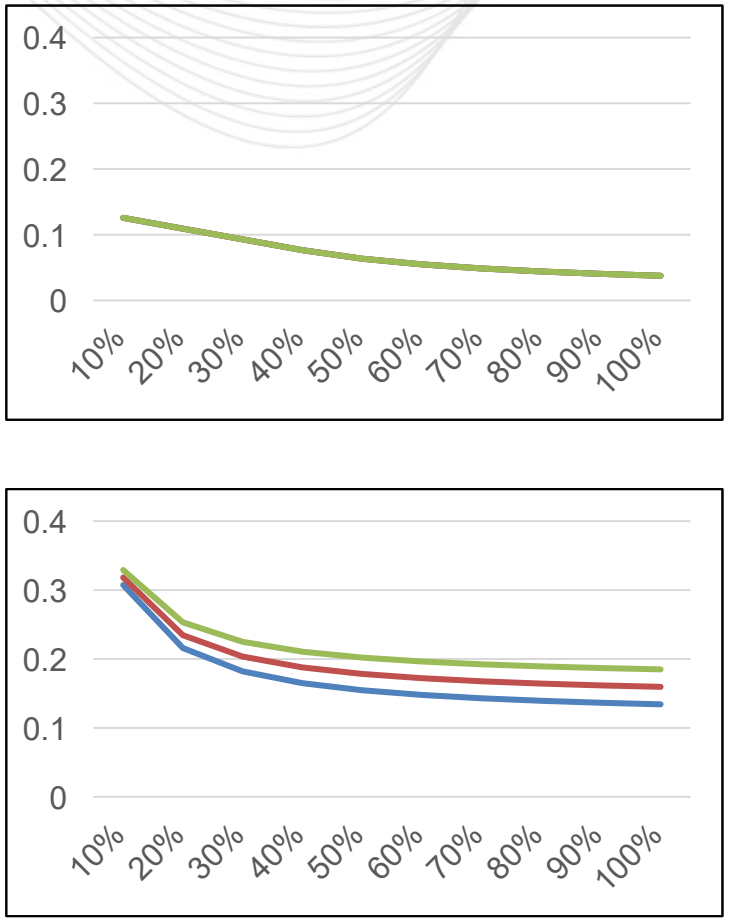
- Enforce the 1-in-10 resource adequacy constraint in the model
- Set ELCC-based capacity constraints to obtain resource adequate expansion (see next slide for ELCC curves)

ELCC Assumptions

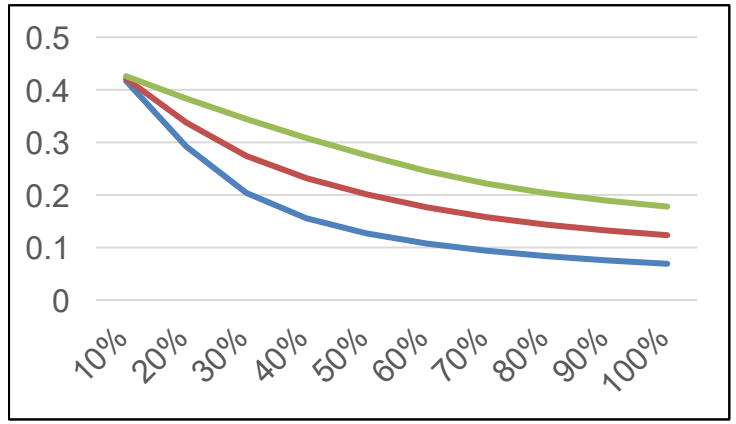
Battery



Onshore



Solar



- Solar winter ELCC set to 0
- Hybrid: solar ELCC + 0.5 battery ELCC
- Offshore: 1.7 × onshore ELCC
- CC and CT: 0.95 summer, 0.85 winter
- Coal: 0.87
- Nuclear: 0.99

Starting Resource Mix and Build Limits

- Starting resource mix: Consistent with 2026 RTEP model-year 2031
- Build limits are based on the PJM's generation interconnection queue: Build up to 2x of existing generation + queue by 2034, 3x by 2045 (for Virginia 3x,10x respectively)

Contact

Facilitator:
Eric Hsia, Eric.Hsia@pjm.com

Secretary:
Joshua Stephenson, Joshua.Stephenson@pjm.com

SME/Presenter:
Wenzheng Qiu, Wenzheng.Qiu@pjm.com

Emmanuele Bobbio, Emmanuele.Bobbio@pjm.com

2026 RTEP Assumptions

Member Hotline

(610) 666 – 8980

(866) 400 – 8980

custsvc@pjm.com

PROTECT THE POWER GRID

THINK BEFORE YOU CLICK!

Be alert to malicious phishing emails.

Report suspicious email activity to PJM.

(610) 666-2244 / it_ops_ctr_shift@pjm.com

Revision History

Version No.	Date	Description
1	04/2/2026	• Original slides posted