2023 PJM Reserve Requirement Study

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PJM Resource Adequacy Planning

December 29, 2023

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I. Results and Recommendations

PJM RRS Executive Summary

- The PJM Reserve Requirement Study's (RRS) purpose is to determine the Forecast Pool Requirement (FPR) for future Delivery Years (DY). Based on the study assumptions, Installed Reserve Margin (IRM) values for future DY are also derived. In accordance with the Reliability Pricing Model (RPM) auction schedule, results from this study will re-establish the FPR for the 2024/2025, 2025/2026, and 2026/2027 DYs and establish the FPR for the 2027/2028 DY.

- PJM also performs this Study to satisfy the North America Electric Reliability Corporation (NERC) / ReliabilityFirst (RF) Adequacy Standard BAL-502-RFC-03, Planning Resource Adequacy Analysis, Assessment and Documentation. This Standard requires that the Planning Coordinator performs and documents a resource adequacy analysis that applies a Loss of Load Expectation (LOLE) of one occurrence in ten years. Per the October 2019 audit, PJM was found to be fully compliant with Standard BAL-502-RFC-03.

- Per the 2023 RRS Assumptions, PJM performed the 2023 RRS using two software tools: the legacy tool, PRISM, and the recently developed hourly loss of load probability model employed to perform the ELCC calculations. PJM calculated FPR and IRM values with the two tools. PJM recommends to use the results produced by PRISM. This recommendation is based on the fact that the load uncertainty, the main driver for the FPR result, modeled by PRISM is closer to the overall load uncertainty modeled in the 2023 PJM Load Forecast. Results of the comparison between PRISM and the hourly loss of load probability model are provided in Appendix B.

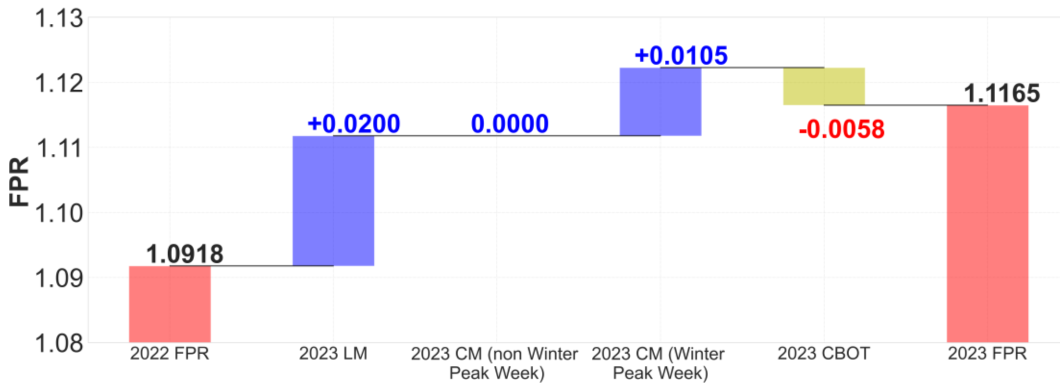
- Based on the above, PJM Staff recommends a **1.1170 FPR for the 2024/2025 Delivery Year, a 1.1171 FPR for the 2025/2026 Delivery Year, a 1.1172 FPR for the 2026/2027 Delivery Year, and a 1.1165 FPR for the 2027/2028 Delivery Year**. These FPR values are the key parameters for the Reliability Requirement calculation in RPM.

- The IRM values associated with the above recommended FPR values are 17.7% for 2024/2025, 17.7% for 2025/2026, 17.7% for 2026/2027 and 17.6% for 2027/2028.

- The 1.1165 (11.65%) FPR for 2027/2028 calculated in this year's study represents an increase of 2.47 percentage points with respect to the FPR computed for 2026/2027 in last year's study (1.0918 or 9.18%). Assuming a forecasted annual peak load of around 150,000 MW, this FPR increase corresponds to an increase in the Reliability Requirement of around 150,000 MW x 0.0247 = 3,705 MW. The FPR increase can be attributed to the factors and their estimated corresponding quantitative impacts depicted in Figure I-1 below.

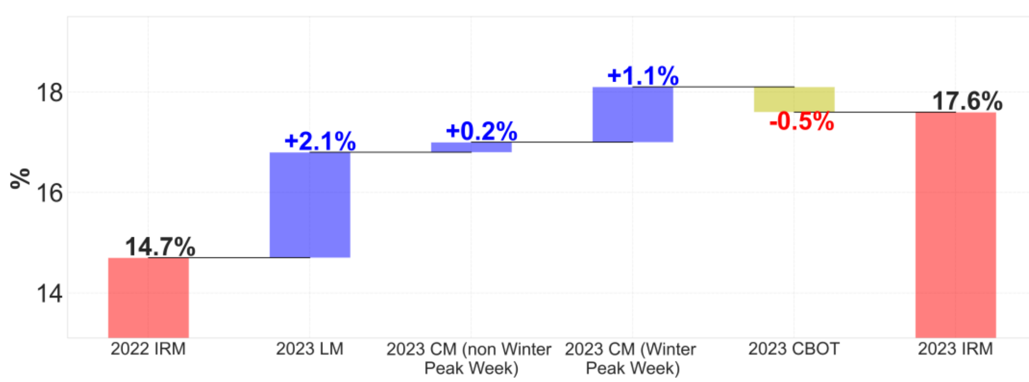
- The increase in the FPR is driven by the new 2023 Load Model and the 2023 Capacity Model (in the Winter Peak Week), whose joint impact more than offsets the downward pressure on the FPR exerted by the 2023 Capacity Benefit of Ties (CBOT).

Figure I-1: 2023 Forecast Pool Requirement Waterfall Chart



- The 17.6% IRM for 2027/2028 calculated in this year's study is also higher than the IRM computed for 2026/2027 in last year's study. As with the FPR, the increase in the IRM is driven by the new 2023 Load Model and the 2023 Capacity Model (in the Winter Peak Week), whose joint impact more than offsets the downward pressure on the FPR exerted by the 2023 Capacity Benefit of Ties (CBOT) as shown in Figure I-2.
- The 2023 Load Model puts upward pressure on both, the IRM and the FPR, relative to the 2022 Load Model, due to higher load uncertainty. This means that the load model selected for the 2023 study has higher values for loads greater than the forecasted annual peak (e.g., the 90/10 annual peak load value) than the 2022 study. The 2023 load model in the RRS reflects the higher load uncertainty produced by the 2023 PJM Load Forecast (in fact, the 2023 load model was selected because it was a good match for the annual peak distribution in the 2023 PJM Load Forecast). In turn, the 2023 PJM Load Forecast produces higher values for loads above the forecasted annual peak as a result of the switch to an hourly load forecast model in 2022. This switch allowed PJM to improve the forecast model by better aligning historical hourly peak load values with hourly values for the factors driving load (especially, weather).

Figure I-2: 2023 Installed Reserve Margin Waterfall Chart



- The 2023 Capacity Model in the Winter Peak Week puts upward pressure on both, the IRM and the FPR, relative to the 2022 Capacity Model in the Winter Peak Week, due to a higher probability of experiencing a large volume of correlated forced outages during the winter peak week. As indicated in the 2023 RRS Assumptions, PJM included the winter resource performance data during the week of Winter Storm Elliott (WSE) in the development of the winter capacity model. Also, motivated by the performance during WSE, PJM decided to include the winter resource performance data from the week of the January 7th, 2014 Polar Vortex in the development of the winter capacity model (in previous years' studies, including 2022, this observation was excluded from the study). The high volume of correlated outages observed during these two events drives risk into the winter season, increasing the IRM and also the FPR.

- The 2023 CBOT is the only main driver of the RRS that puts downward pressure on both, the IRM and the FPR, relative to the 2022 CBOT. The 2023 CBOT was calculated as the average of 7 CBOT values (the historical CBOT values used in the last 6 RRS plus the value calculated this year with PRISM). This resulted in a 2023 CBOT equal to 1.5% which represents an increase of 0.5 percentage points relative to the 1.0% used in the 2022 RRS. A commensurate impact reducing the FPR and IRM can be observed in Figure I-1 and Figure I-2.

- The 2023 Capacity Model in weeks other than the Winter Peak Week has no impact on the FPR while putting upward pressure on the IRM compared to the corresponding model in the 2022 RRS. This is caused by a slightly higher average EEFORd in the 2023 RRS (5.9%) relative to the average EEFORd in the 2022 RRS (5.7%).

- The results of the 2023 RRS are summarized below in Table I-1. PJM Staff recommends the values shown in bold in the following table.

Table I-1: 2023 Reserve Requirement Study Summary Table

RRS Year	Delivery Year Period	Recommended IRM	Average EFORd	Recommended FPR
2023	2024 / 2025	**17.7%**	5.10%	**1.1170**
2023	2025 / 2026	**17.7%**	5.09%	**1.1171**
2023	2026 / 2027	**17.7%**	5.08%	**1.1172**
2023	2027 / 2028	**17.6%**	5.06%	**1.1165**

- For comparison purposes, the results from the 2022 RRS Study are below in Table I-2:

Table I-2: 2022 Reserve Requirement Study Summary Table

RRS Year	Delivery Year Period	Recommended IRM	Average EFORd	Recommended FPR
2022	2023 / 2024	**14.9%**	4.87%	**1.0930**
2022	2024 / 2025	**14.8%**	4.83%	**1.0926**
2022	2025 / 2026	**14.7%**	4.81%	**1.0918**
2022	2026 / 2027	**14.7%**	4.81%	**1.0918**

- The mathematical formula that describes the relationship between IRM and FPR, FPR = (1 + IRM) x (1 – Average EFORd), depends on the EFORd concept which is not directly applicable to resources such as ELCC Resources and DR. Therefore, those resources are excluded from the study.

- The Winter Weekly Reserve Target (WWRT) for the **2023/2024 winter period is recommended to be 28% for December 2023, 30% for January 2024, and 25% for February 2024**. The analysis supporting this recommendation is detailed in the "Operations Related Assessments" section of this report.

- The winter peak week capacity model changes approved by the Markets and Reliability Committee (MRC) in June 2018 and first implemented in the 2018 RRS were also used in the 2023 RRS. These changes impacted the FPR and IRM in the 2023 RRS as illustrated in Figure I-1 and Figure I-2. The recommended WWRT value for January 2024 described in the bullet point above is also impacted by these changes due to the fact that the winter peak week is modeled to occur in January, 2024.

- The IRM and FPR values recommended in Table I-1 above are reviewed and considered for endorsement by the following succession of groups.
    - Resource Adequacy Analysis Subcommittee (RAAS)
    - Planning Committee (PC)
    - Markets and Reliability Committee (MRC)
    - PJM Members Committee (MC)
    - PJM Board of Managers (for final approval)

- PJM's Probabilistic Reliability Index Study Model (PRISM) program is the reliability modeling tool used to calculate the recommended values above. PRISM utilizes a two-area Loss of Load Probability (LOLP) modeling approach consisting of: Area 1 - the PJM RTO and Area 2 - the neighboring World.

- The PJM RTO includes the PJM Mid-Atlantic Region, Allegheny Energy (APS), American Electric Power (AEP), Commonwealth Edison (ComEd), Dayton Power and Light (Dayton), Dominion Virginia Power (Dom), Duquesne Light Co. (DLCO), American Transmission System Inc. (ATSI), Duke Energy Ohio and Kentucky (DEOK), East Kentucky Power Cooperative (EKPC), and Ohio Valley Electric Corporation (OVEC).

- The Outside World (or World) area consists of the North American Electric Reliability Corporation (NERC) regions adjacent to PJM. These regions include New York ISO (NYISO) from the Northeast Power Coordinating Council (NPCC), TVA and VACAR from the South Eastern Reliability Corporation (SERC), and the Midcontinent Independent System Operator (MISO) (excluding MISO-South).

- As indicated above, the 2023 CBOT was calculated as the average of 6 historical CBOT values and the value calculated with PRISM in 2023. To derive the 2023 value in PRISM, a Capacity Benefit Margin (CBM) of 3,500 MW was assumed. This serves as a maximum limit on the amount of external capacity assistance from the World into PJM. The CBM is set to 3,500 MW per Schedule 4 of the PJM Reliability Assurance Agreement.

- As mentioned above, the 2023 RRS excludes ELCC Resources from the capacity model (instead, their capacity values are calculated in a separate study, the Effective Load Carrying Capability, ELCC, study). The 2023 RRS assumptions were endorsed at the June 6, 2023 Planning Committee meeting.

- There is a modeled net addition of approximately 3,000 MW of non-ELCC generation within the PJM RTO over the period 2023-2027. This reflects approximately 6,200 MW of new non-ELCC generation and 3,200 MW of retired non-ELCC generation.

- For the first time, the load model time period 2013-2019 was used in the RRS study. This load model time period was endorsed at the August 8, 2023 Planning Committee meeting.

- Consistent with the requirements of ReliabilityFirst (RF) Standard BAL-502-RFC-03 - Resource Planning Reserve Requirements, the 2023 RRS provides an eleven-year resource adequacy projection for the planning horizon that begins June 1, 2023 and extends through May 31, 2034. (See Table I-4)

Results from the last ten RRS Reports are summarized below in Table I-3:

Table I-3: Historical RRS Parameters

RRS Year	Delivery Year	Calculated IRM	**Approved IRM**	Avg. EFORd	**FPR**
2013	2014/2015	16.2%	**16.2%**	6.66%	**1.0926**
2013	2015/2016	15.7%	**15.7%**	6.26%	**1.0920**
2013	2016/2017	15.7%	**15.7%**	6.29%	**1.0917**
2013	2017/2018	15.7%	**15.7%**	6.29%	**1.0916**
2014	2015/2016	15.6%	**15.6%**	6.19%	**1.0913**
2014	2016/2017	15.5%	**15.5%**	6.30%	**1.0896**
2014	2017/2018	15.7%	**15.7%**	6.34%	**1.0911**
2014	2018/2019	15.7%	**15.7%**	6.35%	**1.0835**
2015	2016/2017	16.4%	**16.4%**	6.57%	**1.0952**
2015	2017/2018	16.5%	**16.5%**	6.59%	**1.0959**
2015	2018/2019	16.5%	**16.5%**	6.58%	**1.0883**
2015	2019/2020	16.5%	**16.5%**	6.60%	**1.0881**
2016	2017/2018	16.6%	**16.6%**	6.54%	**1.0967**
2016	2018/2019	16.7%	**16.7%**	6.59%	**1.0901**
2016	2019/2020	16.6%	**16.6%**	6.59%	**1.0892**
2016	2020/2021	16.6%	**16.6%**	6.59%	**1.0892**
2017	2018/2019	16.1%	**16.1%**	6.07%	**1.0905**
2017	2019/2020	15.9%	**15.9%**	5.99%	**1.0896**
2017	2020/2021	15.9%	**15.9%**	5.97%	**1.0898**
2017	2021/2022	15.8%	**15.8%**	5.89%	**1.0898**
2018	2019/2020	16.0%	**16.0%**	6.08%	**1.0895**
2018	2020/2021	15.9%	**15.9%**	6.04%	**1.0890**
2018	2021/2022	15.8%	**15.8%**	6.01%	**1.0884**
2018	2022/2023	15.7%	**15.7%**	5.90%	**1.0887**
2019	2020/2021	15.5%	**15.5%**	5.78%	**1.0882**
2019	2021/2022	15.1%	**15.1%**	5.56%	**1.0870**
2019	2022/2023	14.9%	**14.9%**	5.42%	**1.0868**
2019	2023/2024	14.8%	**14.8%**	5.40%	**1.0860**
2020	2021/2022	14.7%	**14.7%**	5.22%	**1.0871**
2020	2022/2023	14.5%	**14.5%**	5.08%	**1.0868**
2020	2023/2024	14.4%	**14.4%**	5.04%	**1.0863**
2020	2024/2025	14.4%	**14.4%**	5.03%	**1.0865**
2021	2022/2023	14.9%	**14.9%**	5.08%	**1.0906**
2021	2023/2024	14.8%	**14.8%**	5.04%	**1.0901**
2021	2024/2025	14.7%	**14.7%**	5.02%	**1.0894**
2021	2025/2026	14.7%	**14.7%**	5.02%	**1.0894**
2022	2023/2024	14.9%	**14.9%**	4.87%	**1.0930**
2022	2024/2025	14.8%	**14.8%**	4.83%	**1.0926**
2022	2025/2026	14.7%	**14.7%**	4.81%	**1.0918**
2022	2026/2027	14.7%	**14.7%**	4.81%	**1.0918**

Introduction

Purpose

The annual PJM Reserve Requirement Study (RRS) is performed to comply with the Reliability Principles and Standards as defined in the PJM Reliability Assurance Agreement (RAA) and ReliabilityFirst (RF) Standard BAL-502-RFC-03. This study is conducted each year in accordance with PJM Manual 20 (M-20), PJM Resource Adequacy Analysis. M-20 focuses on the process and procedure for establishing the resource adequacy (capacity) required to reliably serve customer load in the PJM RTO.

Also, the RRS results are key inputs to the PJM Reliability Pricing Model (RPM). More specifically, the FPR is used to calculate the Reliability Requirement for the PJM Regional Transmission Organization (RTO) in RPM Auctions.

Finally, the results of the RRS are also incorporated into PJM's Regional Transmission Expansion Plan (RTEP) process for the enhancement and expansion of the transmission system in order to meet the demands for firm transmission service in the PJM Region.

The timetable for calculating and approving the IRM and FPR values is shown in the June 2023 study assumptions letter to the PC, reviewed at the June 6, 2023 PC meeting.

Regional Modeling

This study examines the combined PJM footprint area (shown in Figure I-3) that consists of the PJM Mid-Atlantic Region plus Allegheny Energy (APS), American Electric Power (AEP), Commonwealth Edison (ComEd), Dayton Power and Light (Dayton), Dominion Virginia Power (DOMVP), Duquesne Light Co. (DLCO), American Transmission System Inc. (ATSI), Duke Energy Ohio and Kentucky (DEOK), East Kentucky Power Cooperative (EKPC) and Ohio Valley Electric Corporation (OVEC).

Areas adjacent to the PJM Region are referred to as the World (shown in Figure I-4) and consist of MISO (excluding MISO-South), TVA and VACAR (both in SERC), and NYISO from the Northeast Power Coordinating Council (NPCC). Areas outside of PJM and the World are not modeled in this study.

Figure I-3: Combined PJM Region Modeled

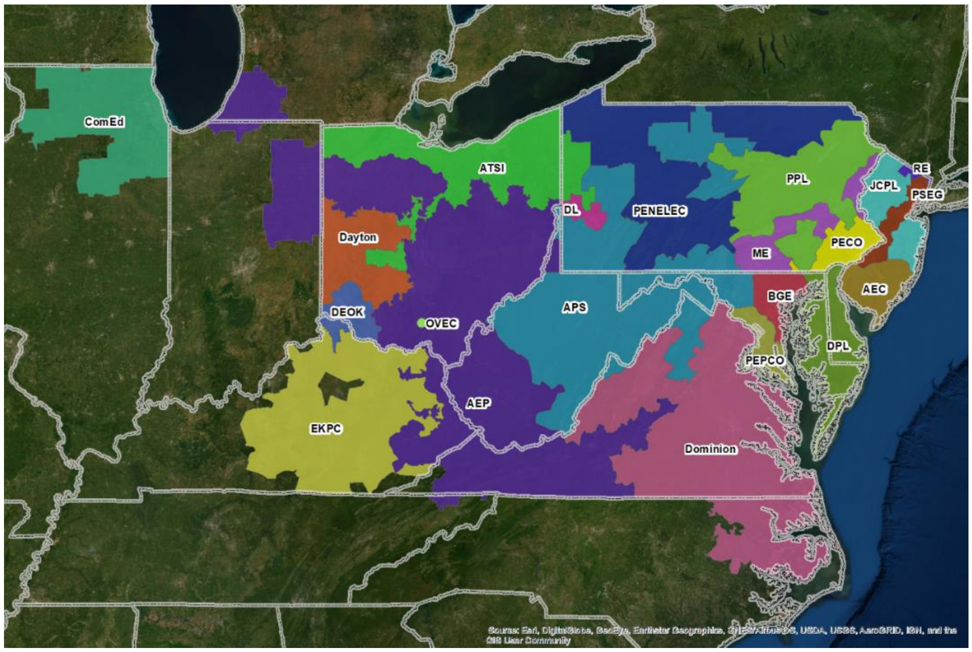
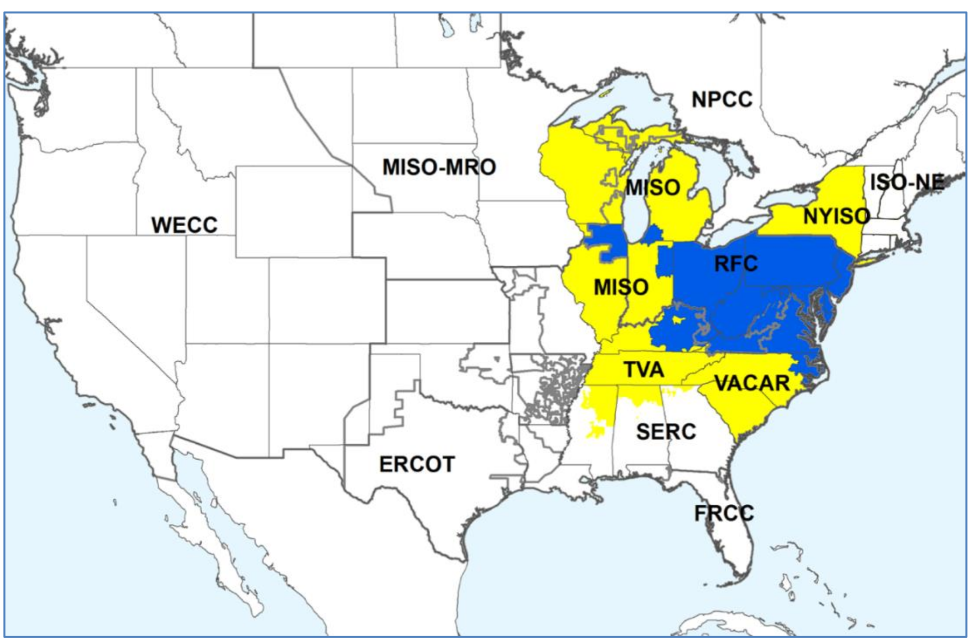


Figure I-4: PJM RTO, World and Non-Modeled Regions (PJM Region in blue)



Summary of RRS Results

Eleven-Year RRS Results

Table I-4 shows an eleven-year forward projection from the study for informational purposes. The Delivery Years for which the parameters must be reported are highlighted in yellow. Note that the forecasted Forecast Pool Requirement in column L exceeds the FPR in column D for each of the next eleven Delivery Years. The study, therefore, indicates that given the modeled resource additions to the system in the next eleven years, there are no gaps between the needed amount of unforced capacity reserves and the projected amount of unforced capacity over the eleven-year study period.

Table I-4: Eleven-Year Reserve Requirement Study

	Calculated IRM/FPR				Installed Capacity					Unforced Capacity		
	A	B	C	D	E	F	G	H	I	J	K	L
Delivery Year	IRM PJM RTO % (2 area)	Average PJM EEFORd %	Average Weekly Maintenance %	Forecast Pool Require-ment (FPR)	Capacity MW	Restricted Load MW	Forecast Reserve PJMRTO %	Forecast Unrestricted Reserve PJM RTO %	ELCC Resources Nameplate MW	Unforced Capacity (UCAP MW)	Unforced Capacity ELCC Resources (UCAP MW)	Forecast Forecast Pool Requirement PJMRTO
2023	17.7%	6.0%	8.5%	1.1170	167,107	141,771	17.9%	12.1%	24,958	158,584	11,730	1.2013
2024	17.7%	6.0%	8.4%	1.1170	168,194	142,340	18.2%	12.3%	32,264	159,616	14,841	1.2256
2025	17.7%	5.9%	8.3%	1.1171	168,704	143,471	17.6%	11.8%	41,483	160,117	17,423	1.2375
2026	17.7%	5.9%	8.4%	1.1172	169,254	145,221	16.5%	10.8%	49,598	160,656	18,847	1.2361
2027	17.6%	5.9%	8.3%	1.1165	170,079	146,702	15.9%	10.2%	52,114	161,473	18,761	1.2286
2028	17.6%	5.9%	8.4%	1.1166	170,166	148,086	14.9%	9.3%	52,774	161,573	17,943	1.2122
2029	17.6%	5.9%	8.4%	1.1166	170,166	149,277	14.0%	8.4%	53,054	161,573	16,447	1.1925
2030	17.6%	5.9%	8.4%	1.1166	170,166	150,220	13.3%	7.8%	54,564	161,573	15,824	1.1809
2031	17.6%	5.9%	8.4%	1.1166	170,166	151,232	12.5%	7.1%	54,564	161,573	15,824	1.1730
2032	17.6%	5.9%	8.4%	1.1166	170,166	152,186	11.8%	6.4%	54,564	161,573	15,824	1.1657
2033	17.6%	5.9%	8.4%	1.1166	170,166	153,213	11.1%	5.7%	54,564	161,573	15,824	1.1578

Calculated IRM/FPR Columns

- Column A and Column D are at an LOLE criterion of 1 day in 10 years (if the emergency imports from neighboring regions into PJM, i.e. the CBOT, are included as reserves)
- Column A and Column D are based on the PRISM solved load, not the January 2023 load forecast values issued by PJM.
- Calculated IRM and FPR results are determined using a 3,500 MW Capacity Benefit Margin (CBM).
- The Average Effective Equivalent Demand Forced outage rate (EEFORd) (column B) is a pool-wide average effective equivalent demand forced outage rate for all units included in the study. These are not the forced outage rates used in the RAA Obligation formula (as mentioned earlier in the document, EFORd values are used in the FPR formula). The EEFORd of each unit is based on a five-year period (2018-2022, for this year's study).
- The average weekly maintenance (column C) is the percentage of the average annual total capacity in the model out on weekly planned maintenance.

Installed Capacity Columns

- The capacity values in Column E include external firm capacity purchases and sales. For the entire study period, they exclude all ELCC Resources and Demand Resources.
- 2,500 MW of unit deratings were modeled to reflect generator performance impacts during extreme hot and humid summer conditions. These 2,500 MW are counted as capacity in the Column E value.
- The Restricted Load in Column F corresponds to Total Internal Demand (at peak time) minus load management (i.e. DR) as per the 2023 PJM Load Forecast.
- Reserves in Column G (as well as the capacity value in Column E) include about 6,200 MW of new generation projects (excluding ELCC Resources) identified through the Regional Transmission Expansion Plan (RTEP). Generation projects in the PJM interconnection queue with a signed Interconnection Service Agreement (ISA) are included in the study. The values in Column G are also reflective of around 3,200 MW of announced deactivations.
- The values in Column I are the existing and expected MW amount of nameplate ELCC Resources in each of the next 11 years. Projects that had a signed Interconnection Service Agreement (ISA) or a Wholesale Market Participation Agreement (WMPA) as of June 2023 are included in this column. As mentioned earlier in this report, ELCC Resources are not included in the RRS capacity model. The capacity value of ELCC Resources is calculated via the ELCC study[1].

Unforced Capacity Columns

- Column J includes the estimated amount of Unforced Capacity projected for non-ELCC generation resources. The Unforced Capacity of non-ELCC generation resources is derived by using the EFORd of such resources, ICAP x (1 – EFORd).
- Column K includes the estimated amount of Unforced Capacity projected for ELCC generation resources. As noted above, the Unforced Capacity of ELCC generation resources is derived via the ELCC study.
- Column L is calculated by adding up the Unforced Capacity from columns J and K and the result is divided by the Restricted Load (Column F). Therefore, Column L shows the forecasted Forecast Pool Requirement values. These values can be compared to the Forecast Pool Requirement values (Column D), which show the required amount of unforced capacity to meet the 1 in 10 criterion.
- Note that the values in Column L starting include a large amount of planned units that are currently in the interconnection queue. Therefore, actual unforced capacity levels may differ significantly from those shown in Column L.

Key Observations

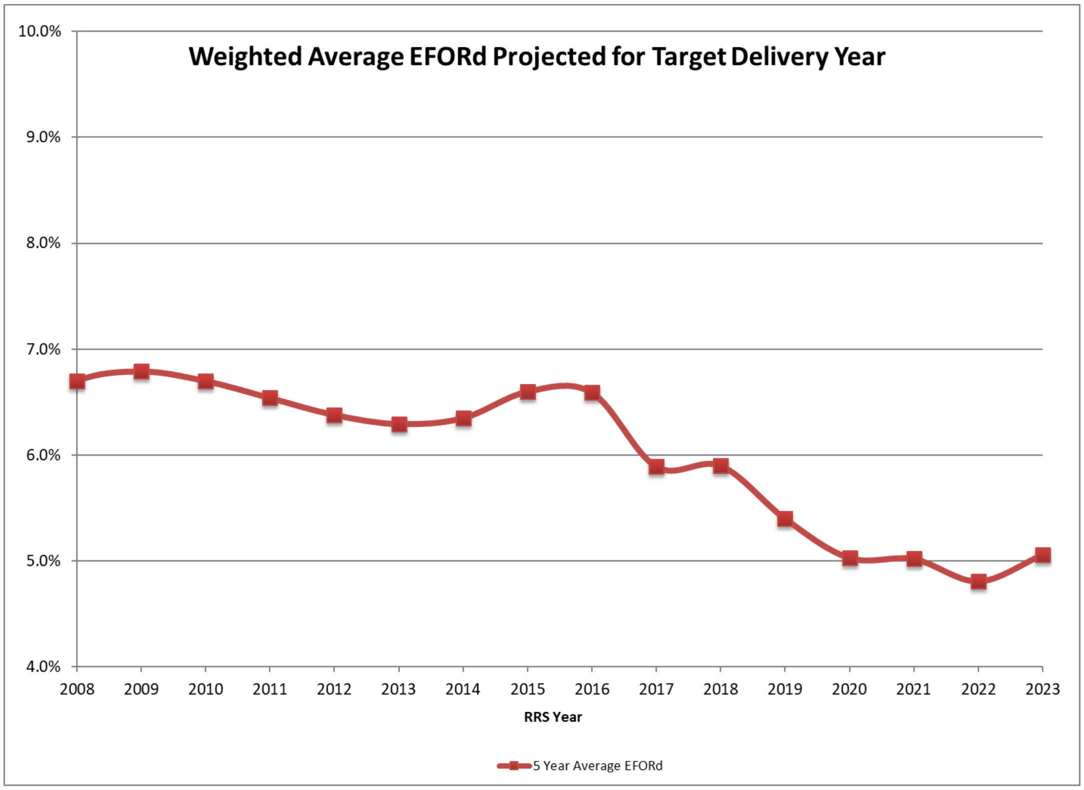
- General Trends and Observations
    - Pool wide average forced outage rate values (EFORd) for the target Delivery Year, in each of the last 15 RRS capacity models, are shown in Figure I-5. The forced outage rates of each unit are based on the

[1] https://www.pjm.com/-/media/planning/res-adeq/elcc/elcc-report-december-2022.ashx

historical five-year period used in a given study. It is important to note that the collection of generators included in each year's case varies greatly over time as new generators are brought in-service, some generators retire or mothball, and new generators are added due to PJM market expansion.

- As shown in Figure I-5, expected average unit performance in the 2023 study model is slightly worse than the expected unit performance in the 2022 study model (the capacity-weighted average EFORd in the 2023 RRS is 5.06% while in the 2022 RRS it was 4.81%).

Figure I-5: Historical Weighted-Average EFORd (Five-Year Period)



- As indicated above, the 2023 CBOT was calculated as the average of 6 historical CBOT values and the value calculated with PRISM in 2023. To derive the 2023 value in PRISM, the World reserves were assessed and modeled in a similar manner as performed in previous RRS studies. Among the regions modeled as part of the World, the New York and MISO regions have firm reserve requirements, while the TVA and VACAR regions have soft targets. The soft targets chosen are consistent with general statements of the NERC targets for these regions.
- ELCC Resources are included in the capacity model of the World region. For wind and solar resources it is assumed that their ICAP is equal to their UCAP which is in turn equal to their capacity value. This assumption implies that the modeled EEFORd of wind and solar resources in the World region is 0%.

Table I-5: World Regions Reserve Level

	NCP	IRM	Diversity	CP	LM
NY	32018	19.9%	0.9556	30595	813
MISO	92463	15.9%	0.9853	91105	4557
TVA	42119	15.0%	0.9592	40402	1638
VACAR	44878	15.0%	0.9559	42900	1130
Total Composite Region =	211478			205002	8138

LM: Load Management NCP: Non-Coincident Peak CP: Coincident Peak

Data Sources

MISO and NY - 2022 NERC ES&D Report - Peak Hour Demand Seasonal, 1st Year column
MISO excludes MISO-South
MISO and NY LM Total from 2022 NERC ES&D Report - Demand & Resources - Summer, Controllable and Dispatchable Demand Response - Available (Year 1)
TVA and VACAR - 2022 NERC ES&D Report
Peak Hour Demand Seasonal, 1st Year column. TVA = SERC C (Winter) VACAR = SERC E (Winter)
Demand & Resources - Winter, Controllable and Dispatchable Demand Response - Available (Year 1). TVA = SERC C, VACAR = SERC E
NY is modeled at its approved IRM as per the documents below:
https://www.nysrc.org/wp-content/uploads/2023/03/2023-IRM-Study-Technical-Report-12-14-2022-Final-rev-3.pdf
MISO is modeled at its approved Summer IRM as per the documents below:
https://cdn.misoenergy.org/PY%202023-2024%20LOLE%20Study%20Report626798.pdf
TVA and VACAR are modeled at the soft target IRM of 15%.

- Load diversity between PJM and the World is addressed by two modeling assumptions. First, the historical period used to construct the hourly load model is the same for PJM and the World. Second, the world load model corresponds to coincident peaks from the four individual sub-regions.

- The PJM IRM is reduced by 1.5% due to the CBOT (from 19.1% to 17.6 %). Similarly, the PJM FPR is reduced by 0.0142 (from 1.1317 to 1.1165). Based on the forecasted load for 2027/2028, this FPR reduction eliminates the need for about 154,275 MW x 0.0142 = 2,191 MW of unforced capacity.

Recommendations

- Installed Reserve Margin (IRM) — based on the study results and the additional considerations mentioned above, PJM recommends endorsement of an IRM value of 17.7% for the 2024/2025 Delivery Year, 17.7% for the 2025/2026 Delivery Year, 17.7% for the 2026/2027 Delivery Year, and 17.6% for the 2027/2028 Delivery Year.

- Forecast Pool Requirement (FPR) — the IRM is converted to the FPR for use in determining capacity obligations. The FPR expresses the reserve requirement in unforced capacity terms. The FPR is defined by the following equation:

    - FPR = (1 + IRM) * (1 – PJM Avg. EFORd)

  The above equation depends on the EFORd concept which is not directly applicable to ELCC Resources and DR.

- Based on the recommended IRM values, the resulting FPRs are:

        - 2024 / 2025 Delivery Year FPR = (1.177) * (1 – 0.0510) = 1.1170
        - 2025 / 2026 Delivery Year FPR = (1.177) * (1 – 0.0509) = 1.1171
        - 2026 / 2027 Delivery Year FPR = (1.177) * (1 – 0.0508) = 1.1172
        - 2027 / 2028 Delivery Year FPR = (1.176) * (1 – 0.0506) = 1.1165

  To calculate the Reliability Requirement in an RPM auction, the FPR is applied to the official 50/50 PJM Summer Peak Forecast for the corresponding delivery year.

- Winter Weekly Reserve Target — the recommended 2023 / 2024 Winter Weekly Reserve Target is 28% for December 2023, 30% for January 2024, and 25% for February 2024. This recommendation is discussed later in the report.

II. Supplemental Background, Figures, and Tables

Table II-1: Load Forecast for 2027 / 2028 Delivery Years

Month	PJMRTO Unrestricted Loads	WORLD Unrestricted Loads
June	0.944214	0.956465
July	1.000000	1.000000
August	0.978310	0.992623
September	0.871115	0.907889
October	0.697619	0.739544
November	0.742416	0.763185
December	0.842565	0.823110
January	0.899745	0.878996
February	0.851630	0.823738
March	0.810969	0.764171
April	0.716004	0.688531
May	0.816219	0.801992

Table II-2: PJM RTO Load Model Parameters (PJM LM 52809)

ARC Week	Mean Seasonal	Standard Deviation	ARC Week	Mean Seasonal	Standard Deviation
1	0.69008	0.10069	27	0.69001	0.05729
2	0.90609	0.07845	28	0.70953	0.06332
3	0.85822	0.06609	29	0.67606	0.05639
4	0.77483	0.08142	30	0.76125	0.05123
5	0.91890	0.09890	31	0.77668	0.08272
6	0.89265	0.07884	32	0.72106	0.05136
7	0.75378	0.06150	33	0.72471	0.06221
8	0.90400	0.09368	34	0.82669	0.09946
9	0.79063	0.08246	35	0.73345	0.05905
10	0.95184	0.09369	36	0.78713	0.08924
11	0.88640	0.05658	37	0.80967	0.08907
12	0.70436	0.06199	38	0.77178	0.05437
13	0.80243	0.08315	39	0.77324	0.06923
14	0.84820	0.05651	40	0.77672	0.06379
15	0.78226	0.05870	41	0.77016	0.04959
16	1.00000	0.06719	42	0.70855	0.04964
17	0.89051	0.07475	43	0.66438	0.05618
18	0.77132	0.05266	44	0.65974	0.03225
19	0.67849	0.05117	45	0.66196	0.03646
20	0.65459	0.04348	46	0.66764	0.07746
21	0.69780	0.07261	47	0.63974	0.07655
22	0.66520	0.04794	48	0.60394	0.05233
23	0.67758	0.07883	49	0.59283	0.03693
24	0.74302	0.08685	50	0.59322	0.04791
25	0.66645	0.06048	51	0.62115	0.04144
26	0.70738	0.09316	52	0.62668	0.06446

Table II-3: Intra-World Load Diversity

Annual Diversity

Area	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	23 year avg*
WORLD	2.14%	2.22%	3.52%	3.50%	2.59%	4.41%	5.67%	3.77%	2.29%	2.41%	2.73%	3.04%	2.11%	3.49%	3.35%	3.33%	2.66%	2.13%	2.62%	2.17%	2.44%	1.39%	7.96%	3.13%
MISO	0.22%	0.87%	1.70%	0.11%	0.96%	1.89%	8.18%	0.00%	1.21%	0.00%	1.14%	0.84%	0.20%	0.00%	2.40%	0.72%	1.79%	0.00%	1.00%	0.01%	0.00%	0.00%	10.56%	1.47%
NY	1.42%	1.39%	4.27%	1.62%	1.13%	6.07%	2.75%	3.75%	5.94%	4.18%	5.37%	6.02%	3.90%	3.59%	5.23%	6.22%	6.28%	5.62%	5.02%	5.97%	7.79%	4.04%	4.65%	4.44%
VACAR	4.19%	4.08%	4.93%	5.50%	4.02%	5.92%	5.26%	10.14%	1.72%	3.70%	3.17%	2.69%	3.61%	5.70%	3.21%	5.95%	2.28%	2.53%	4.35%	3.94%	4.74%	2.93%	6.83%	4.41%
TVA	3.83%	3.24%	4.68%	9.27%	5.07%	5.72%	4.43%	4.34%	2.13%	4.36%	3.24%	4.82%	2.52%	7.93%	3.61%	3.18%	2.42%	3.89%	2.63%	2.30%	2.59%	1.79%	5.74%	4.08%

Monthly Diversity

Month Number	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Forecast Shape**
1	87.9%	86.1%	84.3%	89.2%	84.1%	91.1%	84.2%	85.5%	86.2%	84.1%	89.1%	92.6%	85.3%	89.8%	89.4%	83.9%	83.8%	89.5%	86.1%	87.6%	85.9%	87.2%	91.9%	87.9%
2	83.1%	81.3%	79.3%	84.7%	79.5%	85.0%	79.9%	81.2%	81.8%	79.2%	83.7%	86.3%	81.0%	84.6%	83.7%	78.8%	79.3%	84.6%	81.3%	82.3%	81.0%	82.2%	86.2%	82.4%
3	77.5%	75.8%	74.3%	78.8%	74.4%	78.2%	74.9%	75.9%	76.2%	74.4%	77.4%	79.5%	76.0%	78.5%	77.4%	73.4%	74.4%	78.7%	75.7%	76.1%	75.9%	76.2%	79.8%	76.4%
4	69.5%	68.3%	67.6%	70.5%	67.7%	69.4%	67.9%	68.8%	68.2%	68.0%	69.0%	70.7%	68.8%	70.4%	69.4%	66.4%	67.5%	70.7%	68.2%	68.5%	68.7%	68.7%	70.8%	68.9%
5	80.7%	80.1%	79.6%	81.9%	79.7%	80.7%	79.7%	80.9%	79.8%	80.2%	80.2%	82.0%	80.4%	82.2%	81.0%	78.0%	79.8%	82.0%	79.9%	80.2%	80.8%	80.6%	81.5%	80.2%
6	95.3%	95.4%	95.1%	96.3%	94.9%	95.6%	95.1%	95.9%	94.9%	95.3%	95.5%	96.3%	95.6%	96.6%	95.8%	93.1%	95.5%	96.3%	95.2%	95.2%	96.1%	95.8%	95.8%	95.6%
7	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	99.0%	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**
8	99.4%	99.3%	98.8%	98.7%	99.3%	99.2%	99.0%	98.8%	100.0%	98.8%	99.0%	98.3%	98.7%	98.2%	98.9%	**100.0%**	99.1%	98.0%	98.5%	99.4%	98.6%	98.6%	99.3%	99.3%
9	91.0%	91.1%	90.7%	90.4%	90.9%	91.2%	90.8%	90.6%	92.3%	90.3%	90.9%	89.3%	90.2%	89.3%	90.7%	93.2%	91.0%	88.6%	90.2%	90.9%	90.8%	89.6%	91.5%	90.8%
10	74.4%	74.5%	74.6%	74.2%	74.0%	74.9%	74.5%	74.2%	75.9%	73.8%	74.5%	72.6%	73.8%	72.7%	74.4%	77.2%	74.4%	72.0%	74.1%	74.2%	74.7%	72.4%	75.4%	74.0%
11	76.0%	77.2%	76.5%	76.6%	75.4%	77.7%	76.2%	77.1%	78.0%	75.3%	76.2%	74.8%	76.3%	73.7%	76.3%	80.0%	76.3%	73.9%	76.0%	76.3%	76.5%	73.6%	78.2%	76.3%
12	81.8%	83.9%	82.8%	83.4%	81.2%	84.9%	82.5%	84.6%	84.6%	81.2%	81.9%	81.7%	82.9%	79.3%	82.2%	87.6%	82.4%	80.1%	82.4%	83.0%	82.4%	79.2%	85.6%	82.3%

**Annual Diversity is used to convert reported Subarea forecasts to coincident values associated with the World peak*
***Forecast shape takes into account historical diversity, current World composition, and forecasted World Subarea growth*

Table II-4: PJM RTO Fleet Class Average Generation Performance Statistics (2018-2022)

Start Date	End Date	Unit Type & Primary Fuel Category	Gen Class Key	EFORd	EEFORd	XEFORd	POF Weeks/Year	EMOF	Variance
1/1/2018	12/31/2022	FOSSIL All Fuel Types All Sizes	1	13.188%	14.696%	12.330%	4	2.938	28701
1/1/2018	12/31/2022	FOSSIL All Fuel Types 001-099	2	13.696%	14.785%	12.362%	3	1.978	3574
1/1/2018	12/31/2022	FOSSIL All Fuel Types 100-199	3	13.696%	14.785%	12.362%	3	1.978	3574
1/1/2018	12/31/2022	FOSSIL All Fuel Types 200-299	4	12.375%	14.250%	11.877%	5	3.854	34261
1/1/2018	12/31/2022	FOSSIL All Fuel Types 300-399	5	12.375%	14.250%	11.877%	5	3.854	34261
1/1/2018	12/31/2022	FOSSIL All Fuel Types 400-599	6	12.375%	14.250%	11.877%	5	3.854	34261
1/1/2018	12/31/2022	FOSSIL All Fuel Types 600-799	7	12.375%	14.250%	11.877%	5	3.854	34261
1/1/2018	12/31/2022	FOSSIL All Fuel Types 800-999	8	14.280%	14.250%	14.143%	5	3.854	34261
1/1/2018	12/31/2022	FOSSIL All Fuel Types 1000 Plus	9	14.280%	14.250%	14.143%	5	3.854	34261
1/1/2018	12/31/2022	FOSSIL Coal Primary All Sizes	10	13.188%	14.696%	12.330%	4	2.938	28701
1/1/2018	12/31/2022	FOSSIL Coal Primary 001-099	11	13.696%	14.785%	12.362%	3	1.978	3574
1/1/2018	12/31/2022	FOSSIL Coal Primary 100-199	12	13.696%	14.785%	12.362%	3	1.978	3574
1/1/2018	12/31/2022	FOSSIL Coal Primary 200-299	13	12.375%	14.250%	11.877%	5	3.854	34261
1/1/2018	12/31/2022	FOSSIL Coal Primary 300-399	14	12.375%	14.250%	11.877%	5	3.854	34261
1/1/2018	12/31/2022	FOSSIL Coal Primary 400-599	15	12.375%	14.250%	11.877%	5	3.854	34261
1/1/2018	12/31/2022	FOSSIL Coal Primary 600-799	16	12.375%	14.250%	11.877%	5	3.854	34261
1/1/2018	12/31/2022	FOSSIL Coal Primary 800-999	17	14.280%	14.250%	14.143%	5	3.854	34261
1/1/2018	12/31/2022	FOSSIL Coal Primary 1000 Plus	18	14.280%	14.250%	14.143%	5	3.854	34261
1/1/2018	12/31/2022	FOSSIL Oil Primary All Sizes	19	13.188%	14.696%	12.330%	4	2.938	28701
1/1/2018	12/31/2022	FOSSIL Oil Primary 001-099	20	13.696%	14.785%	12.362%	3	1.978	3574
1/1/2018	12/31/2022	FOSSIL Oil Primary 100-199	21	13.696%	14.785%	12.362%	3	1.978	3574
1/1/2018	12/31/2022	FOSSIL Oil Primary 200-299	22	12.375%	14.250%	11.877%	5	3.854	34261
1/1/2018	12/31/2022	FOSSIL Oil Primary 300-399	23	12.375%	14.250%	11.877%	5	3.854	34261
1/1/2018	12/31/2022	FOSSIL Oil Primary 400-599	24	12.375%	14.250%	11.877%	5	3.854	34261
1/1/2018	12/31/2022	FOSSIL Oil Primary 600-799	25	12.375%	14.250%	11.877%	5	3.854	34261
1/1/2018	12/31/2022	FOSSIL Oil Primary 800-999	26	14.280%	14.250%	14.143%	5	3.854	34261
1/1/2018	12/31/2022	FOSSIL Gas Primary All Sizes	28	13.188%	14.696%	12.330%	4	2.938	28701
1/1/2018	12/31/2022	FOSSIL Gas Primary 001-099	29	13.696%	14.785%	12.362%	3	1.978	3574
1/1/2018	12/31/2022	FOSSIL Gas Primary 100-199	30	13.696%	14.785%	12.362%	3	1.978	3574
1/1/2018	12/31/2022	FOSSIL Gas Primary 200-299	31	12.375%	14.250%	11.877%	5	3.854	34261
1/1/2018	12/31/2022	FOSSIL Gas Primary 300-399	32	12.375%	14.250%	11.877%	5	3.854	34261
1/1/2018	12/31/2022	FOSSIL Gas Primary 400-599	33	12.375%	14.250%	11.877%	5	3.854	34261
1/1/2018	12/31/2022	FOSSIL Gas Primary 600-799	34	12.375%	14.250%	11.877%	5	3.854	34261
1/1/2018	12/31/2022	FOSSIL Gas Primary 800-999	35	14.280%	14.250%	14.143%	5	3.854	34261
1/1/2018	12/31/2022	FOSSIL Lignite Primary All Sizes	37	13.188%	14.696%	12.330%	4	2.938	28701
1/1/2018	12/31/2022	NUCLEAR All Types All Sizes	38	1.019%	1.231%	1.007%	3	0.443	13850
1/1/2018	12/31/2022	NUCLEAR All Types 400-799	39	1.019%	1.231%	1.007%	3	0.443	13850
1/1/2018	12/31/2022	NUCLEAR All Types 800-999	40	1.019%	1.231%	1.007%	3	0.443	13850
1/1/2018	12/31/2022	NUCLEAR All Types 1000 Plus	41	1.019%	1.231%	1.007%	3	0.443	13850
1/1/2018	12/31/2022	NUCLEAR PWR All Sizes	42	1.019%	1.231%	1.007%	3	0.443	13850
1/1/2018	12/31/2022	NUCLEAR PWR 400-799	43	1.019%	1.231%	1.007%	3	0.443	13850
1/1/2018	12/31/2022	NUCLEAR PWR 800-999	44	1.019%	1.231%	1.007%	3	0.443	13850
1/1/2018	12/31/2022	NUCLEAR PWR 1000 Plus	45	1.019%	1.231%	1.007%	3	0.443	13850
1/1/2018	12/31/2022	NUCLEAR BWR All Sizes	46	1.019%	1.231%	1.007%	3	0.443	13850
1/1/2018	12/31/2022	NUCLEAR BWR 400-799	47	1.019%	1.231%	1.007%	3	0.443	13850
1/1/2018	12/31/2022	NUCLEAR BWR 800-999	48	1.019%	1.231%	1.007%	3	0.443	13850
1/1/2018	12/31/2022	NUCLEAR BWR 1000 Plus	49	1.019%	1.231%	1.007%	3	0.443	13850
1/1/2018	12/31/2022	NUCLEAR CANDU All Sizes	50	1.019%	1.231%	1.007%	3	0.443	13850
1/1/2018	12/31/2022	JET ENGINE All Sizes	51	10.061%	10.178%	9.213%	2	1.297	301
1/1/2018	12/31/2022	JET ENGINE 001-019	52	19.678%	19.630%	18.101%	1	1.266	28
1/1/2018	12/31/2022	JET ENGINE 20 Plus	53	9.862%	9.354%	9.026%	2	1.525	106
1/1/2018	12/31/2022	GAS TURBINE All Sizes	54	10.061%	10.178%	9.213%	2	1.297	301
1/1/2018	12/31/2022	GAS TURBINE 001-019	55	19.678%	19.630%	18.101%	1	1.266	28
1/1/2018	12/31/2022	GAS TURBINE 020-049	56	9.862%	9.354%	9.026%	2	1.525	106
1/1/2018	12/31/2022	GAS TURBINE 50 Plus	57	5.345%	5.833%	4.855%	3	1.206	527
1/1/2018	12/31/2022	COMBINED CYCLE All Sizes	58	4.179%	4.683%	3.895%	4	1.153	3226
1/1/2018	12/31/2022	HYDRO All Sizes	59	15.774%	17.901%	13.973%	1	4.832	44
1/1/2018	12/31/2022	HYDRO 001-029	60	15.774%	17.901%	13.973%	1	4.832	44
1/1/2018	12/31/2022	HYDRO 30 Plus	61	15.774%	17.901%	13.973%	1	4.832	44
1/1/2018	12/31/2022	PUMPED STORAGE All Sizes	62	2.994%	3.526%	2.535%	5	1.156	3867
1/1/2018	12/31/2022	MULTIBOILER/MULTI-TURBINE All Sizes	63	10.061%	10.178%	9.213%	2	1.297	301
1/1/2018	12/31/2022	DIESEL Landfill	64	23.051%	23.101%	22.572%	0	0.597	2
1/1/2018	12/31/2022	DIESEL All Sizes	65	9.244%	9.745%	7.510%	0	1.197	4
1/1/2018	12/31/2022	FOSSIL Oil/Gas Primary All Sizes	66	13.188%	14.696%	12.330%	4	2.938	28701
1/1/2018	12/31/2022	FOSSIL Oil/Gas Primary 001-099	67	13.696%	14.785%	12.362%	3	1.978	3574
1/1/2018	12/31/2022	FOSSIL Oil/Gas Primary 100-199	68	13.696%	14.785%	12.362%	3	1.978	3574
1/1/2018	12/31/2022	FOSSIL Oil/Gas Primary 200-299	69	12.375%	14.250%	11.877%	5	3.854	34261
1/1/2018	12/31/2022	FOSSIL Oil/Gas Primary 300-399	70	12.375%	14.250%	11.877%	5	3.854	34261
1/1/2018	12/31/2022	FOSSIL Oil/Gas Primary 400-599	71	12.375%	14.250%	11.877%	5	3.854	34261
1/1/2018	12/31/2022	FOSSIL Oil/Gas Primary 600-799	72	12.375%	14.250%	11.877%	5	3.854	34261
1/1/2018	12/31/2022	FOSSIL Oil/Gas Primary 800-999	73	14.280%	14.250%	14.143%	5	3.854	34261
1/1/2018	12/31/2022	Wind All Sizes	74	0.000%	0.000%	0.000%	0	0.000	0
1/1/2018	12/31/2022	Solar All Sizes	75	0.000%	0.000%	0.000%	0	0.000	0

Table II-5: Comparison of Class Average Values - 2022 RRS vs. 2023 RRS

Unit Type & Primary Fuel Category	Gen Class Key	EFORd Change	EEFORd Change	XEFORd Change	POF Change Weeks/Year	EMOF Change	Variance Change
FOSSIL All Fuel Types All Sizes	1	0.01	0.01	0.01	0.28	0.19	2138
FOSSIL All Fuel Types 001-099	2	0.01	0.01	0.01	0.24	0.10	-400
FOSSIL All Fuel Types 100-199	3	0.01	0.01	0.01	0.24	0.10	-400
FOSSIL All Fuel Types 200-299	4	0.01	0.01	0.01	0.10	0.22	2273
FOSSIL All Fuel Types 300-399	5	0.01	0.01	0.01	0.10	0.22	2273
FOSSIL All Fuel Types 400-599	6	0.01	0.01	0.01	0.10	0.22	2273
FOSSIL All Fuel Types 600-799	7	0.01	0.01	0.01	0.10	0.22	2273
FOSSIL All Fuel Types 800-999	8	0.00	0.01	0.00	0.10	0.22	2273
FOSSIL All Fuel Types 1000 Plus	9	0.00	0.01	0.00	0.10	0.22	2273
FOSSIL Coal Primary All Sizes	10	0.01	0.01	0.01	0.28	0.19	2138
FOSSIL Coal Primary 001-099	11	0.01	0.01	0.01	0.24	0.10	-400
FOSSIL Coal Primary 100-199	12	0.01	0.01	0.01	0.24	0.10	-400
FOSSIL Coal Primary 200-299	13	0.01	0.01	0.01	0.10	0.22	2273
FOSSIL Coal Primary 300-399	14	0.01	0.01	0.01	0.10	0.22	2273
FOSSIL Coal Primary 400-599	15	0.01	0.01	0.01	0.10	0.22	2273
FOSSIL Coal Primary 600-799	16	0.01	0.01	0.01	0.10	0.22	2273
FOSSIL Coal Primary 800-999	17	0.00	0.01	0.00	0.10	0.22	2273
FOSSIL Coal Primary 1000 Plus	18	0.00	0.01	0.00	0.10	0.22	2273
FOSSIL Oil Primary All Sizes	19	0.01	0.01	0.01	0.28	0.19	2138
FOSSIL Oil Primary 001-099	20	0.01	0.01	0.01	0.24	0.10	-400
FOSSIL Oil Primary 100-199	21	0.01	0.01	0.01	0.24	0.10	-400
FOSSIL Oil Primary 200-299	22	0.01	0.01	0.01	0.10	0.22	2273
FOSSIL Oil Primary 300-399	23	0.01	0.01	0.01	0.10	0.22	2273
FOSSIL Oil Primary 400-599	24	0.01	0.01	0.01	0.10	0.22	2273
FOSSIL Oil Primary 600-799	25	0.01	0.01	0.01	0.10	0.22	2273
FOSSIL Oil Primary 800-999	26	0.00	0.01	0.00	0.10	0.22	2273
FOSSIL Gas Primary All Sizes	28	0.01	0.01	0.01	0.28	0.19	2138
FOSSIL Gas Primary 001-099	29	0.01	0.01	0.01	0.24	0.10	-400
FOSSIL Gas Primary 100-199	30	0.01	0.01	0.01	0.24	0.10	-400
FOSSIL Gas Primary 200-299	31	0.01	0.01	0.01	0.10	0.22	2273
FOSSIL Gas Primary 300-399	32	0.01	0.01	0.01	0.10	0.22	2273
FOSSIL Gas Primary 400-599	33	0.01	0.01	0.01	0.10	0.22	2273
FOSSIL Gas Primary 600-799	34	0.01	0.01	0.01	0.10	0.22	2273
FOSSIL Gas Primary 800-999	35	0.00	0.01	0.00	0.10	0.22	2273
FOSSIL Lignite Primary All Sizes	37	0.01	0.01	0.01	0.28	0.19	2138
NUCLEAR All Types	38	0.00	0.00	0.00	0.03	0.07	1303
NUCLEAR All Types	39	0.00	0.00	0.00	0.03	0.07	1303
NUCLEAR All Types	40	0.00	0.00	0.00	0.03	0.07	1303
NUCLEAR All Types	41	0.00	0.00	0.00	0.03	0.07	1303
NUCLEAR PWR All Sizes	42	0.00	0.00	0.00	0.03	0.07	1303
NUCLEAR PWR 400-799	43	0.00	0.00	0.00	0.03	0.07	1303
NUCLEAR PWR 800-999	44	0.00	0.00	0.00	0.03	0.07	1303
NUCLEAR PWR 1000 Plus	45	0.00	0.00	0.00	0.03	0.07	1303
NUCLEAR BWR All Sizes	46	0.00	0.00	0.00	0.03	0.07	1303
NUCLEAR BWR 400-799	47	0.00	0.00	0.00	0.03	0.07	1303
NUCLEAR BWR 800-999	48	0.00	0.00	0.00	0.03	0.07	1303
NUCLEAR BWR 1000 Plus	49	0.00	0.00	0.00	0.03	0.07	1303
NUCLEAR CANDU All Sizes	50	0.00	0.00	0.00	0.03	0.07	1303
JET ENGINE All Sizes	51	0.01	0.00	0.00	-0.01	0.11	32
JET ENGINE 001-019	52	0.01	0.00	0.01	-0.13	0.14	1
JET ENGINE 20 Plus	53	0.01	0.00	0.01	-0.15	0.02	0
GAS TURBINE All Sizes	54	0.01	0.00	0.00	-0.01	0.11	32
GAS TURBINE 001-019	55	0.01	0.00	0.01	-0.13	0.14	1
GAS TURBINE 020-049	56	0.01	0.00	0.01	-0.15	0.02	0
GAS TURBINE 50 Plus	57	0.00	0.00	0.00	0.04	0.15	44
COMBINED CYCLE All Sizes	58	0.00	0.00	0.00	0.03	0.00	398
HYDRO All Sizes	59	0.01	0.01	0.00	0.01	0.79	1
HYDRO 001-029	60	0.01	0.01	0.00	0.01	0.79	1
HYDRO 30 Plus	61	0.01	0.01	0.00	0.01	0.79	1
PUMPED STORAGE All Sizes	62	0.00	0.00	0.00	0.53	-0.02	193
MULTIBOILER/MULTI-TURBINE All Sizes	63	0.01	0.00	0.00	-0.01	0.11	32
DIESEL Landfill	64	0.21	0.21	0.20	-0.13	0.60	2
DIESEL All Sizes	65	0.02	0.02	0.03	0.02	0.04	1
FOSSIL Oil/Gas Primary All Sizes	66	0.01	0.01	0.01	0.28	0.19	2138
FOSSIL Oil/Gas Primary 001-099	67	0.01	0.01	0.01	0.24	0.10	-400
FOSSIL Oil/Gas Primary 100-199	68	0.01	0.01	0.01	0.24	0.10	-400
FOSSIL Oil/Gas Primary 200-299	69	0.01	0.01	0.01	0.10	0.22	2273
FOSSIL Oil/Gas Primary 300-399	70	0.01	0.01	0.01	0.10	0.22	2273
FOSSIL Oil/Gas Primary 400-599	71	0.01	0.01	0.01	0.10	0.22	2273
FOSSIL Oil/Gas Primary 600-799	72	0.01	0.01	0.01	0.10	0.22	2273
FOSSIL Oil/Gas Primary 800-999	73	0.00	0.01	0.00	0.10	0.22	2273
Wind All sizes	74	0.00	0.00	0.00	0.00	0.00	0
Solar All sizes	75	0.00	0.00	0.00	0.00	0.00	0

Table II-6: PJM RTO Fleet-based Unit Performance (Non-ELCC Resources)

2027/2028	# of Units	Actual Capacity MW	% Total MW	Forced Outage Rates %	Ambient Temperature Derating (MW)
Combined Cycle	236	64,428	37.9%	3.44%	439
Combustion Turbine	356	25,844	15.2%	5.21%	615
Diesel	86	676	0.4%	10.30%	0
Fossil	169	46,593	27.4%	9.98%	1,450
Nuclear	31	32,539	19.1%	1.03%	0
PJM RTO Total	**878**	**170,079**	**100.00%**	**5.06%**	**2,504**

Figure II-1: PJM RTO Capacity

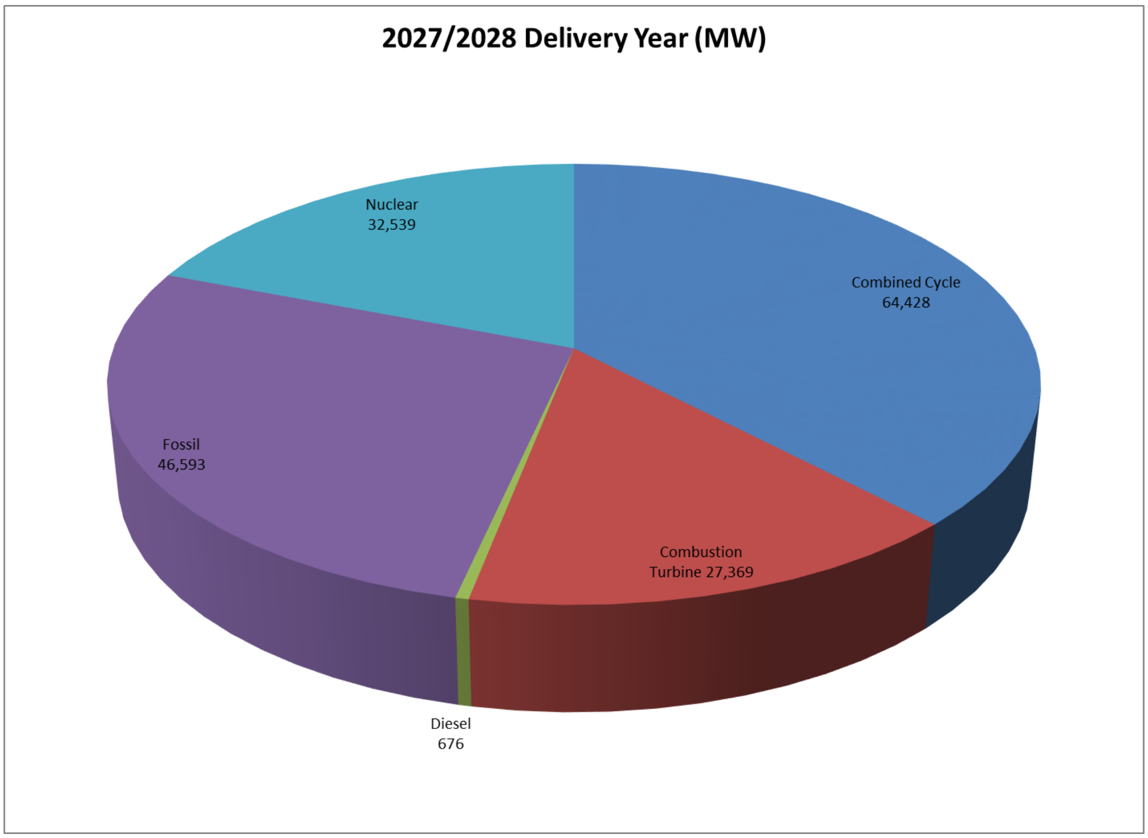


Table II-7: Summary of PJM RTO Existing Wind and Solar resources

Unit Type	# of Units	Nameplate Capacity (MW)	Capacity Value %	Accredited UCAP (MW)
Solar	214	5,567	58.1%	3,234
Wind	95	10,792	14.9%	1,608

Table II-8: New and Retiring Generation within PJM RTO (Non-ELCC Resources)

Zone Name	Total Additions/Changes (MW)	Retirements (MW)	Total
AE	225	132	93
AEP	1,274	0	1,274
APS	1,835	0	1,835
ATSI	850	0	850
BGE	0	1,282	-1,282
ComEd	846	1,100	-254
Dayton	0	0	0
DLCO	0	0	0
DomVP	569	40	529
DPL	0	581	-581
DUKE	0	0	0
JCPL	0	109	-109
METED	0	0	0
PECO	0	0	0
PEPCO	0	0	0
PN	0	0	0
PPL	0	0	0
PSEG	671	0	671
Grand Total	**6,270**	**3,243**	**3,027**

Figure II-2: PJM and Outside World Regions - Capacity Outlook

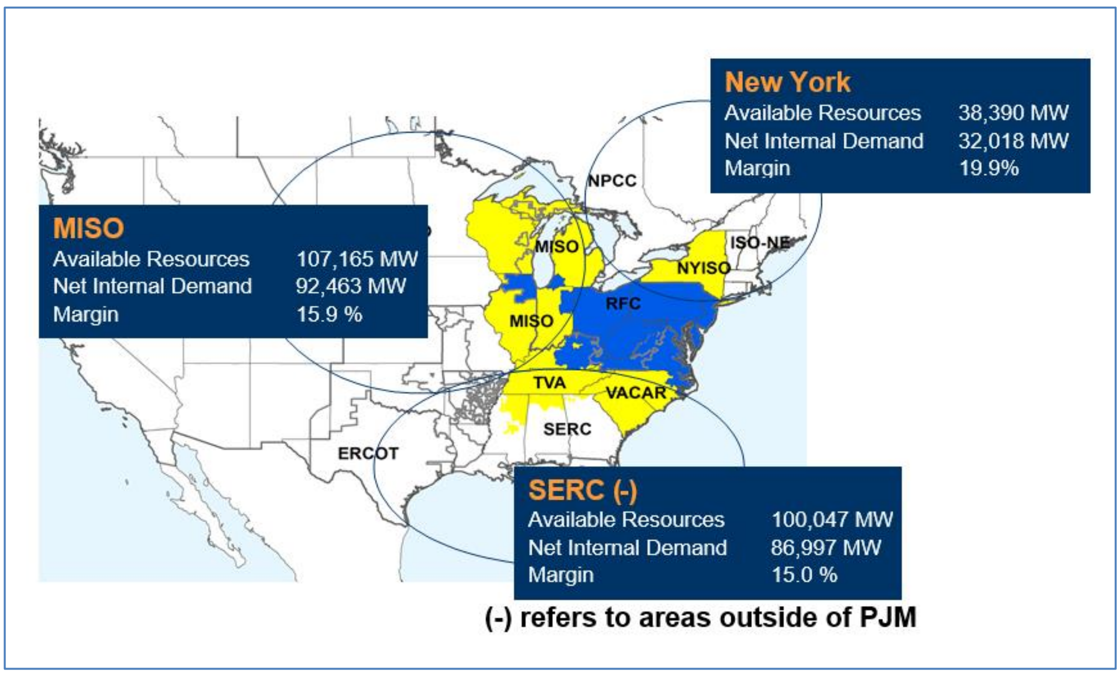


Figure II-3: Summer Expected Weekly Maximum Comparison – PJM – 2023 RRS vs. 2022 RRS

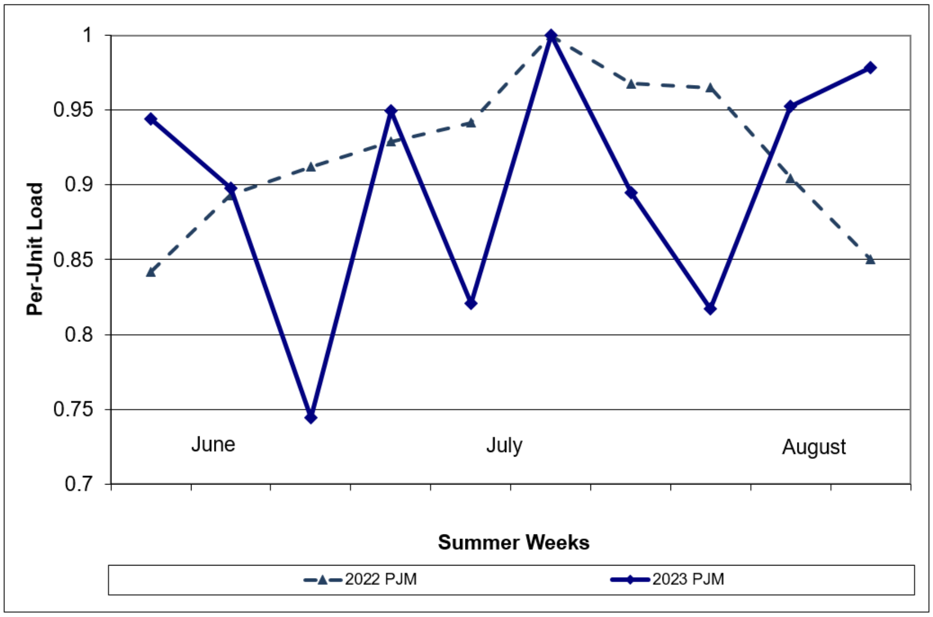


Figure II-4: PJM RTO LOLE Share Comparison 2023 RRS vs. 2022 RRS

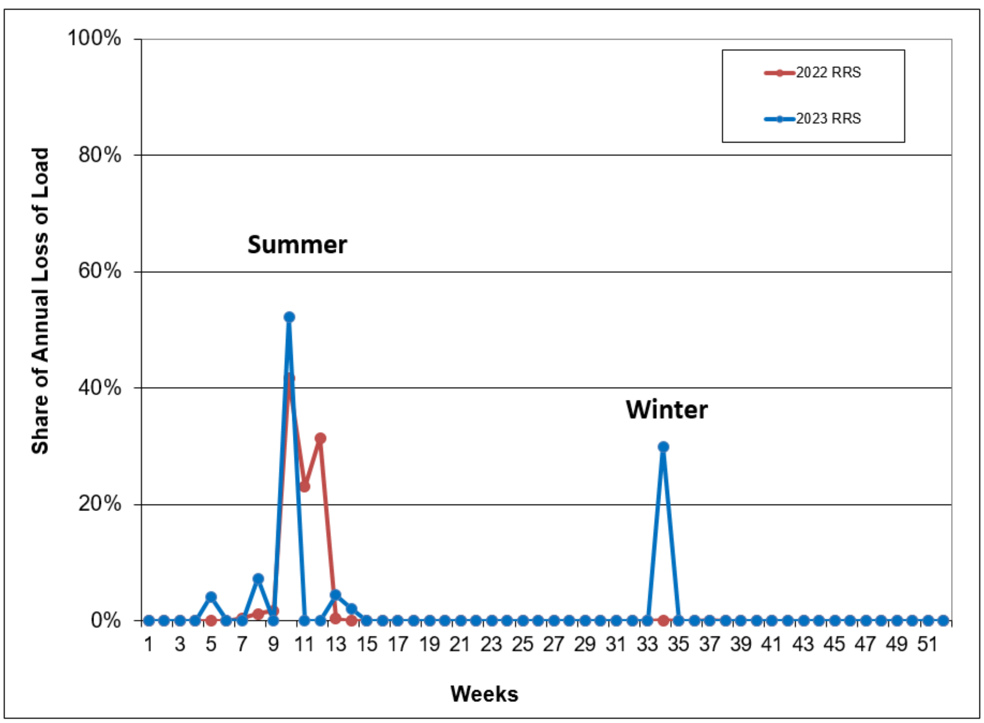
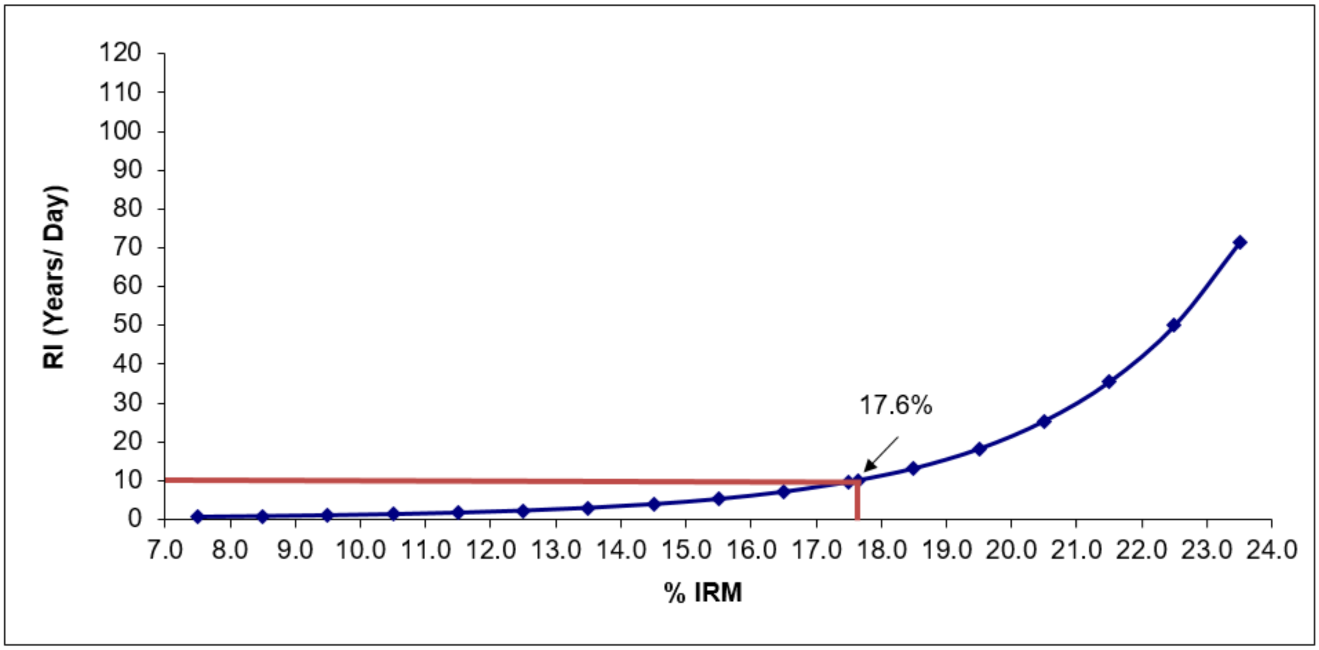
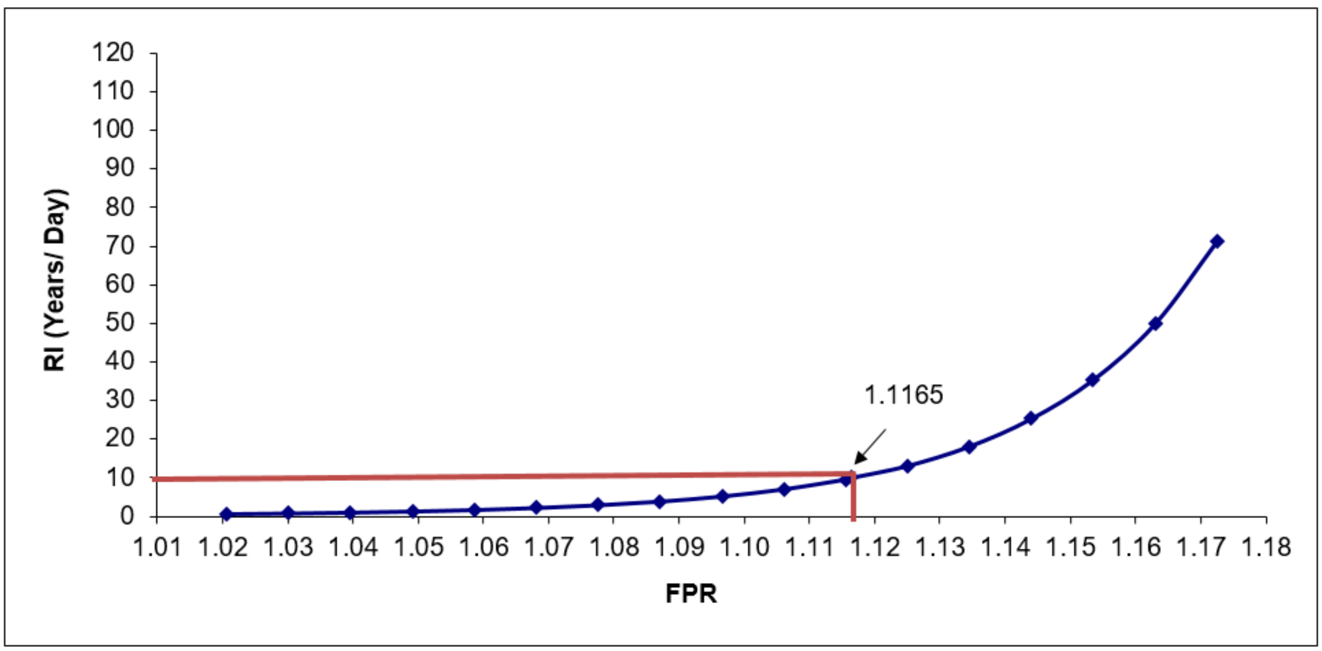


Figure II-5: Installed Reserve Margin (IRM) vs. Reliability Index (Years/Day) and Forecast Pool Requirement (FPR) vs Reliability Index (Years/Day)





Standard BAL-502-RFC-03 clarification items

To provide clarity concerning several items in the Standard BAL-502-RFC-03 requirement section R1 titled “The planning Coordinator shall perform and document a Resource Adequacy analysis annually”, the following is supplied:

R1.3.3.1 The criteria for including planned Transmission facilities: This is given in the RTEP assessments. The RTEP is overseen by the Transmission Expansion Advisory Committee (TEAC), a stakeholder group within the PJM committee structures. The Planning Committee also can establish and recommend appropriate criteria to be used for transmission facilities. See the Transmission System Considerations section for further details. The Criteria for inclusion of planned transmission facilities is given in the meeting minutes and presentations of the TEAC, PC, and the PJM manuals 14 A - E. The RRS is closely coordinated and integrated with these RTEP analyses, and with the decisions by the PC and TEAC as all are parts of the PJM Planning division efforts.

R1.4 Availability and Deliverability of fuel: Generator outages related to the availability and deliverability of fuel are reported by generation owners and stored in the GADS database. These outages are included in the EFORd calculation that is modeled in the RRS. The contribution of these specific outages to the overall generator outage rate is not computed. This is because the RRS models all generator forced outages, regardless of cause.

R1.4 Common Mode Outages that affect resource availability: Fuel availability problems are frequently related to extreme weather and may result in common mode outages. Historical analysis of generator performance over the 15 year period from 2007-2022 indicates that common mode risk is concentrated in the peak weeks of the winter. Therefore, for the peak winter week, which is likely to be the only winter week with loss-of-load risk, the RRS models PJM capacity availability using system-wide aggregate data (as opposed to individual unit data). This practice ensures that common mode outages due to rarely occurring extreme weather are captured in the winter peak week. More detail regarding this practice is included in Manual 20 Section 3.3.

Rare and extremely hot weather in the summer may reduce the output of certain generators due to ambient effects. This risk is considered in the RRS by removing 2,500 MW of available capacity in PJM over the summer months. This procedure is detailed in the Generation Forecasting section, Modeling of Generating Units’ Ambient Deratings subsection in the 2022 RRS.

R1.4 Environmental or regulatory restrictions of resource availability: In the Generation Forecasting section, it is discussed that the resource performance characteristics are primarily modeled per the PJM manuals, 21, 22. In the eGADS reporting, there is consideration and methods to account for both environmental and regulatory restrictions. The RRS modeling of resources uses performance statistics, directly from these reported events. Both discrete modeling techniques and sensitivity analysis are performed to gain insights about impacts concerning environmental or regulatory restrictions. In the modeling of resources this can reduce the rating of a unit impacted by this type of restriction. The RRS model is coordinated with the Capacity Injection Rights (CIR) for each unit, which can be affected by these restrictions.

R1.4 Any other demand response programs not included in the load forecast characteristics: All load modeled and its characteristics are part of R1.3.1, per BAL-502-RFC-03. There are no other load response programs in the RRS model.

R1.4 Market resources not committed to serving load: In general, all resources modeled have capacity injection rights, are part of the EIA-411 filing and coordinated with the RTEP Load deliverability tests, documented in PJM Manual 14 B, attachment C. In addition, coordination with the RPM capacity market modeling is performed.

R1.5 Transmission maintenance outage schedules: Discussed in the Transmission System Considerations section is the coordination with the RTEP process and procedures. This issue is specifically addressed in the load deliverability tests, as discussed in this section. The CETO analysis is closely coordinated with the RRS modeling and report, and is fundamental to addressing and verifying the assumption that the PJM aggregate of generation resources can reliably serve the aggregate of PJM load.

Standard MOD - 004 - 01, requirement 6, clarification items

Capacity Benefit Margin (CBM) is established per the Reliability Assurance Agreement (RAA) section 4 and used in Planning Division studies and assessments. The Regional Transmission Expansion Planning Process (RTEP) provides a 15 year forecast period while the reserve requirement study provides an 11 year forecast period. Each individual year of these periods (15 and 11) are assessed. The RTEP and Reserve Requirement Study (RRS) are performed on an annual basis.

The RTEP and the RRS processes use full network analysis. Available Transmission Capability (ATC) and Flowgate analysis disaggregates the full network model in the short term (daily, weekly, monthly through month 18) as a proxy for full network analysis. The Available Flowgate Capability (AFC) calculator applies the impacts of transmission reservations (or schedules as appropriate) and calculates the AFC by determining the capacity remaining on individual flowgates for further transmission service activity. The disaggregated model used for the AFC calculation provides faster solution time than the full network model. The RTEP assessment is coordinated with the CBM, shown in the RAA, by its use of Capacity Emergency Transfer Objective (CETO) and load forecast modeling. CETO requirements are based on Loss of Load Expectation (LOLE) requiring appropriate aggregation of import paths for a valid statistical model.

Evidence:

- Annual RTEP baseline assessment report http://www.pjm.com/planning/rtep-development/baseline-reports.aspx
- Reliability Assurance Agreement (http://www.pjm.com/documents/~/media/documents/agreements/raa.ashx)
- Annual RRS report(s) http://www.pjm.com/planning/resource-adequacy-planning/reserve-requirement-dev-process.aspx
  - CETO load deliverability studies
  - Section 4, Manual 20 (http://www.pjm.com/~/media/documents/manuals/m20.ashx)
  - Section C.4, Manual 14B (http://www.pjm.com/~/media/documents/manuals/m14b.ashx)
- AFC/ATC calculations, Section 2 and 3 of PJM Manual 2 http://www.pjm.com/~/media/documents/manuals/m02.ashx

IRM and FPR

The Forecast Pool Requirement is the main RPM-related output of the RRS. It represents the amount of Unforced Capacity required above the forecasted 50/50 peak load demand required to meeting the LOLE criteria of 1 day in 10 years. In fact, the PJM RTO Reliability Requirement in RPM is calculated as the FPR times the forecasted 50/50 peak load demand. The Installed Reserve Margin is also an important output of the RRS. However, it does not play a major role in RPM-related markets. Its relevance is limited to compliance with standards from PJM's reliability coordinator, Reliability First.

Procedurally, all inputs into PJM's LOLE software, PRISM, are set up as if the main output of the RRS is the IRM. In particular, the two main parameters required from each generation unit included in the RRS capacity model are: ICAP rating and EEFORd. Once the capacity model and load models have been created, PRISM adjusts the load level until it finds the solution load that meets the one day in ten years reliability standard. The IRM is calculated based on this solution load, for the peak day (which is also the peak week), using the installed capacity for that week in the numerator and the solution load in the denominator.

The FPR is then calculated using the IRM and the PJM RTO pool-wide EFORd as shown in the following equation:

$$\boxed{\textbf{FPR} = (1 + \textbf{Approved IRM}) * (1 - \textbf{PJM Avg. EFORd})}$$

Error! Reference source not found. shows that the IRM and the FPR represent identical levels of reserves expressed in d ifferent units. The IRM is expressed in units of installed capacity (or ICAP) whereas the FPR is expressed in units of unforced capacity (or UCAP). Unforced capacity is defined in the RAA to be the megawatt (MW) level of a generating unit's capability after removing the effect of forced outage events. This definition applies to Unlimited Resources.

Error! Reference source not found. has a few interesting features: the two factors in the equation are dependent, s pecifically the PJM Avg. EFORd is a driver of the Approved IRM value. Furthermore, the two factors are inversely proportional. A larger PJM Avg. EFORd reduces the second term in the equation but will produce a larger Approved IRM, increasing the first term of the equation (and vice versa). In other words, as the second term in the equation decreases, the first term in the equation increases proportionally to the decrease of the second term. The implication of these features is: if the RRS is run using two different portfolio of resources P and P' (with all other inputs in both runs constant), where P' is composed of P plus additional resources Q, the PJM Avg. EFORd of the two runs will likely be different, which will lead to different IRM values, IRM and IRM'. However, the FPR values produced by the two runs will be largely identical. The corollary is that IRM values are very much dependent on the portfolio included in the RRS while FPR value are largely independent of the portfolio included in the RRS.

The following is a stylized example illustrating the concepts described above:

Scenario 1: The RRS is run for a given DY using resource portfolio P. If the resulting IRM is 14.4 while the PJM Avg. EFORd is 5.03%. This yields

$$FPR = (1 + 0.144) \times (1 – 0.0503) = 1.0865$$

Scenario 2: If the same above RRS for a given DY is now run with portfolio P' which is composed of portfolio P plus 5,000 MW ICAP of resources which have an average EFORd of 10% (worse than the 5.03% EFORd of portfolio P), the IRM' will be greater than the IRM because the PJM Avg. EFORd will increase. In fact, the PJM Avg. EFORd will increase to something like 5.19%. This would drive up the IRM' to around 14.6%. Calculating the FPR' yields:

$$FPR' = (1 + 0.146) \times (1 – 0.0519) = 1.0865$$

By comparing Scenario 1 with Scenario 2, it can be seen that two different portfolios produce two different IRM values. However, the FPR remains constant.

One could conceive an alternative version of Scenario 2 in which the resources added to portfolio P are wind and solar resources (or other ELCC Resources) modeled using their nameplate value as ICAP and 1 minus their Capacity Value (in %) as the EFORd-equivalent. If 1 minus their Capacity Value (in %) is greater than 5.03% then the resulting IRM' will be greater than IRM while the FPR' and FPR will be largely identical.

RRS and Effective Load Carrying Capability (ELCC)

The Effective Load Carrying Capability (ELCC) study calculates the capacity value of Variable, Limited and Combination Resources. These three resource categories are designated as ELCC Resources (Unlimited Resources, on the other hand, are not ELCC Resources and their capacity values are calculated using the regular UCAP formula). In addition, the following ELCC-related terms have been introduced (other ELCC-related terms have been added to the Glossary):

Effective UCAP is a unit of measure that represents the resource adequacy value exchanged in the Capacity Market. One megawatt of Effective UCAP has the same resource adequacy value of one megawatt of Unforced Capacity (UCAP).

Accredited UCAP as denominated in Effective UCAP shall mean the quantity of Unforced Capacity that an ELCC Resource is capable of providing in a given Delivery Year.

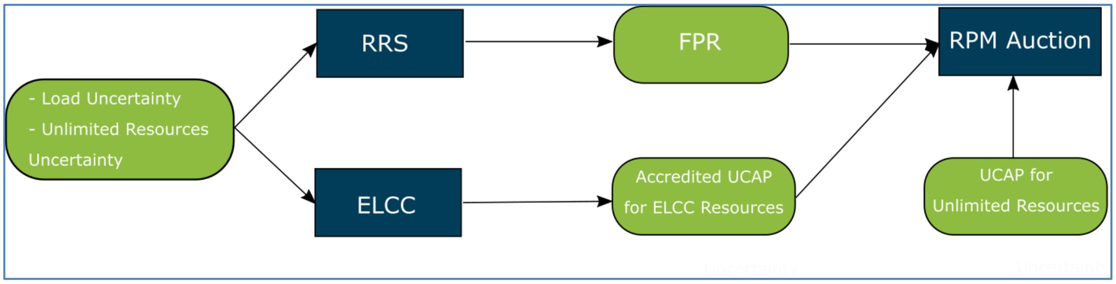
ELCC Portfolio UCAP shall mean the aggregate Effective UCAP that all ELCC Resources are capable of providing in a given Delivery Year.

ELCC Class UCAP shall mean the aggregate Effective UCAP all ELCC Resources in a given ELCC Class are capable of providing in a given Delivery Year.

ELCC Class Rating shall mean the rating factor, based on effective load carrying capability analysis that applies to ELCC Resources that are members of an ELCC Class as part of the calculation of their Accredited UCAP.

The relationship between the ELCC study and the RRS is depicted in Figure II-6.

Figure II-6: RRS and ELCC Relationship



There are two main common inputs into the ELCC and the RRS studies: load uncertainty (the load model in the RRS) and unlimited resources uncertainty (the capacity model in the RRS). Currently, the inputs into the two studies are not identical (mainly because the ELCC model is hourly while the RRS looks at daily peaks only), however, the key data sources are the same: for load uncertainty, the source is the PJM Load Forecast; for unlimited resources uncertainty, the source is GADS. This provides consistency in the way the two studies are run.

For market-related purposes, the main output of the RRS is the FPR which is then used to set up the reliability requirement (and the demand curve) for RPM Auctions. Resources compete to meet this reliability requirement using the Accredited UCAP values from the ELCC study (in the case of ELCC Resources) and the UCAP values calculated using GADS data (in the case of Unlimited Resources).

Operations Related Assessments

Winter Weekly Reserve Target Analysis

PJM calculates a Winter Weekly Reserve Target (WWRT) for each of the months in the 2023 / 2024 winter period (December 2023, January 2024 and February 2024). The WWRT is established to cover against uncertainties associated with load and forced outages during these winter months. It accomplishes this by ensuring that the total winter LOLE is practically zero. This year, PJM Staff recommends the values shown in Table II-9. The recommended values are required to be integers due to computer application requirements.

Table II-9: Winter Weekly Reserve Target

Month	WWRT
December 2023	28%
January 2024	30%
February 2024	25%

The procedure implemented to calculate the values in Table II-9 considers the following steps:

Step 1: Set up an RRS case with an annual LOLE equal to 0.1 days/year.

Step 2: In addition to the required planned maintenance schedule, simulate additional planned maintenance during each week of the three winter months until the annual LOLE is worse than 0.1 days/year.

Step 3: Calculate the available reserves in each of the winter weeks as a percentage of the corresponding monthly peak.

Step 4: The WWRT for each month is the highest weekly reserve percentage (rounded up to the next integer value).

Table II-10 shows the weekly available reserves that result from applying the above procedure.

Table II-10: Weekly Available Reserves in WWRT Analysis

Month	% Available Reserves	WWRT (Max Monthly % Available Reserves)
December	14.78%	28%
	27.23%	
	8.97%	
	12.70%	
January	29.77%	30%
	4.37%	
	21.08%	
	24.43%	
February	19.39%	25%
	24.50%	
	23.24%	
	17.62%	

Monthly WWRT values were introduced for the first time in the 2016 RRS with the objective of addressing the larger load uncertainty in January compared to February and December. Prior to the 2016 RRS, the WWRT was a single value that applied to the entire winter season. Historically, January is the month where the PJM Winter peak is most likely to occur and also the winter month that has exhibited more peak load variability.

With this recommendation, the PJM Operations Department will coordinate generator maintenance scheduling over the winter period seeking to preserve a 28% margin in December 2023, 30% margin in January 2024 and 25% margin in February 2024 after units on planned and maintenance outages are removed**.** These margins are guides to be used by PJM Operations and are not an absolute requirement.

III. Appendices

Appendix A
Base Case Modeling Assumptions for 2023 PJM RRS

Parameter	2022 Study Modeling Assumptions	2023 Study Modeling Assumptions Set #1	2023 Study Modeling Assumptions Set #2	Basis for Assumptions
Load Forecast				
Unrestricted Peak Load Forecast	152,259 MW (2026/2027 DY)	154,275 MW (2027/2028 DY)	Same as Set #1	Forecasted Load growth per 2023 PJM Load Forecast Report, using 50/50 normalized peak.
Historical Basis for Load Model	2002-2012	2013-2019	Not Applicable	Set #1: Load model selection method approved at the June 6, 2023 PC meeting (see Attachment V). Set #2: Load model reflects peak load uncertainty in the most recent PJM Load Forecast
Forecast Error Factor (FEF)	Forecast Error held at 1 % for all delivery years.	Forecast Error held at 1 % for all delivery years.	Not Applicable	Set #1: Consistent with consensus gained through PJM stakeholder process. Set #2: FEF is not modeled. Model reflects peak load uncertainty in the most recent PJM Load Forecast
Monthly Load Forecast Shape	Consistent with 2022 PJM Load Forecast Report and 2020 NERC ES&D report (World area).	Consistent with 2022 PJM Load Forecast Report and 2020 NERC ES&D report (World area).	Not Applicable	Set #1: Updated data. Set #2: Model reflects monthly peak load uncertainty in the most recent PJM Load Forecast
Daily Load Forecast Shape	Standard Normal distribution and Expected Weekly Maximum (EWM) based on 5 daily peaks in week.	Standard Normal distribution and Expected Weekly Maximum (EWM) based on 5 daily peaks in week.	From each Delivery Year in period DY 2012- DY 2021	Set #1: Consistent with consensus gained through PJM stakeholder process. Set#2: ELCC model uses load shapes for period DY 2012 – DY 2021

Parameter	2022 Study Modeling Assumptions	2023 Study Modeling Assumptions Set #1	2023 Study Modeling Assumptions Set #2	Basis for Assumptions
Capacity Forecast				
Generating Unit Capacities	Coordinated with eRPM databases, EIA-411 submission, and Generation Owner review.	Coordinated with eRPM databases, EIA-411 submission, and Generation Owner review.	Same as Set #1	New RPM Market structure required coordination to new database Schema. Consistency with other PJM reporting and systems.
New Units	Generation projects in the PJM interconnection queue with a signed Interconnection Service Agreement (ISA) will be modeled in the PJM RTO at their capacity MW value.	Generation projects in the PJM interconnection queue with a signed Interconnection Service Agreement (ISA) will be modeled in the PJM RTO at their capacity MW value.	Same as Set #1	Consistent with CETO cases.
ELCC Resources (Variable, Limited-Duration, Combination Resources)	All variable (wind, solar, hydro, landfill gas) and storage-type resources (pumped hydro, batteries, hybrids, and generic limited-duration resources) will be excluded from the RRS.	All variable (wind, solar, hydro, landfill gas) and storage-type resources (pumped hydro, batteries, hybrids, and generic limited-duration resources) will be excluded from the RRS.	Same as Set #1	The capacity value of ELCC resources will be calculated with the ELCC model, which is largely consistent with the RRS.
Firm Purchases and Sales	Firm purchase and sales from and to external regions are reflected in the capacity model. External purchases reduce the World capacity and increase the PJM RTO capacity. External Sales reduce the PJM RTO capacity and increase the World capacity. This is consistent with EIA-411 Schedule 4 and reflected in RPM auctions.	Firm purchase and sales from and to external regions are reflected in the capacity model. External purchases reduce the World capacity and increase the PJM RTO capacity. External Sales reduce the PJM RTO capacity and increase the World capacity. This is consistent with EIA-411 Schedule 4 and reflected in RPM auctions.	Same as Set #1	Match EIA-411 submission and RPM auctions.
Retirements	Coordinated with PJM Operations, Transmission Planning models and PJM web site: **http://www.pjm.com/planning/generation-retirements.aspx** . Consistent with forecast reserve margin graph.	Coordinated with PJM Operations, Transmission Planning models and PJM web site: **https://pjm.com/planning/services-requests/gen-deactivations**. Consistent with forecast reserve margin graph.	Same as Set #1	Updated data available on PJM's web site, but model data frozen in May 2023.
Planned and Operating Treatment of Generation	All generators that have been demonstrated to be deliverable will be modeled as PJM capacity resources in the PJM study area. External capacity resources will be modeled as internal to PJM if they meet the following requirements: 1.Firm Transmission service to the PJM border	All generators (other than ELCC resources) that have been demonstrated to be deliverable will be modeled as PJM capacity resources in the PJM study area. External capacity resources will be modeled as internal to PJM if they meet the following requirements:	Same as Set #1	Consistency with other PJM reporting and systems.

Parameter	2022 Study Modeling Assumptions	2023 Study Modeling Assumptions Set #1	2023 Study Modeling Assumptions Set #2	Basis for Assumptions
	2.Firm ATC reservation into PJM 3.Letter of non-recallability from the native control zone Assuming that these requirements are fully satisfied, the following comments apply: •Only PJM's "owned" share of generation will be modeled in PJM. Any generation located within PJM that serves World load with a firm commitment will be modeled in the World. •Firm capacity purchases will be modeled as generation located within PJM. Firm capacity sales will be modeled by decreasing PJM generation by the full amount of the sale. •Non-firm sales and purchases will not be modeled. The general rule is that any generation that is recallable by another control area does not qualify as PJM capacity and therefore will not be modeled in the PJM Area. •Generation projects in the PJM interconnection queue with a signed Interconnection Service Agreement (ISA) will be modeled in the PJM RTO at their capacity MW value.	1.Firm Transmission service to the PJM border 2.Firm ATC reservation into PJM 3.Letter of non-recallability from the native control zone Assuming that these requirements are fully satisfied, the following comments apply: •Only PJM's "owned" share of generation will be modeled in PJM. Any generation located within PJM that serves World load with a firm commitment will be modeled in the World. •Firm capacity purchases will be modeled as generation located within PJM. Firm capacity sales will be modeled by decreasing PJM generation by the full amount of the sale. •Non-firm sales and purchases will not be modeled. The general rule is that any generation that is recallable by another control area does not qualify as PJM capacity and therefore will not be modeled in the PJM Area. •Generation projects in the PJM interconnection queue with a signed Interconnection Service Agreement (ISA) will be modeled in the PJM RTO at their capacity MW value.		

Unit Operational Factors				
Forced and Partial Outage Rates	5-year (2017-21) GADS data. (Those units with less than five years data will use class average representative data.).	5-year (2018-22) GADS data. (Those units with less than five years data will use class average representative data.).	5-year (2018-22) GADS data. (Those units with less than five years data will use class average representative data.). In addition, Mean Time to Failure (MTF) and Mean Time to Repair (MTR) are estimated for each unit consistent with the 2018-2022 period	Set #1: Most recent 5-year period. Use PJM RTO unit fleet to form class average values. Set #2: Most recent 5-year period. Use PJM RTO unit fleet to form class average values. Hourly model requires MTF and MTR metrics
Planned Outages	Based on eGADS data, History of Planned Outage Factor for units.	Based on eGADS data, History of Planned Outage Factor for units.	Same as Set #1	Updated schedules.
Summer Planned Outage Maintenance	In review of recent Summer periods, no Planned outages have occurred.	In review of recent Summer periods, no Planned outages have occurred.	Same as Set #1	Review of historic 2018 to 2022 unit operational data for PJM RTO footprint.
Gas Turbines, Fossil, Nuclear Ambient Derate	Ambient Derate includes several categories of units. Based on analysis of the Summer Verification Test data from the last 3 summers, 2,500 MW out on planned outage over summer peak was confirmed to be the best value to use at this time. This analysis was performed early 2016 under the auspices of the RAAS.	Ambient Derate includes several categories of units. Based on analysis of the Summer Verification Test data from the last 3 summers, 2,500 MW out on planned outage over summer peak was confirmed to be the best value to use at this time. This analysis was performed early 2016 under the auspices of the RAAS.	Same as Set #1	Operational history and Operations Staff experience indicates unit derates during extreme ambient conditions. Summer Verification Test data confirms this hypothesis.
Generator Performance	For each week of the year, except the winter peak week, the PRISM model uses each generating unit's capacity, forced outage rate, and planned maintenance outages to develop a cumulative capacity outage probability table. For the winter peak week, the cumulative capacity outage probability table is created using historical actual (DY 2007/08 – DY 2021/22) RTO-aggregate outage data (data from DY 2013/14 will be dropped and replaced with data from DY 2014/15).	For each week of the year, except the winter peak week, the PRISM model uses each generating unit's capacity, forced outage rate, and planned maintenance outages to develop a cumulative capacity outage probability table. For the winter peak week, the cumulative capacity outage probability table is created using historical actual (DY 2007/08 – DY 2022/23) RTO-aggregate outage data.	Same as Set #1	New methodology to develop winter peak week capacity model to better account for the risk caused by the large volume of concurrent outages observed historically during the winter peak week.
Class Average Statistics	PJM RTO fleet Class Average values. 73 categories based on unit type, size and primary fuel.	PJM RTO fleet Class Average values. 73 categories based on unit type, size and primary fuel.	Same as Set #1	PJM RTO values have a sufficient population of data for most of the categories. The values are more consistent with planning experience.

Uncommitted Resources	Behind the meter generation (BTMG) is not included in the capacity model because such resources cannot be capacity resources. The impact of behind the meter generation (BTMG) is reflected on the load side.	Behind the meter generation (BTMG) is not included in the capacity model because such resources cannot be capacity resources. The impact of behind the meter generation (BTMG) is reflected on the load side.	Same as Set #1	Consistency with other PJM reporting and systems.
Generation Owner Review	Generation Owner review and sign-off of capacity model.	Generation Owner review and sign-off of capacity model.	Same as Set #1	Annual review to insure data integrity of principal modeling parameters.
Load Management and Energy Efficiency				
Load Management and Energy Efficiency	**PJM RTO load management modeled per the January 2022 PJM Load Forecast Report (Table B7)**	PJM RTO load management modeled per the January 2023 PJM Load Forecast Report (Table B7)	Same as Set #1	Model latest load management and energy efficiency data. Based on Manual 19, Section 3 for PJM Load Forecast Model.
Emergency Operating Procedures	IRM reported for Emergency Operating Procedures that include invoking load management but before invoking Voltage reductions.	IRM reported for Emergency Operating Procedures that include invoking load management but before invoking Voltage reductions.	Same as Set #1	Consistent reporting across historic values.
Transmission System				
Interface Limits	The Capacity Benefit Margin (CBM) is an input value used to reflect the amount of transmission import capability reserved to reduce the IRM. This value is 3,500 MW.	The Capacity Benefit Margin (CBM) is an input value used to reflect the amount of transmission import capability reserved to reduce the IRM. This value is 3,500 MW. See main assumptions document for CBOT calculation.	Not Applicable. See main assumptions document for CBOT calculation.	Set #1: Reliability Assurance Agreement, Schedule 4, Capacity Benefit Margin definition. Set #2: Model only includes PJM region

Appendix B

Comparison between 2023 RRS Results using PRISM and Hourly Loss of Load Model

The objective of this appendix is to provide an overview of the results produced by the two software tools, PRISM and the Hourly Loss of Load Model and PJM's rationale underlying the recommendation to use the PRISM results as the 2023 RRS results.

The two sets of results are shown in Tables III-1 and III-2. Table III-1 shows the IRM and FPR values produced by PRISM while Table III-2 shows the values produced by the Hourly Loss of Load Model. Note that the IRM and FPR values in both tables incorporate the impact of the CBOT calculation.

Table III-1: 2023 Reserve Requirement Study Summary Table - PRISM

RRS Year	Delivery Year Period	Recommended IRM	Average EFORd	Recommended FPR
2023	2024 / 2025	**17.7%**	5.10%	**1.1170**
2023	2025 / 2026	**17.7%**	5.09%	**1.1171**
2023	2026 / 2027	**17.7%**	5.08%	**1.1172**
2023	2027 / 2028	**17.6%**	5.06%	**1.1165**

Table III-2: 2023 Reserve Requirement Study Summary Table – Hourly Loss of Load Model

RRS Year	Delivery Year Period	Recommended IRM	Average EFORd	Recommended FPR
2023	2024 / 2025	**18.5%**	5.10%	**1.1246**
2023	2025 / 2026	**18.4%**	5.09%	**1.1237**
2023	2026 / 2027	**18.4%**	5.08%	**1.1239**
2023	2027 / 2028	**18.3%**	5.06%	**1.1231**

The IRM and FPR values produced by the Hourly Loss of Load Model are consistently higher than those produced by PRISM. Three of the four main drivers for the IRM and FPR results, the Capacity Model (non winter peak week), the Capacity Model (winter peak week) and the CBOT are modeled similarly (identically, in the case of the CBOT impact) in both software tools. Therefore, the main source for the difference in the IRM and FPR values between the two tools is the Load Model. In addition, the main driver for the calculation of the FPR is the Load Model.

PRISM's Load Model uses a normal distribution to model the daily peak load uncertainty of each weekday in a week. A total of 52 normal distributions are estimated by using historical load data from a historical time period selected using the Load Model Selection process. The main driver for the Load Model Selection process is that the uncertainty modeled in the annual peak week's normal distribution estimated with load data from the historical time period must be a good match of the annual peak load uncertainty modeled in the PJM Load Forecast. For the 2023 RRS, PJM recommended the historical time period 2013-2019.

The Hourly Loss of Load Model considers 1,000 hourly load scenarios (each scenario includes 8,760 hours) associated with each of the load shapes since delivery year 2012. Therefore, a total of 10,000 scenarios were considered in the 2023 RRS (10 delivery years between 2012 and 2021 times the 1,000 scenarios). The 10,000 scenarios are intended to cover the entire monthly peak load uncertainty included in the PJM Load Forecast. More details on the load model used in the Hourly Loss of Load Model are available on Section 5.2 of PJM Manual 20. The key element in the approach to derive the 10,000 scenarios is the use of a multivariate normal distribution to generate variability around the monthly peaks. The parameters (mean and covariance matrix) for the multivariate normal distribution are derived using the set of monthly peaks for the 377 weather scenarios included in the 2023 PJM Load Forecast.

Since the goal of the load models used in PRISM and the Hourly Loss of Load Model is to represent the load uncertainty included in the PJM Load Forecast, PJM calculated the 2027/28 IRM and FPR using the daily peak distributions from the PJM Load Forecast and compared the values to those produced by PRISM and the Hourly Loss of Load Model. The results of the comparison are in Table III-3.

Table III-3: 2027/28 FPR and IRM Comparison of load models and software tools

Load Model	2027/28 FPR	2027/28 IRM	FPR Difference Relative to PJM Load Forecast	IRM Difference Relative to PJM Load Forecast
PJM Load Forecast	1.1193	17.9%	-	-
PRISM	1.1165	17.6%	-0.0028	-0.3%
Hourly Loss of Load	1.1231	18.3%	0.0038	0.4%

The values produced by PRISM are closer to the values produced using the daily peak distributions from the PJM Load Forecast than the values produced with the Hourly Loss of Load Model. This is because the Hourly Loss of Load Model includes load uncertainty, via the multivariate normal distribution, that goes beyond that included in the daily peak distributions from the PJM Load Forecast. PJM is therefore recommending to use the IRM and FPR values produced by PRISM.

Appendix C
2023 Study Sensitivity Cases

1	**CP 1 Distribution – 2022 LF vs 2023 LF**	
	This sensitivity was performed by replacing the CP distributions from the 2023 LF with those from the 2022 LF. Note that this was not run in PRISM, using a single area case. The Single Area IRM decreased by 2.2 percentage points.	
2	**Removing January 2014 outage data from the Winter Peak Week thermal availability distribution**	
	This sensitivity was run using a single area case. The Single Area IRM decreased by 0.5 percentage points.	
3	**Forecast Error Factor**	
	This sensitivity was run using a single area case. Reducing the Forecast Error Factor to 0% (from 1%) in PRISM decreased the Single Area IRM by 0.17 percentage points.	
4	**Single Area Case**	
	The Single Area IRM was decreased by a CBOT of 1.5 percentage points. Therefore, assuming the RTO without emergency assistance increased the IRM by 1.5 percentage points.	