

2026 PJM Effective Load Carrying Capability and Reserve Requirement Study (ELCC/RRS)

For Public Use

PJM Resource Adequacy Planning

October 30, 2026

This page is intentionally left blank

Contents

Executive Summary 5

Introduction 12

Purpose 12

Regional Modeling 12

Summary of RRS Results 13

Eleven-Year RRS Results 13

Recommendations 15

Model Overview 16

General Overview 16

IRM Subprocess 17

Inputs 17

LOLP Model 29

Capacity Benefit of Ties (CBOT) 37

IRM Calculation 37

Accreditation Subprocess 38

LOLP Model and ELCC Class Ratings and Resource-Specific ELCC Values 38

ELCC Resource Performance Adjustment 40

Accredited UCAP and Accredited UCAP Factor 41

FPR Subprocess 42

FPR Calculation 42

Discussion of Results 43

Delivery Years 2028/2029 and 2029/2030 43

Delivery Years 2030/2031 Through 2042/2043 60

Appendix I: Pseudo-code 77

Appendix II: Indicative ELCC Values for ELCC Classes with No Class Rating 80

Appendix III: Indicative ELCC Values for Longer Duration Storage **81**

Appendix IV: Sensitivities **82**

Constant Large Load Additions 82

Excluding Load Scenarios derived with data from Weather Year 1993/1994 83

2027/2028 Base Residual Auction (BRA) Cleared Resource Mix 85

2028/2029 Base Residual Auction (BRA) Cleared Resource Mix 86

Appendix V: Supplemental Graphs Comparing the 2028/2029 BRA and 2029/2030 BRA runs **88**

Appendix VI: Acronyms **90**

Executive Summary

- The PJM Effective Load Carrying Capability and Reserve Requirement Study (ELCC/RRS) provides information about resource adequacy parameters, such as the Installed Reserve Margin (IRM), Forecast Pool Requirement (FPR) and ELCC Class Ratings for future Delivery Years (DY). In accordance with the Reliability Pricing Model (RPM) auction schedule, this study includes parameters to be used in the Base Residual Auction (BRA) for the 2028/2029 DY and 2029/2030 DY. In addition, parameters for DYs other than these two DYs are also included for informational purposes only.

- PJM publishes this report to satisfy the North American 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 uses a Loss of Load Expectation (LOLE) of one occurrence in ten years.

- PJM calculated the values included in this report using its own resource adequacy software tool. The tool simulates supply and demand in the RTO area on an hourly basis, without internal transmission constraints. For more details on the tool, see the Model Overview section and the video tutorials.

- The PJM RTO includes the PJM Mid-Atlantic Region, Allegheny Power (APS), American Electric Power (AEP), Commonwealth Edison (ComEd), Dayton Power and Light Company (Dayton), Virginia Electric and Power Company (Dominion), Duquesne Light Company (DLCO), American Transmission Systems, Incorporated (ATSI), Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc. (DEOK), East Kentucky Power Cooperative, Inc. (EKPC) and Ohio Valley Electric Corporation (OVEC).The Capacity Benefit of Ties (CBOT) was administratively set at 1.5% for all DYs, the same value that has been used in the most recent planning parameter calculations.

- PJM staff recommends, and the PJM Board approved, FPR values equal to **0.9401 for the 2028/2029 Delivery Year and 0.9232 for the 2029/2030 Delivery Year**. These FPR values are a key parameter for the Reliability Requirement calculation in RPM.

- The IRM values associated with the above FPR values are 20.0% for the 2028/2029 Delivery Year and 20.4% for the 2029/2030 Delivery Year.

- The main input/assumption changes between the 2025 ELCC/RRS and the 2026 ELCC/RRS are:

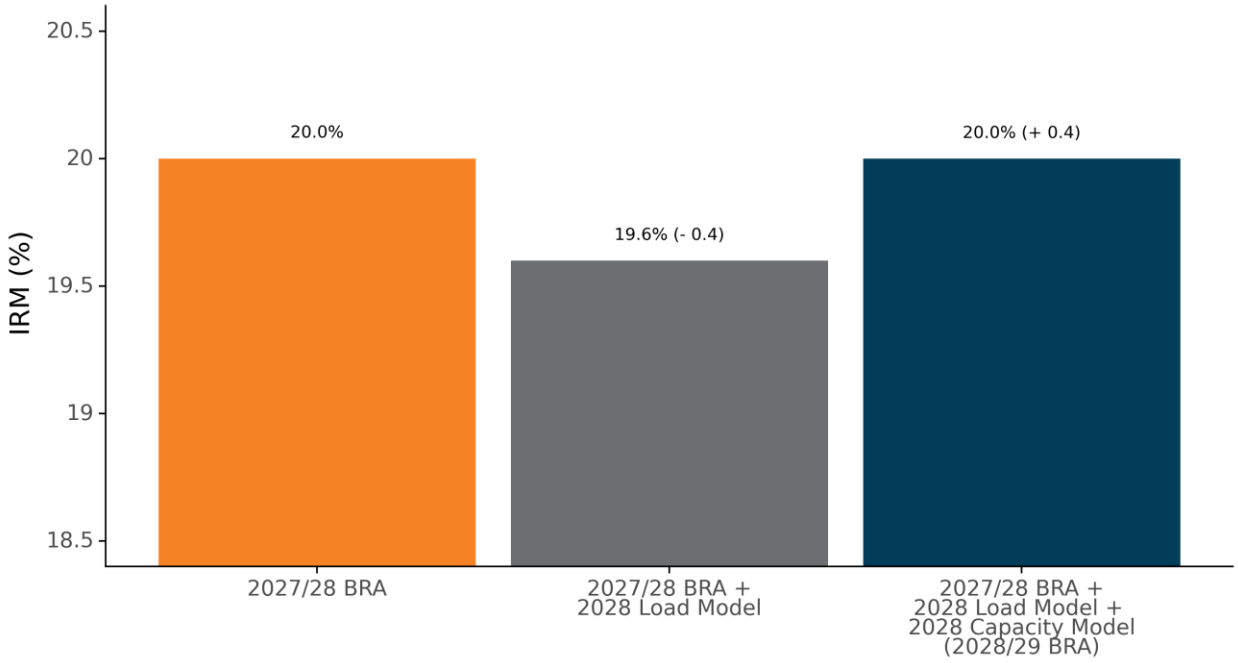
  - The hourly load shapes used in the calculations in the 2026 ELCC/RRS are based on the 2026 PJM Load Forecast while those in the 2025 ELCC/RRS are based on the 2025 PJM Load Forecast

  - The historical resource performance used in the calculations in the 2026 ELCC/RRS is from the period June 1, 2012 through May 31, 2025 whereas that in the 2025 ELCC/RRS is from the period June 1, 2012 through May 31, 2024.

  - The resource portfolios used in the calculations in the 2026 ELCC/RRS for each of the target DYs are different from the resource portfolios used in the 2025 ELCC/RRS as RPM-related information (such as Notice of Intent to offer into auctions) was updated and the vendor-supplied forecast of additions and retirements was also updated.

- The 20.0% IRM for 2028/2029 in the 2026 ELCC/RRS is the same value as the IRM calculated in the 2025 ELCC/RRS for 2027/2028. The constant value in the IRM can be explained as a function of the above input/assumption changes as shown in **Figure 1**, which illustrates the impact of adding the changes one by one. While the quantification of each individual impact depends on the order of quantifying impacts, the total aggregate impact (+0.0%) does not.

Figure 1. Impact on IRM due to changes from 2027/2028 BRA to 2028/2029 BRA

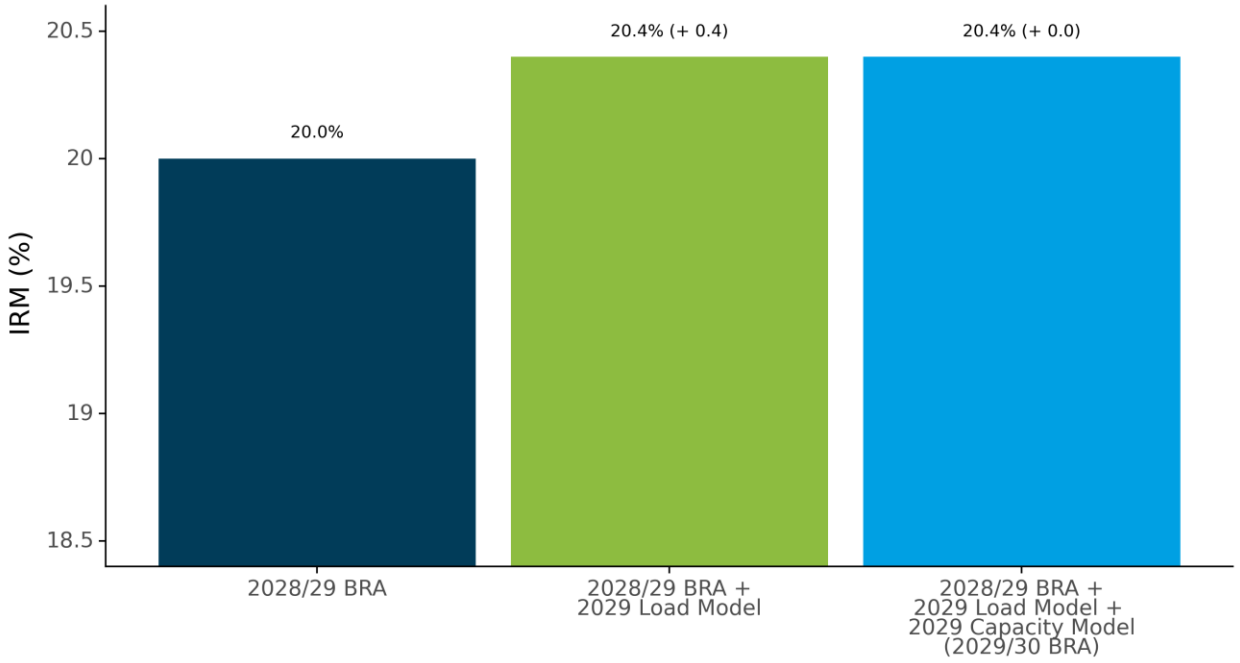


- Adding the 2028 Load Model to the 2027/2028 BRA run decreases the IRM by 0.4 percentage points (dark grey bar labeled "2027/28 BRA + 2028 Load Model" in Error! Reference source not found.). This occurs because the hourly load shapes for 2028/2029 (derived from the 2026 PJM Load Forecast) include lower extreme winter loads (as a share of the 2028/2029 forecasted annual median peak) than the hourly shapes for 2027/2028 (derived from the 2025 PJM Load Forecast).

- The cumulative addition of the 2028/2029 Capacity Model to the previous run results in an increase to the IRM of about 0.4 percentage point (dark blue bar labeled "2027/28 BRA + 2028 Load Model + 2028 Capacity Model (2028/29 BRA)" in Error! Reference source not found.; this is the 2028/2029 BRA run). This occurs because, compared to the 2027/2028 Capacity Model, the 2028/2029 Capacity Model excludes announced deactivations from resources with relatively high accreditation (coal and gas) while the additions are from resources with relatively low accreditation (solar and 4-hr storage). Overall, this means that the 2028/2029 Capacity Model requires more total ICAP than the 2027/2028 Capacity Model to serve the same peak load levels.

- The 20.4% IRM for 2029/2030 in the 2026 ELCC/RRS represents an increase of 0.4 percentage points relative to the 2028/2029 IRM calculated in the 2026 ELCC/RRS. The increase in the IRM value can be explained as a function of the input/assumption changes in **Figure 2**, which illustrates the impact of adding the changes one by one.

Figure 2. Impact on IRM due to changes from 2028/2029 BRA to 2029/2030 BRA



- Adding the 2029 Load Model to the 2028/2029 BRA run increases the IRM by 0.4 percentage points (green bar labeled "2028/29 BRA + 2029 Load Model" in **Figure 2**). This occurs because the hourly load shapes for 2029/2030 (derived from the 2026 PJM Load Forecast) include higher extreme winter loads (as a share of the 2029/2030 forecasted annual median peak) than the hourly shapes for 2028/2029 (also derived from the 2026 PJM Load Forecast).

- The cumulative addition of the 2029/2030 Capacity Model to the previous run keeps the IRM constant (light blue bar in **Figure 2**; this is the 2029/2030 BRA run). This occurs because the 2029/2030 Capacity Model, compared to the 2028/2029 Capacity Model, includes ICAP increases in Unlimited Resources classes (mainly the gas classes) via planned generation and withdrawn deactivations as well as ICAP increases in the Tracking Solar Class. While additions of mainly solar tracking resources put upward pressure on the 2029/2030 IRM, the significant addition of Unlimited Resources offsets the solar tracking addition impact, leaving the overall impact of the 2029/2030 Capacity Model on the 2029/2030 IRM at a negligible level.

- The 0.9401 FPR for 2028/2029 represents an increase of 0.0141 relative to the FPR calculated for 2027/2028 (0.9260). Changes in the FPR value cannot be interpreted in isolation and should be analyzed in conjunction with changes in the overall accreditation of the resource mix. This is because the FPR is used to determine total amount of Accredited UCAP (AUCAP) required by the system, and it can be the case that the FPR increases simply because the accreditation of the resource mix increases. In other words, an increased FPR does not necessarily mean the supply/demand balance in the system is tighter if Total Accredited UCAP is increasing commensurately. Therefore, to assess the impact of the input/assumption changes in the 2028/2029 values, **Table 1** provides the values for the FPR, Pool-wide average Accredited UCAP Factor, illustrative 2028/2029 Reliability Requirement, illustrative 2028/2029 total Accredited UCAP (AUCAP), and illustrative 2028/2029 BRA supply/demand tightness for each of the same three runs used to explain the change in IRM above.

Table 1. Additional Impacts due to changes from 2027/2028 BRA to 2028/2029 BRA

	2027/2028 BRA	2027/2028 BRA + 2028/2029 Load Model	2027/2028 BRA + 2028/2029 Load Model + 2028/2029 Capacity Model (2028/2029 BRA)
FPR	0.9260	1.0222 (+0.0962)	0.9401 (-0.0821)
Pool-wide average UCAP Factor	0.7717	0.8547 (+0.0830)	0.7834 (-0.0713)
Illustrative 2028/2029 BRA Total AUCAP (MW)*	151,925	168,266 (+16,340)	154,229 (-14,037)
Illustrative 2028/2029 BRA Reliability Requirement (MW)**	153,315	169,243 (+15,928)	155,650 (-13,593)
Illustrative 2028/2029 BRA Supply/Demand Tightness (MW) ***	-1,390	-977 (+413)	-1,421 (-443)

* Calculated as Total ICAP in 2028/2029 Run (196,871 MW) times Pool-wide average UCAP Factor row

** Calculated as 2028/2029 Forecasted Peak Load (165,567 MW) times FPR row

*** Calculated as Illustrative 2028/2029 BRA Total AUCAP row minus Illustrative 2028/2029 BRA Reliability Requirement row

- Adding the 2028/2029 Load Model to the 2027/2028 BRA run increases the FPR by 0.0962, but the Pool-wide average Accredited UCAP Factor (i.e., the overall accreditation of the resource mix) also increases by 0.0830. The increase in Pool-wide average Accredited UCAP Factor is caused by the lower extreme winter loads in the hourly load shapes for 2028/2029, which increase the overall accreditation of the 2027/2028 BRA resource mix (i.e., the same resource portfolio when measured against lower extreme winter loads yield a higher Pool-wide average Accredited UCAP Factor). However, this accreditation increase is accompanied by a higher FPR, which increases the targeted procurement of Accredited UCAP. Once the change in "Illustrative 2028/2029 BRA Total UCAP" and "Illustrative 2028/2029 BRA Reliability Requirement" are taken into account, it can be observed that the system becomes less tight by about 413 MW of Accredited UCAP (from -1,390 MW to -977 MW) due to adding the 2028/2029 Load Model to the 2027/2028 BRA run. This is consistent with the decrease in IRM due to the addition of the 2028/2029 Load Model described earlier, given that a decrease in IRM is a sign of less risk in the system (which should result in a system becoming less tight).

- The cumulative addition of the 2028/2029 Capacity Model to the previous run decreases both Pool-wide average Accredited UCAP Factor and FPR. Overall, the system becomes tighter because the reduction in "Illustrative 2028/2029 BRA Total AUCAP" (14,037 MW) is greater than the reduction in "Illustrative 2028/2029 BRA Reliability Requirement" (13,593 MW), resulting in a tightness metric equal to -1,421 MW (a reduction of -443 MW relative to the run prior adding the 2028/2029 Capacity Model). However, the tightness metric values when using the FPR and AUCAP Factor of the 2027/28 BRA and those of the 2028/29 BRA are similar (-1,390 MW vs -1,421 MW), which means that the 2028/29 FPR and ELCC value do not have a large impact on supply/demand tightness relative to the impact of the 2027/28 values.

- The 0.9232 FPR for 2029/2030 represents a decrease of 0.0169 relative to the FPR calculated for 2028/2029 (0.9401). **Table 2** provides the values for the FPR, Pool-wide average Accredited UCAP Factor , illustrative 2029/2030 Reliability Requirement, illustrative 2029/2030 total Accredited UCAP (AUCAP), and illustrative 2029/2030 BRA supply/demand tightness for each of the same three runs used to explain the change in IRM above.

Table 2. Additional Impacts due to changes from 2028/2029 BRA to 2029/2030 BRA

	2028/2029 BRA	2028/2029 BRA + 2029/2030 Load Model	2028/2029 BRA + 2029/2030 Load Model + 2029/2030 Capacity Model (2029/2030 BRA)
FPR	0.9401	0.9324 (-0.0077)	0.9232 (-0.0092)
Pool-wide average UCAP Factor	0.7834	0.7744 (-0.0090)	0.7668 (-0.0076)
Illustrative 2029/2030 BRA Total AUCAP (MW)*	159,033	157,206 (-1,827)	155,663 (-1,543)
Illustrative 2029/2030 BRA Reliability Requirement (MW)**	161,255	159,935 (-1,320)	158,356 (-1,579)
Illustrative 2029/2030 BRA Supply/Demand Tightness (MW) ***	-2,222	-2,728 (-506)	-2,693 (+35)

* Calculated as Total ICAP in 2029/2030 Run (203,004 MW) times Pool-wide average UCAP Factor row

** Calculated as 2029/2030 Forecasted Peak Load (171,530 MW) times FPR row

*** Calculated as Illustrative 2029/2030 BRA Total AUCAP row minus Illustrative 2029/2030 BRA Reliability Requirement row

- Adding the 2029/2030 Load Model to the 2028/2029 BRA run decreases the FPR by 0.0077, but the Pool-wide average Accredited UCAP Factor (i.e., the overall accreditation of the resource mix) also decreases by 0.0090. The decrease in Pool-wide average Accredited UCAP Factor is caused by the higher extreme winter loads in the hourly load shapes for 2029/2030, which decrease the overall accreditation of the 2028/2029 BRA resource mix (i.e., the same resource portfolio when measured against higher extreme winter loads yields a lower Pool-wide average Accredited UCAP Factor). However, this accreditation decrease is accompanied by a lower FPR, which decreases the targeted procurement of Accredited UCAP. Once the change in "Illustrative 2029/2030 BRA Total UCAP" and "Illustrative 2029/2030 BRA Reliability Requirement" are taken into account, it can be observed that the system becomes tighter by about 506 MW of Accredited UCAP (from -2,222 MW to -2,728 MW) due to adding the 2029/2030 Load Model to the 2028/2029 BRA run.

- The cumulative addition of the 2029/2030 Capacity Model to the previous run decreases both pool-wide Accredited UCAP Factor and FPR. The system becomes slightly less tight because the reduction in Illustrative 2029/2030 BRA Total Accredited UCAP (1,543 MW) is slightly less than the reduction in "Illustrative 2029/2030 BRA Reliability Requirement" (1,579 MW), resulting in a tightness metric equal to -2,693 MW (an increase of +35 MW relative to the run prior adding the 2029/2030 Capacity Model). Overall, the balance of supply/demand in the system is tighter when the FPR and AUCAP Factor of the 2029/2030 BRA are used compared to when using the corresponding values for the 2028/2029 BRA.

- The ELCC Class Ratings for 2029/2030, 2028/2029 (from the 2026 ELCC/RRS) compared to those for 2027/2028 (from the 2025 ELCC/RRS) are presented in **Table 3**.

Table 3. ELCC Class Ratings for the 2027/2028, 2028/2029, and 2029/2030 DYs(value within parentheses shows difference relative to previous Delivery Year value)

ELCC Class	2027/2028 Rating*	2028/2029 Rating	2029/2030 Rating
Onshore Wind	41%	34% (-7%)	37% (+3%)
Offshore Wind	67%	60% (-7%)	65% (+5%)
Fixed-Tilt Solar	7%	7% (+0%)	6% (-1%)
Tracking Solar	8%	10% (+2%)	7% (-3%)
Intermittent Landfill Gas	48%	50% (+2%)	50% (+0%)
Intermittent Hydropower	39%	35% (-4%)	34% (-1%)
Capacity Storage Resource (4-hr)	58%	59% (+1%)	57% (-2%)
Capacity Storage Resource (6-hr)	67%	68% (+1%)	66% (-2%)
Capacity Storage Resource (8-hr)	70%	71% (+1%)	69% (-2%)
Capacity Storage Resource (10-hr)	78%	78% (+0%)	76% (-2%)
Demand Resource	92%	91% (-1%)	90% (-1%)
Nuclear	95%	96% (+1%)	96% (+0%)
Coal	83%	85% (+2%)	84% (-1%)
Gas Combined Cycle	74%	78% (+4%)	75% (-3%)
Gas Combustion Turbine	61%	67% (+6%)	59% (-8%)
Gas Combustion Turbine Dual Fuel	77%	79% (+2%)	76% (-3%)
Diesel Utility	92%	93% (+1%)	92% (-1%)
Steam	72%	75% (+3%)	75% (+0%)
Waste to Energy Steam	83%	84% (+1%)	83% (-1%)
Oil-Fired Combustion Turbine	80%	83% (+3%)	81% (-2%)

*** Due to the RPM schedule, the 2027/2028 values were calculated as part of the 2025 ELCC/RRS**

- The majority of the 2028/2029 ELCC Class Ratings relative to the 2027/2028 values increase due to a decrease in winter risk share. The ELCC Classes with larger decreases are those with much better performance in winter risk hours than in summer risk hours, i.e., Onshore and Offshore Wind. The class with the largest increase in rating was the Gas Combustion Turbine class, which was also affected by the decrease in winter risk share in the 2028/2029 run. In addition to the above, some classes see changes that are slightly amplified due to a reduction of loss of load events in the model driven by performance during Winter Storm Elliott.

- The 2029/2030 ELCC Class Ratings relative to the 2028/209 values largely show a reversal of the increases observed in the 2028/29 values, reflecting the increase in winter risk share in the 2029/20230 run. As such, for example, the Onshore and Offshore Wind ELCC Class Ratings show increases of 3% and 5%, respectively, while the gas classes show decreases in their class ratings. Note that the changes in 2029/2030 ELCC Class Ratings (relative to 2028/2029) are not of the same magnitude as the changes in 2028/2029 ELCC Class Ratings (relative to 2027/2028) as other inputs to the runs, particularly the set of units in each class, differ.
- The 2028/2029 resource portfolio was developed:
  - Including Planned Resources that submitted a Notice of Intent to Offer for the 2028/2029 BRA
  - Including Installed Capacity ratings reflecting awarded 2028/2029 transitional system capability
  - Excluding Resources with announced deactivations scheduled to occur before June 1, 2029
  - Including Capacity Resources that have withdrawn their deactivation notice or are in the process of reactivating

The developments above resulted in an overall decrease of 1,508 MW ICAP in the 2028/2029 resource portfolio relative to the ICAP in the 2027/2028 resource portfolio.

- The 2029/2030 resource portfolio was developed in a similar manner:

Resulting in an overall increase of 6,133 MW ICAP in the 2029/2030 resource portfolio relative to the ICAP in the 2028/2029 resource portfolio.

- Consistent with the requirements of ReliabilityFirst (RF) Standard BAL-502-RFC-03, Resource Planning Reserve Requirements, the 2026 RRS provides a ten-year resource adequacy projection for the planning horizon that begins June 1, 2027, and extends through May 31, 2037. (See **Table 5**)
- Since FERC's approval of the resource adequacy reforms in docket ER24-99-000, PJM has calculated the IRM and FPR values shown in **Table 4.**

Table 4. Approved IRM and FPR values

Study Month/Year	Target Auction	IRM	FPR
March 2024	2025/2026 BRA	17.8%	0.9387
January 2025	2025/2026 3IA	17.8%	0.9380
March 2025	2026/2027 BRA	19.1%	0.9170
October 2025	2027/2028 BRA	20.0%	0.9260
January 2026	2026/2027 3IA	18.6%	0.9291
February 2026	2028/2029 BRA	20.0%	0.9401
August 2026	2029/2030 BRA	20.4%	0.9232

Introduction

Purpose

The PJM Reserve Requirement Study (RRS) is developed for the following purposes:

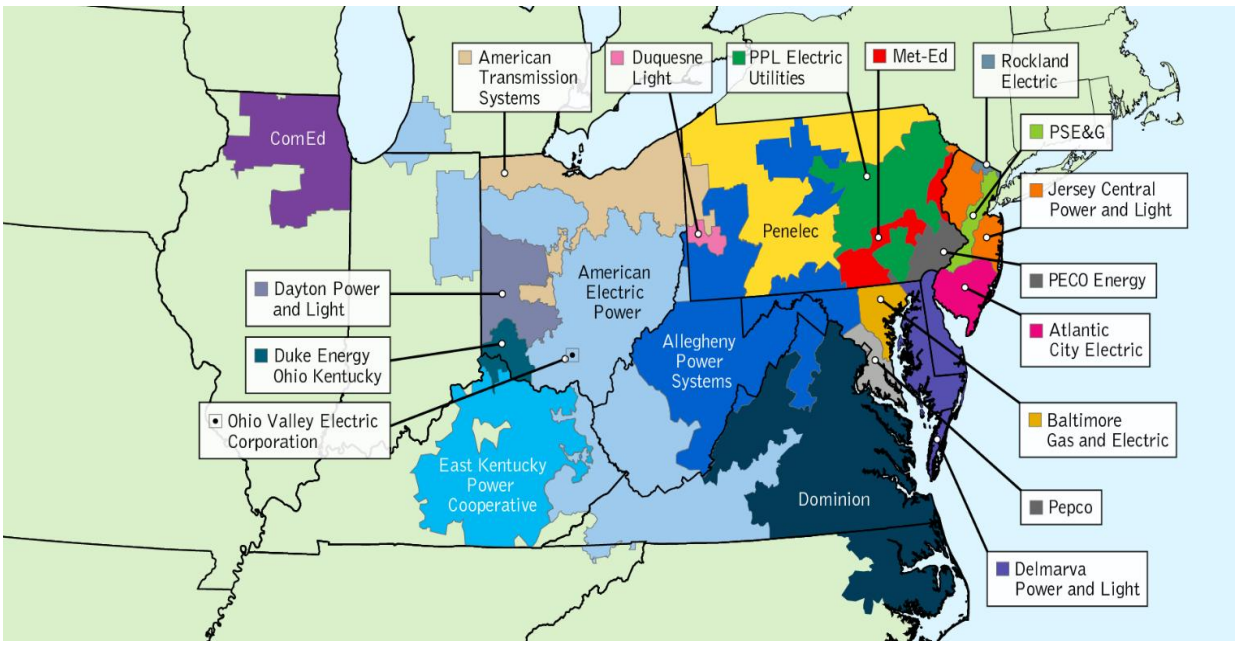
- Comply with the Reliability Principles and Standards as defined in the PJM Reliability Assurance Agreement (RAA) and ReliabilityFirst (RF) Standard BAL-502-RFC-03.
- Provide stakeholders with explanation and background for recently calculated RPM planning parameters as well as informational values for future Delivery Years.
- Provide stakeholders with information about the loss of load tool used by PJM to perform the above calculations including the underlying assumptions of the model.

Regional Modeling

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

Areas adjacent to the PJM Region are not modeled in this study. Instead, the Capacity Benefit of Ties (CBOT), which is used to decrease the targeted amount of capacity procured in RPM, was administratively set at 1.5% of the 50/50 peak load for all studied DYs.

Figure 3. Combined PJM Region Modeled



Summary of RRS Results

Eleven-Year RRS Results

Table 5 shows a ten-year-forward projection from the study for informational purposes. The Delivery Years for which the parameters were/are used in RPM auctions are highlighted in yellow.

Table 5. Eleven-Year Reserve Requirement Study

Delivery Year	Total ICAP (MW)	Total UCAP (MW)	IRM (%)	Pool Wide Avg AUCAP Factor (%)	FPR	Forecasted Peak Load (MW)	Total ICAP Requirement (MW)	Total UCAP Requirement (MW)	ICAP Surplus (MW)	UCAP Surplus (MW)*
2027/2028**	198,379	153,095	20.0	77.17	0.9260	164,186	196,202	152,036	2,177	1,059
2028/2029	196,871	154,234	20.0	78.34	0.9401	165,567	198,680	155,650	-1,809	-1,416
2029/2030	203,004	155,663	20.4	76.68	0.9232	171,530	206,522	158,356	-3,518	-2,693
2030/2031	207,263	154,959	21.7	74.76	0.9099	183,008	222,721	166,519	-15,458	-11,560
2031/2032	214,746	157,691	22.5	73.43	0.8995	191,017	233,996	171,820	-19,250	-14,129
2032/2033	221,291	160,878	22.9	72.70	0.8935	198,915	244,467	177,731	-23,176	-16,852
2033/2034	227,605	162,052	23.1	71.20	0.8765	206,084	253,689	180,633	-26,084	-18,580
2034/2035	228,247	160,082	24.4	70.14	0.8725	211,882	263,581	184,867	-35,334	-24,786
2035/2036	231,197	160,333	25.6	69.35	0.8710	216,872	272,391	188,896	-41,194	-28,563
2036/2037	235,823	161,384	26.4	68.43	0.8650	222,106	280,742	192,122	-44,919	-30,738

* The UCAP Surplus does not account for the fact that in RPM the offers of resources are capped at CIRs. CIRs can be lower than the Accredited UCAP of resources. This means that, in RPM, the UCAP Surplus can be lower than in the table above.

** Due to the RPM schedule, the 2027/2028 values were calculated as part of the 2025 ELCC/RRS not the 2026 ELCC/RRS.

- The IRM and FPR provide information about the amount of ICAP and UCAP, respectively, that is necessary for the PJM system to meet the 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)
- Specifically, multiplying the “Forecasted Peak Load” column times one plus the “IRM” column produces the “Total ICAP Requirement” column. Similarly, multiplying the “Forecasted Peak Load” column times the “FPR” column produces the “Total UCAP Requirement column”.
- The “FPR” column is derived by multiplying one plus the “IRM “column times the “Pool Wide Avg AUCAP Factor”. Therefore, the “Pool-Wide Avg AUCAP Factor” can be thought of as the Accredited UCAP rating of the resource portfolio for each Delivery Year.

- The "Forecasted Peak Load" column values are taken from the 2026 PJM Load Forecast Report and represent the 50/50 (i.e., median) peak loads except the value for 2027/2028, which is taken from the 2025 PJM Load Forecast Report.
- The "Total ICAP" and "Total UCAP" columns provide the assumed amount of ICAP and UCAP values, respectively. Both columns include Demand Resources and assumed external firm capacity purchases and sales.
- "ICAP Surplus" column is the difference of the "Total ICAP" and "Total ICAP Requirement" columns. Similarly, the "UCAP Surplus" is the difference between the "Total UCAP" and "Total UCAP Requirement" columns.
- The "ICAP Surplus" and "UCAP Surplus" columns show that the PJM system has enough resources to meet the LOLE criterion of 1 day in 10 years in Delivery Year 2027/2028. For the rest of the Delivery Years, the ICAP Surplus and UCAP Surplus values are negative given the consistently increasing Forecasted Peak Load Values as well as the consistently increasing IRM values.
- The IRM values consistently increase because the changes in the assumed resource portfolio consider additions of resources that have lower Accredited UCAP than the resources that are retired.
- The "Pool-Wide Avg UCAP Factor" values are reflective of availability patterns of resources in the resource portfolio during critical hours (i.e., hours where additional energy reduces system unserved energy). Factors that impact availability patterns include:
  - Forced, Planned and Maintenance Outages for Unlimited Resources (non-correlated as well as correlated)
  - Ambient derates for Unlimited Resources
  - Unavailability of Variable Resources (non-correlated and correlated)
  - Energy constraints of Limited Duration Resources and Combination Resources
  - Forced Outage Rates of Limited Duration Resources and Combination Resources
  - Expected performance of Demand Resources
- The "Total ICAP" and "Total UCAP" columns:
  - For 2027/2028, 2028/2029, and 2029/2030, the values include Planned Resources that submitted a Notice of Intent to Offer for the respective BRAs and Capacity Resources that have withdrawn their deactivation notice or are in the process of reactivating while excluding Resources with announced deactivations.
  - For the rest of the Delivery Years, the values include projected additions and retirements developed by a vendor.

Recommendations

- Installed Reserve Margin (IRM) – based on the study results and the additional considerations mentioned above, PJM recommends, and the PJM Board approved, an IRM value of 20.0% for the 2028/2029 Delivery Year and an IRM value of 20.4% for the 2029/2030 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) * (Pool-wide Average Accredited UCAP Factor)*

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

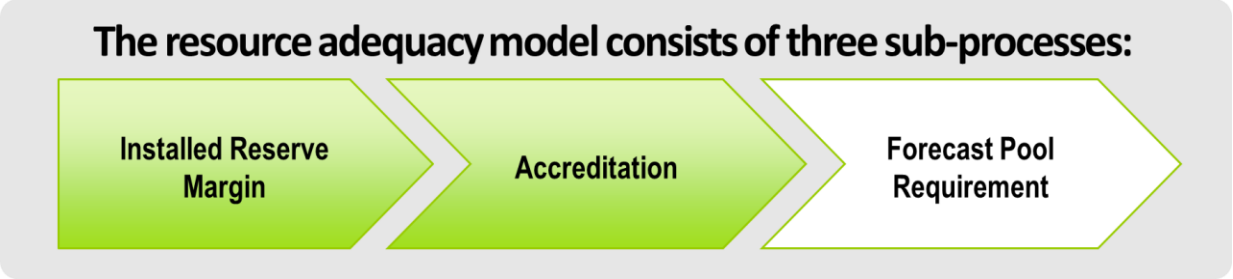
2028 / 2029 Delivery Year	*FPR = (1 + 0.200) * (0.7834) = 0.9401*
2029 / 2030 Delivery Year	*FPR = (1 + 0.204) * (0.7668) = 0.9232*

Model Overview

General Overview

As shown in **Figure 4**, the process to calculate the IRM and FPR for a given Delivery Year can be divided into three subprocesses:

Figure 4. Model Process Overview



The IRM Subprocess determines via probabilistic modeling the 50/50 "solved" peak load that a given resource portfolio for a given Delivery Year can serve while meeting the LOLE criterion of 1 day in 10 years. Since the total ICAP of the resource portfolio is an input to the process and the CBOT value is administratively set, the IRM can be calculated by finding the 50/50 "solved" peak load.

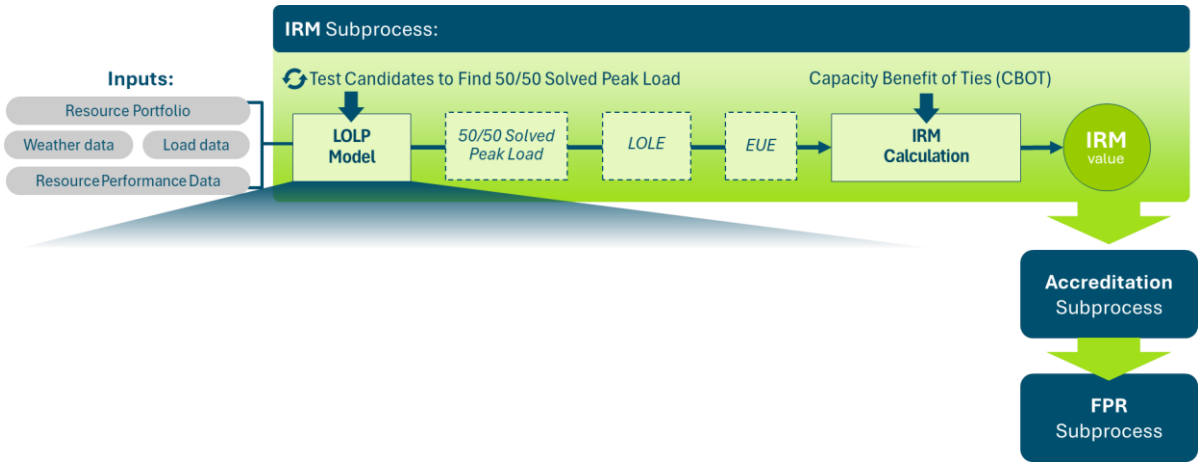
The Accreditation Subprocess determines via probabilistic modeling the Accredited UCAP of each resource included in the resource portfolio. This entails identifying the ELCC Class Ratings and the Unit-Specific ratings, which in turn are calculated by determining the Expected Unserved Energy (EUE) improvement that an incremental quantity of an ELCC Class or Unit, as appropriate, provides to the PJM system when the LOLE criterion of 1 day in 10 years is met, relative to the EUE improvement that an incremental quantity of perfect capacity provides to the system.

The FPR Subprocess is the simplest of the three subprocess, as the FPR is calculated by directly using outputs from the two previous subprocesses: the IRM and the total AUCAP in the system.

Underlying the three subprocesses is PJM's Loss of Load Probability (LOLP) Model. While described in further detail later in the report, the LOLP Model is a probabilistic model that calculates resource adequacy metrics, such as Loss of Load Expectation (LOLE), Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE), by simulating the balance of supply and demand in the PJM system chronologically hour by hour under multiple annual scenarios. Supply and demand are modeled as a function of weather (Temperature Humidity Index, specifically), using historical resource performance data to reflect resource availability, and reflecting the energy constraints of certain resources. The IRM Subprocess can be thought of as a calibration of the LOLP Model to meet the LOLE criterion of 1 day in 10 years while the Accreditation Subprocess can be thought of as the standard with which resources' resource adequacy contributions are compared to each other depending on their modeled performance during the critical hours identified by the LOLP Model when the system meets the criterion.

IRM Subprocess

Figure 5. IRM Subprocess Overview



The IRM Subprocess depends on several inputs including resource portfolio, weather data, load data and resource performance data, shown in **Figure 5**. These inputs are fed into the core of the IRM Subprocess, the LOLP Model. Since the 50/50 Forecasted Load that the resource portfolio can serve while meeting the Reliability Criteria is unknown, a candidate solved load is iteratively input into the LOLP model until the model finds 50/50 solved peak load that meets the Reliability Criteria. Once the 50/50 solved peak load is found, the IRM Calculation can proceed by subtracting the administratively set Capacity Benefit of Ties.

Inputs

Resource Portfolio

A resource portfolio for each studied Delivery Year is an input into the model. In the 2026 RRS, for Delivery Years 2028/2029 and 2029/2030, the portfolio includes existing[1] resources, planned resources that submitted a Notice of Intent for the respective BRA, and resources that have withdrawn deactivation notices or that are in the process of reactivating prior to the start of the respective Delivery Year and excludes resources with announced deactivations scheduled to occur before the end of each of the respective Delivery Years. For the other Delivery Years in the 2026 RRS[2], the resource portfolios are derived by using a forecast of additions and deactivations produced by a vendor.

Table 6 shows the resources portfolios for Delivery Years 2028/2029 and 2029/2030 in the 2026 RRS. The resource portfolios for the rest of the Delivery Years are available upon request to ELCC@pjm.com.

[1] Existing Generation Capacity Resources as well as external resources that are pseudo-tied to PJM

[2] The resource portfolio for 2027/2028 was taken from the 2025 RRS and is based on information for the 2027/2028 BRA.

Table 6. Resource Portfolio for the 2028/2029 and 2029/2030 Delivery Years

ELCC Class	Effective Nameplate Capacity 2028/2029 (MW)	Effective Nameplate Capacity 2029/2030 (MW)	Installed Capacity 2028/2029 (MW)	Installed Capacity 2029/2030 (MW)
Onshore Wind	13,137	14,609	4,061	3,599
Offshore Wind	Small Sample Size	Small Sample Size	Small Sample Size	Small Sample Size
Solar Fixed	3,483	3,136	1,916	1,585
Solar Tracking	20,691	24,664	13,530	14,900
Intermittent Landfill	146	144	101	100
Intermittent Hydropower	721	820	515	545
Capacity Storage Resources (4, 6, 8, 10-hour duration)	6,836	7,144	6,836	7,144
Solar-Storage Hybrid	Small Sample Size	Small Sample Size	Small Sample Size	Small Sample Size
Demand Resources	n/a	n/a	8,396	8,711
Nuclear	n/a	n/a	32,316	32,220
Coal	n/a	n/a	31,906	31,304
Gas Combined Cycle (Single and Dual Fuel)	n/a	n/a	57,719	59,922
Gas Combustion Turbine	n/a	n/a	10,382	11,378
Gas Combustion Turbine Dual Fuel	n/a	n/a	12,808	14,205
Diesel Utility	n/a	n/a	331	328
Steam	n/a	n/a	9,282	10,284
Waste to Energy Steam	n/a	n/a	720	739
Oil-Fired Combustion Turbine	n/a	n/a	2,851	2,887
Hydropower with Non-Pumped Storage	2,057	2,015	1,987	1,945
Other Unlimited Resources	n/a	n/a	447	442
TOTAL	216,745	227,469	196,871	203,004

Note that the ICAP ratings in **Table 6** include any transitional system capability that was awarded for the respective Delivery Year. Also, in **Table 6**, some Effective Nameplate Capacity and Installed Capacity values are either non-applicable (n/a) or cannot be released due to confidentiality rules (small sample size of resources/owners in the ELCC Class). Note that the ICAP values and ENC values are annual and as such, are not assumed or modeled to vary by season.

Weather Data

The weather data used in the 2026 RRS is hourly Temperature Humidity Index (THI) for the period June 1, 1993, through May 31, 2025 (i.e., DY 1993 through DY 2024). The weather data is used in two ways:

On the load side: the PJM Load Forecast team develops hourly load scenarios for the entire RTO using weather data (temperature, humidity, wind speed) for each of the PJM transmission zones. It does so by first estimating the hourly load for each transmission zone and then hour by hour adding the zonal values to calculate the RTO values. The zonal process is performed by solving the hourly zonal equations (which are estimated via a zonal regression model) using the above weather data as well as distributed solar generation, forecast adjustments (data centers and peak shaving), behind-the-meter battery storage, and electric vehicles. In addition, to capture the fact that historical weather patterns that occurred on a certain day could also have occurred in surrounding days, each yearly weather pattern is shifted moving forward six days and backward six days, providing 13 different weather scenarios for each historical year. More details about this methodology can be found in the 2026 PJM Long-Term Load Forecast Supplement.

On the resource performance side: for each hour in the period June 1, 1993, through May 31, 2025, a load-weighted RTO THI value is determined (load-weighted because the THI data is at the zonal level). Then, the maximum hourly RTO-wide THI is determined for each summer day in the above period, while for each winter day in the above period, the minimum hourly RTO-wide THI is determined.[3] The objective of this step in the process is to associate each day in the period June 1, 1993, through May 31, 2025, with a single hourly RTO-wide THI value. The summer days are then separated from the winter days and grouped in Weather Bins (the same is done for the winter days) based on the maximum hourly RTO-wide THI values (in the case of winter, this is done using the minimum hourly RTO-wide THI values). This is accomplished by feeding the collection of maximum hourly RTO-wide THI values to the Freedman Diaconis algorithm, an algorithm commonly used to derive histograms. The same is done with the collection of minimum hourly RTO-wide THI values for the winter days.

As discussed in the load section above, weather data starting on June 1, 1993, is used to develop the load scenarios. On the resource performance side, specifically for Unlimited Resources and Variable Resources, the model uses data starting on June 1, 2012. This is because data prior to June 1, 2012, was either unavailable or deemed not representative of the current characteristics of the resources in the resource portfolio. Therefore, to differentiate the bins that include days back to June 1, 1993 (i.e., the Weather Bins), Resource Performance Bins include days dating back to June 1, 2012.

In the 2026 RRS, the output of the Freedman Diaconis algorithm for winter and summer resulted in Weather Bins and Resource Performance Bins with small sample sizes, especially for the Resource Performance Bins. To avoid this outcome, PJM merged some of the Weather Bins as follows.

[3] Winter comprises the months of November, December, January, February, March and April. Summer comprises the rest of the months.

Merging of Winter min0, min1, min2, min3. min4, min5 (bins covering winter days with low RTO-wide THI)

Table 7 shows the winter bins that cover days with low RTO-wide THI values pre-merging. The table shows the lower and upper bound RTO THI values as well as the number of days included in the bins since 06/01/1993 and since 06/01/2012. The far-right column shows the bin with which the original bin was merged in the merging process.

Table 7. Pre-merging winter bins covering days with the lowest RTO-wide THI values

Season	Bin Name	Lower Bound RTO THI	Upper Bound RTO THI	Number of Days since 06/01/1993	Number of Days since 06/01/2012	Merged with
Winter	min0	-10.52	-8.14	1	0	min5
Winter	min1	-8.14	-5.76	0	0	min5
Winter	min2	-5.76	-3.37	1	0	min5
Winter	min3	-3.37	-0.99	2	1	min5
Winter	min4	-0.99	1.40	7	2	min5
Winter	min5	1.40	3.78	7	4	min5

The post-merging Winter min5 Weather Bin and Resource Performance Bin have the following characteristics, shown in **Table 8.** Compared to the corresponding merged bin in the 2025 ELCC/RRS, there are no major differences.

Table 8. Post-merging winter bin covering days with the lowest RTO-wide THI values

Season	Bin Name	Lower Bound RTO THI	Upper Bound RTO THI	Number of Days since 06/01/1993	Number of Days since 06/01/2012
Winter	min5	-10.52	3.78	18	7

Merging of Winter min31, min30 (bins covering winter days with high RTO-wide THI)

Table 9 shows the winter bins that cover days with high RTO-wide THI values pre-merging. The table shows the lower and upper bound RTO THI values as well as the number of days included in the bins since 06/01/1993 and since 06/01/2012. The far-right column shows the bin with which the original bin was merged in the merging process.

Table 9. Pre-merging winter bins covering days with the highest RTO-wide THI values

Season	Bin Name	Lower Bound RTO THI	Upper Bound RTO THI	Number of Days since 06/01/1993	Number of Days since 06/01/2012	Merged with
Winter	min30	61.00	63.39	16	7	min30
Winter	min31	63.39	65.78	2	0	min30

The post-merging Winter min30 Weather Bin and Resource Performance Bin has the following characteristics, shown in **Table 10**. Compared to the corresponding merged bin in the 2025 ELCC/RRS, the bin in the 2026 ELCC/RRS has one additional day after 06/01/2012 (in the 2025 ELCC/RRS, the merged bin had 6 days after 06/01/2012).

Table 10. Post-merging winter bin covering days with the highest RTO-wide THI values

Season	Bin Name	Lower Bound RTO THI	Upper Bound RTO THI	Number of Days since 06/01/1993	Number of Days since 06/01/2012
Winter	min30	61.00	65.78	18	7

Merging of Summer max17, max18, max19, max20 (bins covering summer days with low RTO-wide THI)

Table 11 shows the summer bins that cover days with low RTO-wide THI values pre-merging. The table shows the lower and upper bound RTO THI values as well as the number of days included in the bins since 06/01/1993 and since 06/01/2012. The far-right column shows the bin with which the original bin was merged in the merging process. In the 2025 ELCC/RRS, only max17, max18 and max19 were merged, without including max20. This resulted only in 4 days after 06/01/2012 in the merged bin. Because 4 is a small sample size to sample from, in the 2026 ELCC/RRS, max20 was added to the merged bin resulting in 11 days after 06/01/2012. Note that this merged bin has no impact on the study results as summer days with low RTO-wide THI exhibit low loads.

Table 11. Pre-merging summer bins covering days with the lowest RTO-wide THI values

Season	Bin Name	Lower Bound RTO THI	Upper Bound RTO THI	Number of Days since 06/01/1993	Number of Days since 06/01/2012	Merged with
Summer	max17	41.23	43.50	3	0	max20
Summer	max18	43.50	45.77	5	1	max20
Summer	max19	45.77	48.04	13	3	max20
Summer	max20	48.04	50.31	24	7	max20

The post-merging Summer max20 Weather Bin and Resource Performance Bin has the following characteristics, shown in **Table 12**.

Table 12. Post-merging summer bin covering days with the lowest RTO-wide THI values

Season	Bin Name	Lower Bound RTO THI	Upper Bound RTO THI	Number of Days since 06/01/1993	Number of Days since 06/01/2012
Summer	max20	41.23	50.31	45	11

Merging of Summer max35, max36 (bins covering summer days with high RTO-wide THI)

Table 13 shows the summer bins that cover days with high RTO-wide THI values pre-merging. The table shows the lower and upper bound RTO THI values as well as the number of days included in the bins since 06/01/1993 and since 06/01/2012. The far-right column shows the bin with which the original bin was merged in the merging process.

Table 13. Pre-merging summer bins covering days with the highest RTO-wide THI values

Season	Bin Name	Lower Bound RTO THI	Upper Bound RTO THI	Number of Days since 06/01/1993	Number of Days since 06/01/2012	Merged with
Summer	max35	82.08	84.35	75	29	max35

Summer	max36	84.35	86.62	6	1	max35

The post-merging Summer max35 Weather Bin and Resource Performance Bin has the following characteristics, as shown in **Table 14**. Compared to the corresponding merged bin in the 2025 ELCC/RRS, the bin in the 2026 ELCC/RRS has two additional days after 06/01/2012 (in the 2025 ELCC/RRS, the merged bin had 28 days after 06/01/2012). The two additional days in this merged bin, 07/15/2024 and 07/16/2024, are from the delivery year that was rolled in in the 2026 ELCC/RRS.

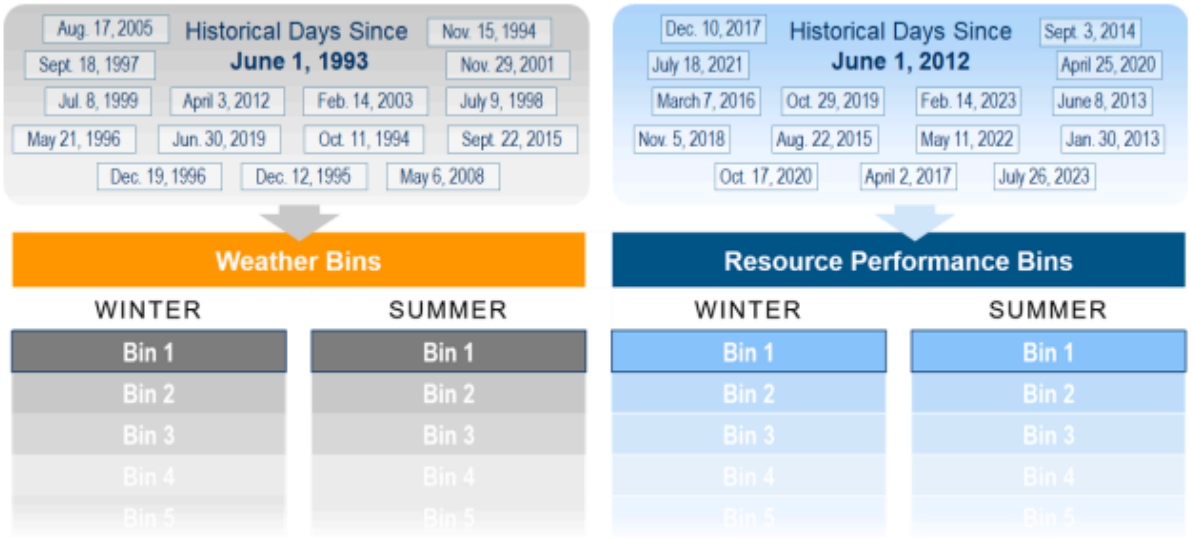
Table 14. Post-merging summer bin covering days with the highest RTO-wide THI values

Season	Bin Name	Lower Bound RTO THI	Upper Bound RTO THI	Number of Days since 06/01/1993	Number of Days since 06/01/2012
Summer	max35	82.08	86.62	81	30

All Weather Bins, for summer and winter, pre-merging and post-merging, as well as the days included in each bin are posted on the Effective Load Carrying Capability page on PJM.com.

A schematic of Weather Bins and Resource Performance Bins is shown in 22**Figure 6**.

Figure 6. Example of Weather Bins and Resource Performance Bins



Load Data

As described above in the Weather Data subsection, the hourly load scenarios for the entire RTO are developed by the PJM Load Forecast team by aggregating the hourly load scenarios developed for each transmission zone. The hourly load scenarios are specific for each Delivery Year studied given that other variables impacting forecasted load are likely to differ for different Delivery Years.

The hourly load scenarios used in the 2026 RRS are calculated based on weather data from the period June 1, 1993, through May 31, 2025 (i.e., DY 1993 through DY 2024). As noted earlier, each yearly weather pattern is shifted moving forward six days and backward six days, providing 13 different weather scenarios for each historical year. Therefore, considering that there are 32 Delivery Years in the period June 1, 1993, through May 31, 2025, there are 32 x 13 = 416 hourly load scenarios in the 2026 RRS.

In addition, to account for the error between observed daily peak loads and the fitted daily peak loads produced by the PJM Load Forecast regression model, the hourly loads of each day in each hourly load scenario are adjusted randomly by a factor, determined for each day, derived by randomly sampling from a normal distribution. In the 2026 RRS, the normal distribution utilized was one with a mean equal to 0 and a standard deviation equal to 1.1% (the corresponding values used in the 2025 RRS were 0 and 1.2%, respectively). This is implemented as illustrated by **Figure 7** showing the first two days of an hourly load scenario derived with weather data from Delivery Year 1993. The Original Load column shows the values as provided by the PJM Load Forecast team. The Adjustment Factor column shows the random factors derived from the above normal distribution for each day; note that the values can be positive or negative. The Final Load column shows the loads used in the model; those loads adjusted by a factor greater than 1 will increase relative to the values provided by the PJM Load Forecast team while those adjusted by a factor less than 1 will decrease.

Figure 7. Example of hourly load scenario derived with weather data from Delivery Year 1993

Weather Day/HourBeginning	Original Load	Adjustment Factor	Final Load
June 1st 1993 0:00	L0	+0.3%	1.003 * L0
June 1st 1993 1:00	L1	+0.3%	1.003 * L1
…	…	…	…
June 1st 1993 23:00	L23	+0.3%	1.003 * L23
June 2nd 1993 0:00	L24	-0.5%	0.995 * L24
June 2nd 1993 1:00	L25	-0.5%	0.995 * L25
…	…	…	…
June 2nd 1993 23:00	L47	-0.5%	0.995 * L47

All 416 hourly load scenarios for 2028/2029 and 2029/2030 adjusted by the Adjustment Factor are posted on the ELCC webpage. Note that the posted values have been per unitized on the respective 50/50 Forecasted Peak Load values (in other words, to convert to megawatt values, the values in the files should be multiplied by the 50/50 Forecasted Peak Load or a Candidate 50/50 Forecasted Peak Load, as suitable).

Resource Performance Data

Different resource performance inputs are required based on the type of resource included in the resource portfolio.

Unlimited Resources – Forced Outages and Ambient Derates

For each resource in the Unlimited Resources category, an hourly time series showing the ICAP share of the resource on a forced outage is required. In the 2026 RRS, the time series covers all hours in the period June 1, 2012, through May 31, 2025. A resource that has been in service for the entirety of this period is labeled as Mature; a resource that has been in service for a portion of the period is labeled as Immature; a resource that has not been in service for any portion of the period is labeled as Planned. For Mature resources, the time series is developed using forced outage data submitted to eGADS; for hours in the period in which Immature and Planned resources do not have forced outage data, a putative value is calculated using forced outage data from eGADS for other units in the class that were in service during that hour. **Table 15** illustrates the forced outages time series for four units in an illustrative ELCC Class X. Two of the units are Mature (Unit 1 and Unit 2), Unit 3 is Immature and Unit 4 is Planned. The time stamps in which data is not available are marked with an "-" symbol.

Table 15. Example of forced outages time series for four units

Time Stamp (HB)	Unit 1 in Class X with ICAP I1 (Mature)	Unit 2 in Class X with ICAP I2 (Mature)	Unit 3 in Class X with ICAP I3 (Immature)	Unit 4 in Class X with ICAP I4 (Planned)
June 1, 2012, 0:00	0.4	0.2	-	-
June 1, 2012, 1:00	0.2	0.1	-	-
June 1, 2012, 2:00	1.0	0.0	0.7	-
…	…	…	…	…
May 31, 2024, 23:00	0.8	0.9	0.4	-

Table 16 illustrates the process of developing putative data for the time stamps in which data is not available for the Immature and Planned units. The process uses forced outage data from other units that were in service during that hour.

Table 16. Example of developing putative data in forced outages time series for immature and planned units

Time Stamp (HB)	Unit 1 in Class X with ICAP I1 (Mature)	Unit 2 in Class X with ICAP I2 (Mature)	Unit 3 in Class X with ICAP I3 (Immature)	Unit 4 in Class X with ICAP I4 (Planned)
June 1, 2012, 0:00	0.4	0.2	(0.4 x I1 + 0.2 x I2)/ (I1 + I2)	(0.4 x I1 + 0.2 x I2)/ (I1 + I2)
June 1, 2012, 1:00	0.2	0.1	(0.2 x I1 + 0.1 x I2)/ (I1 + I2)	(0.2 x I1 + 0.1 x I2)/ (I1 + I2)
June 1, 2012, 2:00	1.0	0.0	0.7	(1.0 x I1 + 0.0 x I2 + 0.7 * I3)/ (I1 + I2 + I3)
…	…	…	…	…
May 31, 2024, 23:00	0.8	0.9	0.4	(0.8 x I1 + 0.9 x I2 + 0.4 * I3)/

				(I1 + I2 + I3)

A Forced Outage time series for an entire ELCC Class can also be developed by calculating an ICAP-weighted hourly forced outage rate (after all missing values for Immature and Planned units have been calculated). In the example shown in **Table 16**, such a time series can be determined by calculating the ICAP-weighted average value for each row in the table.

The hourly forced outage time series for the ELCC Classes classified as Unlimited Resources for 2028/2029 and 2029/2030 are posted on the ELCC webpage. Note that the forced outage time series for ELCC Classes under unit-specific treatment are not included in the above postings.

The process to calculate the hourly ambient derate time series is identical to the process to develop the hourly forced outage time series save for the fact that the source of the data is eDART. The hourly ambient derate time series for the ELCC Classes classified as Unlimited Resources for 2028/2029 and 2029/2030 are posted on the ELCC webpage.

Unlimited Resources – Planned Outages and Maintenance Outages

For each resource in the Unlimited Resources category, the planned and maintenance outage requirement is calculated in terms of MW*week / year. This requirement is calculated by using planned and maintenance outage data from eGADS in the period June 1, 2012, through May 31, 2025. For Mature units, the calculation of the requirement is based on all the hours during the period that the unit registered a planned or maintenance outage. For Immature units, the calculation is performed based on a weighted average of the requirement calculated with: i) the planned and maintenance outage data after the unit came in service and ii) a class average requirement calculated using planned and maintenance outage data from in-service units in the same ELCC Class. The weights in the weighted average calculation are: i) the share of hours in the period in which the unit was in service and ii) one minus the previous quantity. For Planned units, the requirement corresponds to the class average requirement calculated using planned and maintenance outage data from in service units in the same ELCC Class.

Variable Resources

For each resource in the Variable Resources category, an hourly time series showing the Effective Nameplate Capacity (ENC) share of the resource that is available is required. In the 2026 RRS, the time series covers all hours in the period June 1, 2012, through May 31, 2025. A resource that has been in service for the entirety of this period is labeled as Mature; a resource that has been in service for a portion of the period is labeled as Immature; a resource that has not been in service for any portion of the period is labeled as Planned. For Mature resources, the time series is developed using PJM Settlements data showing the historical availability of the resource; for hours in the period in which Immature and Planned resources do not have forced outage data, a putative value is calculated by using an availability backcast that is derived based on historical weather data consistent with the particular site conditions and generator configurations for each resource.

Furthermore, since the ENC values for Variable Resources can exceed the assessed deliverability of such resources, the values in the above hourly availability time series are capped by: (i) the greater of the unit's CIR megawatt value, or the transitional system capability awarded for the applicable Delivery Year during hours in the months of June through October and the following May of the Delivery Year and ii) the unit's assessed deliverability as defined in PJM Manual 14B: PJM Region Transmission Planning Process for the applicable Delivery Year during hours in the

months of November through April of the Delivery Year. Specifically, for winter hours beginning 0, 1, 2, 3, 4, 5, 6, 7, 8, 18, 19, 20, 21, 22, 23, the cap is the winter deliverability megawatts, while for winter hours beginning 9, 10, 11, 12, 13, 14, 15, 16, 17, the cap is the light load deliverability megawatts. Also, the hourly availability time series of a Variable Resource is adjusted to reflect a unit's actual historical curtailments. As shown in **Table 17,** in the 2026 RRS, the assessed deliverability for Variable Resources is as follows:

Table 17. Assessed Deliverability caps for wind and solar ELCC Classes

ELCC Class	Zone	Summer Deliverability	Winter Deliverability MW (as percent of ENC)	Light Load Deliverability MW (as percent of ENC)
Onshore Wind	MAAC	Max(CIR, Transitional Deliv)	71%	63%
Onshore Wind	PJMWEST	Max(CIR, Transitional Deliv)	83%	79%
Onshore Wind	DOM	Max(CIR, Transitional Deliv)	72%	68%
Offshore Wind	MAAC	Max(CIR, Transitional Deliv)	93%	88%
Offshore Wind	DOM	Max(CIR, Transitional Deliv)	98%	94%
Solar Fixed	MAAC	Max(CIR, Transitional Deliv)	5%	51%
Solar Fixed	PJMWEST	Max(CIR, Transitional Deliv)	5%	60%
Solar Fixed	DOM	Max(CIR, Transitional Deliv)	5%	57%
Solar Tracking	MAAC	Max(CIR, Transitional Deliv)	5%	53%
Solar Tracking	PJMWEST	Max(CIR, Transitional Deliv)	5%	53%
Solar Tracking	DOM	Max(CIR, Transitional Deliv)	5%	58%

The Landfill Intermittent ELCC Class and Intermittent Hydropower ELCC Class are not included in **Table 17** because resources in those classes are studied for deliverability, under all studied scenarios, at their ICAP. Therefore, ICAP is the value at which the output of these resources is capped during all hours of the Delivery Year.

Limited Duration Resources

For each resource in the Limited Duration Resources category, an EFORd value is required. The EFORd value is calculated using the most recent five-year period of data submitted to eGADS. For the 2026 RRS, the data period used was October 1, 2019 through September 30, 2025.

Demand Resources

Demand Resources are modeled in bulk. In other words, no data for specific DR providers is required. The only input required for Demand Resources performance is the expected hourly availability in the aggregate as a function of the Nominated ICAP for a Delivery Year. This performance varies by season, specifically, in the 2026 RRS (note that the seasonal performance shapes in the 2025 RRS are the same as in the 2026 RRS):

For summer, the total hourly availability is calculated as the Nominated ICAP times F, where F is defined as the ratio of simulated hourly load to 50/50 peak load. **Table 18** shows an illustration of the above where F varies by hour as illustrated in the A1993 Load Scenario column.

Table 18. Example of Hourly DR Availability in Summer Season

Hour	A1993 Load Scenario	Nominated DR ICAP for DY	DR Available In Hour
1	0.515	Y	0.515 x Y
2	0.499	Y	0.499 x Y
3	0.489	Y	0.489 x Y
…	…	…	…
929	1.038	Y	1.038 x Y

For winter, the total hourly availability is calculated based on the following 24-hour DR availability shape, which is applied to each day of the winter season regardless of load level in the load scenarios. This availability shape is estimated based on the most recent DR registrations in RPM. **Table 19** shows the hourly DR availability shape used in the 2026 RRS, column named DR Availability in Winter Hour.

Table 19. Example of Hourly DR Availability in Winter Season

Hour	DR Availability in Winter Hour (as share of Nominated ICAP)	Nominated DR ICAP for DY	DR Available In Hour
1	0.785	Y	0.785 x Y
2	0.769	Y	0.769 x Y
3	0.772	Y	0.772 x Y
4	0.783	Y	0.783 x Y
5	0.801	Y	0.801 x Y
6	0.831	Y	0.831 x Y
7	0.927	Y	0.927 x Y
8	0.963	Y	0.963 x Y
9	1.000	Y	1.000 x Y
10	1.014	Y	1.014 x Y
11	1.020	Y	1.020 x Y
12	1.027	Y	1.027 x Y
13	1.020	Y	1.020 x Y
14	1.026	Y	1.026 x Y
15	1.002	Y	1.002 x Y
16	0.989	Y	0.989 x Y
17	0.968	Y	0.968 x Y
18	0.946	Y	0.946 x Y

Hour	DR Availability in Winter Hour (as share of Nominated ICAP)	Nominated DR ICAP for DY	DR Available In Hour
19	0.938	Y	0.938 x Y
20	0.922	Y	0.922 x Y
21	0.909	Y	0.909 x Y
22	0.870	Y	0.870 x Y
23	0.839	Y	0.839 x Y
24	0.825	Y	0.825 x Y

Combination Resources Except Hydro With Non-Pumped Storage

For each resource in the Combination Resources category, an EFORd value is required. The EFORd value is calculated using the most recent five-year period of data submitted to eGADS. For the 2026 RRS, the data period used was October 1, 2020 through September 30, 2025.

In addition, for each resource in the Combination Resources category except Hydro with Non-Pumped Storage, PJM needs to know if it can charge from the grid (i.e., open-loop) or if it cannot (i.e., closed-loop).

The ICAP of each Combination resource sets the cap for the maximum hourly output in the model.

Combination Resources – Hydro with Non-Pumped Storage

For each Hydro with Non-Pumped Storage resource, an EFORd value is required. The EFORd value is calculated using the most recent five-year period of data submitted to eGADS. For the 2026 RRS, the data period used was October 1, 2020 through September 30, 2025.

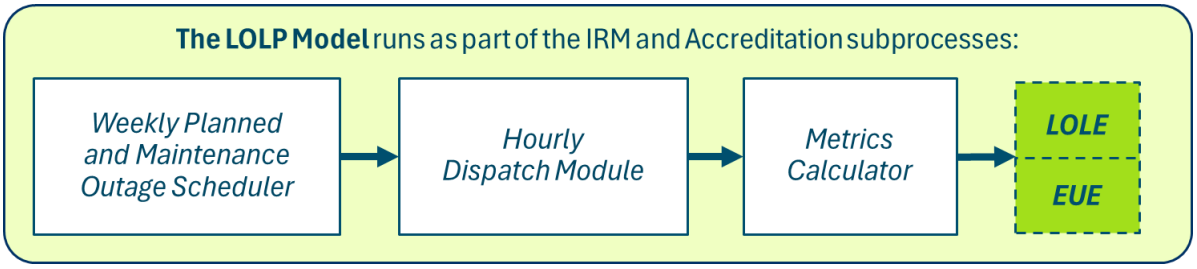
In addition, for the 2026 RRS, the following data inputs are used for Hydro with Non-Pumped Storage resources to model the intermittent component of these resources as well as the limited-duration (i.e. storage) component:

- Hourly Maximum Power for each month in the period June 1, 2012, through May 31, 2025. This value, if lower than the amount of CIRs of a resource, establishes the maximum available output to be modeled for the resource when using performance from a specific month in the historical period (the dispatch of resources is discussed later in the report).
- Minimum Allowable Water Flow for each day in the period June 1, 2012, through May 31, 2025. This value establishes the amount of water (in cubic feet of water) that is available to a resource to be converted into power for each hour in the historical period but that cannot be used to refill the storage component of the resource.
- Monthly average values for the ratio of the number of cubic feet of water required to produce a single megawatt-hour for each month in the period June 1, 2012, through May 31, 2025. This is used to convert the Minimum Allowable Water Flow above into megawatts to be used in the model.

- 24-hour rolling average streamflow data in cubic feet per hour for each hour in the period June 1, 2012, through May 31, 2025. This value, in conjunction with the monthly average values that can be used to convert water into power, establishes the historical hourly megawatts that resources in this ELCC Class have available to produce electricity or to refill their storage component.
- Ordinary Water Storage and Exigent Water Storage capability for each month in megawatt-hours. These monthly values determine the monthly maximum amount of megawatt-hours that each resource in the ELCC class can store in the model.
- Any cascading relationship to Hydropower with Non-Pumped Storage plants on the same river system in megawatts. In the model, water discharges from upstream hydro plants with cascading relationships will be available to downstream hydro plants for generation or storage. Also, the number of hours that the upstream water discharges take to arrive to the downstream plant is required as input.

LOLP Model

Figure 8. LOLP Model Overview



The LOLP model can be subdivided in three separate sub-processes as shown in **Figure 8**: i) the Weekly Planned and Maintenance Outage Scheduler, which schedules those outages on a weekly basis based on each load scenario, ii) the Hourly Dispatch Module, which dispatches hour by hour all the resources in the system to meet load in each load scenario, and iii) the Metrics Calculator, which calculates LOLE and EUE after all the load scenarios have been analyzed.

Weekly Planned and Maintenance Outage Scheduler

As its name indicates, the Weekly Planned and Maintenance Outage Scheduler uses the hourly load scenarios for the entire RTO and an estimated IRM value to develop the planned and maintenance outage schedule. The hourly load scenarios are converted to megawatt values (instead of being per-unitized) by multiplying the per-unitized values by the forecasted 50/50 annual peak. Note that this conversion is done using the forecasted 50/50 annual peak instead of a Candidate 50/50 Forecasted Peak Load, as the resulting schedule is not very sensitive to the choice of 50/50 annual peak load being used. The estimated IRM value (which could be the one calculated the previous time the model was run) is required because the objective of the scheduler is to levelize weekly installed reserves within each load scenario, and therefore, an estimated ICAP value must be calculated [the forecasted 50/50 annual peak * (1 + estimated IRM)]. The levelization process is accomplished by choosing a schedule that minimizes the sum of the square differences between the installed reserve percent for each week and the minimum of the 52 weekly installed reserve percent values. The installed reserve percent values are calculated with respect to the corresponding weekly peak load values. The following steps describe the scheduler.

1. For each load scenario in megawatts:
    a. Initialize maintenance schedule for load scenario with 0 MW for all weeks.
    b. For each week in load scenario:
        i. Determine weekly peak load.
        ii. Determine total estimated ICAP reserves as estimated ICAP minus weekly peak load.
    c. For each unit in Unlimited Classes (sorted from unit with greatest MW*week/year maintenance requirement to lowest):
        i. Based on the number of planned/maintenance outages required R, determine the number of ways in which the R weeks can be scheduled contiguously in the Delivery Year (in general this will be 52 – R – 1).
        ii. For each of the 52 – R – 1 ways in which the R weeks can be scheduled:
            1. For each week in load scenario:
                a. Determine updated estimated ICAP reserves after scheduling planned and maintenance outages of current unit as share of weekly peak load.
            2. Determine the minimum weekly updated estimated ICAP reserves.
            3. For each week in load scenario:
                a. Calculate the square difference of the updated estimated ICAP reserves as share of weekly peak load and the minimum weekly updated estimated ICAP reserves as share of weekly peak load.
            4. Calculate the sum of the square differences across the 52 weeks.
        iii. The way to schedule the R weeks for the current unit is the one with the lowest sum of the square differences across the 52 weeks.
        iv. Update the weekly total estimated ICAP reserves based on the previous step.
        v. Update the maintenance schedule based on the decision for the current unit.

In addition to the planned and maintenance outages scheduled by the above reserve-levelizing heuristic, which results in most planned and maintenance outages scheduled during periods of lower loads, the model includes planned and maintenance outages intentionally scheduled to take place during high-risk periods. This step is taken to at least replicate planned and maintenance outage patterns observed during past historical events that have posed risk to the PJM system. **Table 20** shows the historical days as well as the level of planned and maintenance outages scheduled in the 2026 RRS.

Table 20. Planned and Maintenance Outage Scheduled During High-Risk Periods

Load Scenarios derived with weather data from DY	Season	Historical Planned/Maintenance Peak Seasonal Pattern replicated	Percent of Unlimited Installed Capacity On Planned/Maintenance Outage during Season's peak week
1993	Summer	Summer 2013	1.4%
1993	Winter	Polar Vortex 1	0.8%
1995	Summer	Summer 2013	1.4%
1995	Winter	Polar Vortex 1	0.8%
1996	Winter	Polar Vortex 2	4.1%
2001	Summer	Summer 2012	0.7%
2004	Winter	Polar Vortex 2	4.1%
2006	Summer	Summer 2012	0.7%
2010	Summer	Summer 2012	0.7%
2011	Summer	Summer 2012	0.7%
2012	Summer	Summer 2012	0.7%
2013	Summer	Summer 2013	1.4%
2013	Winter	Polar Vortex 1	0.8%
2014	Winter	Polar Vortex 2	4.1%
2022	Winter	Winter Storm Elliott	2.4%

If the reserve-levelizing heuristic schedules planned and maintenance outages in the peak week of the combination Delivery Year/season shown in the first two columns of **Table 20** that are less than the level shown in the far-right column, then the heuristic value is overwritten by the value in the far-right column. For example, using the first row of **Table 20**, if the heuristic produces planned and maintenance outages that are less than 1.4% of the total ICAP of Unlimited Resources during the summer peak week of the 13 scenarios associated with weather from Delivery Year 2013, then the quantity of outages in the summer peak weeks is set to 1.4% of the total ICAP of Unlimited Resources (if that is not the case, then the results from the heuristic are kept).

Hourly Dispatch Module

This module is the core of the LOLP model, as it determines the difference between total available supply and total demand for each hour, in each load scenario. Furthermore, the module identifies if an hour is flagged as a loss of load hour or if it does not. Finally, for resources that require "charging" (such as Limited Duration Resources and Combination Resources), this module also handles the decision to allow that charging to take place in an hour.

As shown above in **Figure 5**, this module requires a candidate solved load as an input since the 50/50 Forecasted Load that the resource portfolio (an input to the model) can serve while meeting the Reliability Criteria is unknown. These candidate solved loads are iteratively processed until the model finds the one that meets the Reliability Criteria.

Overall, the hourly dispatch module first determines the load value for the hour and then the available supply for the hour. The determination of available supply has roughly two steps: i) determining the megawatts available from Unlimited Resources, Variable Resource and the Variable Resource Component of Combination Resources and ii) if additional supply is needed for the hour, dispatching the rest of the resources in the following order

- Demand Resources
- 10-hour Storage
- 8-hour Storage
- 6-hour Storage
- 4-hour Storage
- Hydropower with Non-Pumped Storage
- Solar-Storage (4-hour) Hybrids Open-Loop
- Solar-Storage (4-hour) Hybrids Closed-Loop
- 4-hour Storage

The above order seeks to rank classes from "more available" to "less available", until the hourly load is met or a loss of load event occurs in the simulation.

Also, note that the hourly dispatch module also determines the hourly charging for Limited Duration Resources and Limited Duration Components in Combination Resources.

The following steps describe in detail the hourly dispatch module when a candidate solved load is input into the module[4].

1. For each load scenario (1 to 416) in per-unitized terms:
    a. For each hour h in the load scenario (1 to 8,760):
        i. Make a random draw α from a normal distribution with mean 0 and standard deviation equal to 1.1% to determine forecast error applied to hourly loads (this draw is made daily).
        ii. Determine the modeled hourly load as the original per-unitized load times the Candidate Solved Load times (1 + α).
        iii. Determine temperature bin B that contains historical day D in which hour h is located.
        iv. For each Resource Performance Scenario r (1 to 100):

[4] Pseudo-code is provided in Appendix 1

1. Make a random draw of a day β from temperature bin B to determine historical performance that is used in the resource performance scenario r.
2. For each class c in Unlimited Resources:
    a. Determine the total amount of ICAP in each class c that is available (not on a forced outage or ambient derate) based on the forced outages and ambient derates in the corresponding hour in historical day β.
3. Determine the total amount of available Unlimited Resources in hour h by adding up all the available megawatts for each class c in previous step and subtracting the amount of planned and maintenance outages scheduled in the week of load scenarios that contains h (this amount is provided by the Weekly Planned and Maintenance Outage Scheduler).
4. For each resource v in Variable Resources classes:
    a. If v is not in Hydropower Intermittent class:
        i. Determine the total amount of the ENC (for wind and solar classes) and ICAP (for Landfill Intermittent) that is available by using the availability data in the corresponding hour in historical day β.
        ii. Cap the value from the previous step at the corresponding deliverability caps.
    b. Else if v is in Hydropower Intermittent class:
        i. Based on the Delivery Year underlying load scenario s, determine the most similar Delivery Year Y in the period 2012–2023 (based on seasonal peak loads from the corresponding A scenarios). Then use the total amount of ICAP that is available by using the availability data at hour h in Delivery Year Y.
        ii. Cap the value from the previous step at the corresponding deliverability caps.
5. Determine the total amount of available Variable Resources in hour h by adding up all the available megawatts for each resource v in previous step.
6. Add up the total amount of available Unlimited Resources and the total amount of available Variable Resources in hour h.
7. Determine the current supply/demand margin by subtracting the modeled hourly load from the value calculated in the previous step.
8. For each unit in the Hydropower with Non-Pumped Storage class, determine if the storage component needs to be refilled and use hourly streamflow data to refill. The refilling need is calculated as the difference between the storage megawatt-hour capacity and the current megawatt-hour state. Update state of storage and determine if

there are excess megawatts due to storage being full (this will occur if the streamflow is greater than the refilling need). Note that historical streamflow data from Delivery Year Y in hour h is used, where Y is the most similar Delivery Year in the period 2012–2024 to the Delivery Year that underlies load scenario s (based on seasonal peak loads from the respective A scenarios).

9. Update the current supply/demand margin by adding: i) the minimum outputs and excess megawatts from units in the Hydropower with Non-Pumped Storage class and ii) the output of the variable component in the units in the Open-Loop Combination Resources classes.

10. If current supply/demand margin in the hour is greater than 0:

    a. Set LOLE flag for the hour equal to 0 (and the EUE value equal to 0).

    b. Determine the recharge needs of the Limited Duration Component in units in the Closed Loop Combination Resources. If there is need, proceed to recharge based on available output in the Variable Resource Component (modeled output follows the same methodology as Variable Resources with the exception that hourly availability is not capped), update storage component state of charge. If there is no need (or if there is leftover available output in the Variable Resource component), update the current supply/demand margin by adding the available output of the Variable Resource Components.

    c. Determine the total recharge need within the Limited Duration classes and the Limited Duration Component in the units in the Open Loop Combination Resources. The recharge need is the total storage capability in megawatt-hours minus the current state of charge of the resources in the respective class. Note that the recharge need of a unit in an hour is capped at ICAP x (1-EFOrd).

    d. Determine the ratio: current supply/demand margin to total recharge need from previous step.

    e. If ratio is greater than or equal to 1, proceed to fully recharge, update storage component state of charge. If ratio is less than 1, multiply the individual recharge needs by the ratio, and the result is the partial recharge allowed for each class. Update storage component state of charge.

    f. Continue with next hour.

11. If current supply/demand margin in the hour is less than 0:

    a. Compare the current supply/demand margin with the amount of available Demand Resources in the hour.

    b. If the amount of Demand Resources in the hour is greater than or equal to the current supply/demand margin, set the amount of dispatched Demand Resources

to the current supply/demand margin value. Set current supply/demand margin equal to zero. Set the LOLE flag for the hour equal to 0 (and the EUE value equal to 0).

c. If the amount of Demand Resources in the hour is less than the current supply/demand margin:

   i. Set the amount of dispatched Demand Resources to the amount of available Demand Resources in the hour. Update current supply/demand margin reduced by the amount of dispatched DR.

   ii. For each class/resource in the sorted list of Limited Duration and Combination Resources classes:

      1. If total available output of resources in class, capped at ICAP x (1-EFOrd), is greater than the current supply/demand margin. The available megawatts are impacted by the storage component state of charge, and: i) in the case of Hydropower with Non-Pumped Storage by the minimum outputs and excess megawatts from units in the class in the hour and ii) in the case of Combination Resources by the available output of the Variable Resource components.

         a. Set class output equal to current supply/demand margin.

         b. Update storage component state.

         c. Set current supply/demand margin equal to zero. Set the LOLE flag for the hour equal to 0 (and the EUE value equal to 0).

         d. Exit For Loop as there is no need to continue dispatching the other classes.

      2. Else, if total available output of resources in class, capped at ICAP x (1-EFORd), is less than the current supply/demand:

         a. Set class output equal to total available output of resources in class.

         b. Update storage component state.

         c. Update current supply/demand margin.

         d. Continue with next class/resource in the sorted list of Limited Duration and Combination Resources classes.

         e. If there are no more class/resource in the sorted list of Limited Duration and Combination Resources classes:

i. Set the LOLE flag for the hour equal to 1 (and the EUE value equal to current supply/demand margin).

iii. Continue with next hour.

Metrics Calculator

After the Hourly Dispatch Module has completed going over all the hours in the load scenarios and resource performance scenarios, the module will output a matrix with 8,760 rows and 32 x 13 x 100 (41,600) columns with LOLE flag values and a matrix with the same dimensions filled with EUE values. **Table 21** shows a schematic of the LOLE matrix.

Table 21. Example of Hourly LOLE Matrix

Hour	Load Scenario 1 – Resource Performance Scenario 1	…	Load Scenario 1 – Resource Performance Scenario 100	…	Load Scenario 416 – Resource Performance Scenario 1	…	Load Scenario 416 – Resource Performance Scenario 100
1	0	…	1	…	0	…	1
2	0	…	1	…	0	…	0
3	0	…	0	…	1	…	0
…	…	…	…	…	…	…	…
8,760	0	…	0	…	1	…	1
Total days with any loss of load (days/year)	0	…	5	…	1	…	10

The calculation of the LOLE is performed by using the values in the matrix above. First, the 8,760 values in each of the columns are grouped in days (group of 24 values). If any of the 24 values is a 1 (i.e., if any hour of the day had loss of load), the counter of days with loss of load for the scenario is increased. The maximum amount that the counter can take in a scenario is 365 (i.e., every day of the year had at least one hour with loss of load) while the minimum is 0 (i.e., no hour with loss of load was observed in the scenario). The output of the LOLE counter for each scenario is illustrated by the bottom row in **Table 21**.

Each of the scenarios is weighted equally in PJM's model. Therefore, the LOLE of the system is calculated as the average of the LOLE counter values. Because the counter for each scenario is in days/year, the average value (i.e., LOLE of the system) will also be in terms of days/year.

Table 22 shows a schematic of the EUE matrix.

Table 22. Example of Hourly EUE Matrix

Hour	Load Scenario 1 – Resource Performance Scenario 1	…	Load Scenario 1 – Resource Performance Scenario 100	…	Load Scenario 416 – Resource Performance Scenario 1	…	Load Scenario 416 – Resource Performance Scenario 100
1	0	…	100	…	0	…	15,000
2	0	…	2,500	…	0	…	0
3	0	…	0	…	1,000	…	0
…	…	…	…	…	…	…	…
8760	0	…	0	…	2,000	…	4,500
Total EUE (MWh/year)	0	…	10,000	…	5,000	…	25,000

The calculation of the EUE is performed by using the values in the matrix above. The EUE of each scenario is the sum of the EUE observed in each of the hours in the scenario. The output of the EUE counter for each scenario is illustrated by the bottom row in **Table 22**. As mentioned above, each of the scenarios is weighted equally in PJM's model. Therefore, the EUE of the system is calculated as the average of the EUE counter values. Because the counter for each scenario is in megawatt-hours/year, the average value (i.e., EUE of the system) will also be in terms of megawatt-hours/year.

A final step in the calculation of the EUE, required because the RTO-EUE is an input to the calculation of the Capacity Emergency Transfer Objective (CETO) for Locational Deliverability Areas, is to adjust the EUE value calculated using the 50/50 Solved Peak Load. This adjustment is needed because the 50/50 Solved Peak Load is likely to be different from the Forecast Peak Load for a future Delivery Year. Therefore, to account for this difference, the EUE value calculated using the 50/50 Solved Peak Load is divided by the ratio of 50/50 Solved Peak Load to Forecast Peak Load.

Capacity Benefit of Ties (CBOT)

The Capacity Benefit of Ties (CBOT) represents the external emergency assistance that PJM relies on in the Installed Reserve Margin calculation. In the current model, the CBOT is an administratively set value to the IRM Calculation. In the 2026 RRS, the CBOT value was set at 1.5% of the 50/50 peak load. This value has remained constant for several years now. Effectively, the IRM would be 1.5 percentage points higher if the CBOT were set to zero.

IRM Calculation

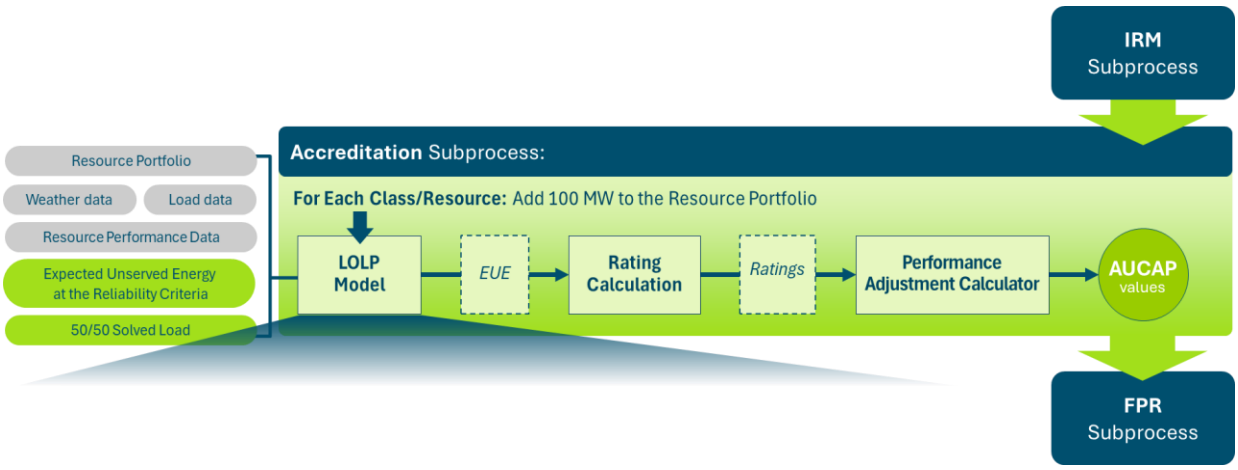
The IRM Calculation is the final step in the IRM Subprocess. This calculation uses the 50/50 Solved Peak Load output by the LOLP Model, the total ICAP in the resource portfolio, and the administratively set CBOT as follows to determine the IRM which expressed as a percentage:

Equation 1

$$IRM = \left(\frac{Total\ ICAP\ in\ Resource\ Portfolio}{\frac{50}{50} Solved\ Peak\ Load} - 1 \right) - CBOT$$

Accreditation Subprocess

Figure 9. Accreditation Subprocess Overview



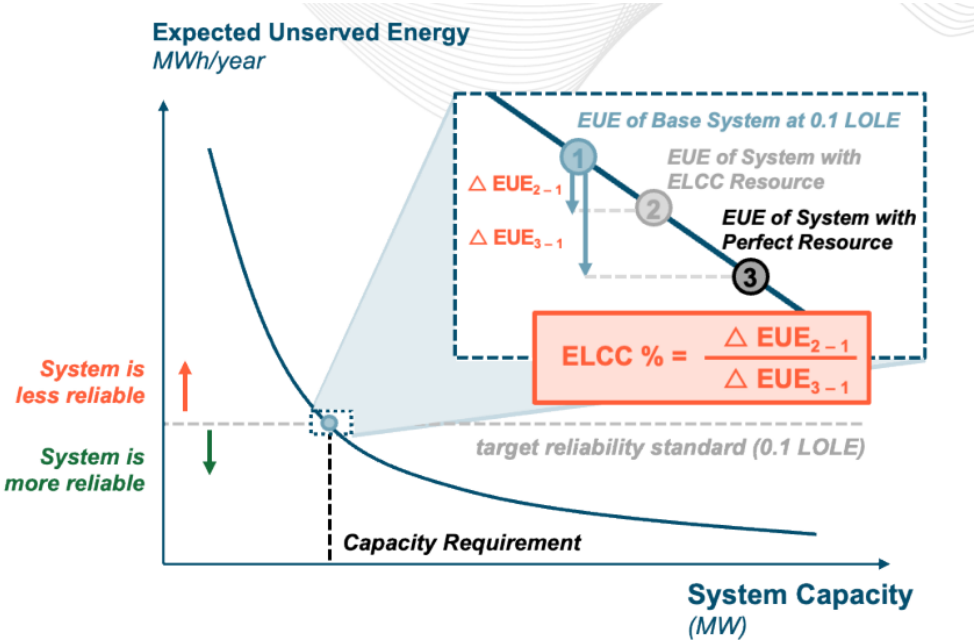
The Accreditation Subprocess requires inputs that are also inputs to the IRM Subprocess (e.g., Resource Portfolio) and outputs of the IRM Subprocess (50/50 Solved Peak Load and EUE at reliability criteria), as shown in **Figure 9**. The ELCC Accreditation Model then outputs the Accredited UCAP Values, which are key inputs into the FPR Subprocess.

This ELCC Accreditation Model has two different components: i) ELCC Class Ratings and Resource-Specific ELCC values are determined using the LOLP model followed by, ii) the calculation of a Performance Adjustment Factor for resources belonging to an ELCC Class for which an ELCC Class Rating is calculated.

LOLP Model and ELCC Class Ratings and Resource-Specific ELCC Values

ELCC Class ratings and Resource-Specific ELCC Values are based on incremental improvement of the EUE in the system compared against the incremental improvement determined by adding perfect capacity. In order to get the EUE in the applicable run, the LOLP model is run utilizing the same resource portfolio as the IRM run with one exception of adding an incremental quantity of 100 megawatts to the applicable ELCC Class/resource being run. The marginal benefit of each run is then determined based on the delta between the EUE in the applicable run versus the EUE in the IRM run (i.e., the run at the reliability criteria) as shown in **Figure 10**.

Figure 10. Determination of Marginal EUE Benefit Example



Perfect Capacity Run

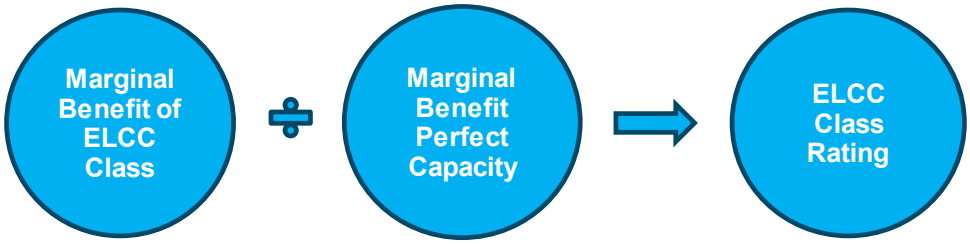
Perfect capacity is represented in the model by adding 100 megawatts ICAP of an Unlimited Resource with no outages to the resource portfolio so that anytime it is needed it provides the full 100 megawatt output. The addition of this perfect capacity will result in a new EUE value, which is then compared against the RTO EUE to determine the incremental benefit or, more specifically, the reduction in EUE due to adding this perfect capacity.

ELCC Class Run

The ELCC class run is used to determine the Class Ratings portion of accreditation and is conducted for each ELCC Class[5] separately. Each class run determines the reduction in EUE that results from adding 100 megawatt ICAP (or ENC, as applicable) of the ELCC Class. The 100 megawatt addition of the applicable ELCC Class is modeled with no adjustments to the availability rates used in the IRM run to calculate the RTO EUE (i.e., if in a given hour an ELCC Class was modeled as being 40% available in the IRM run, then in that hour only 40 megawatt of the 100 megawatt added will be modeled as available). The reduction in EUE after adding the 100 megawatt constitutes the marginal benefit of the ELCC Class, which is then compared against the marginal benefit of the perfect capacity run to ultimately determine the Class Rating as the ratio between the two. The equation to determine class ratings is shown in **Figure 11**.

[5] No ELCC Class Rating is determined for Combination Resources and ELCC Resources in the Hydropower with Non-Pumped Storage Class, in the Complex Hybrid Class, in the Other Unlimited Resource Class, and in any ELCC Class whose members are so distinct from one another that a single ELCC Class Rating would fail to capture their physical characteristics.

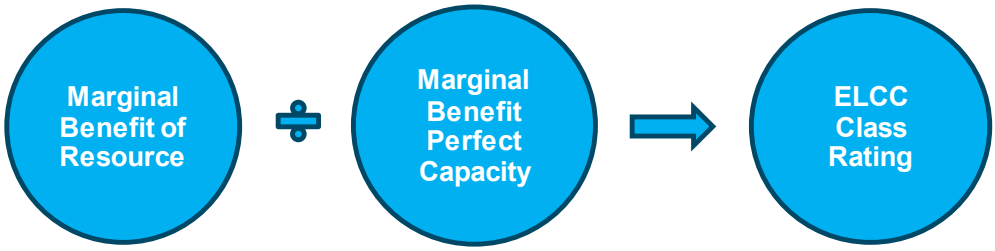
Figure 11. Equation to Determine Class Ratings



Resource-Specific Run

Resources that belong to an ELCC Class where no ELCC Class Rating is determined will receive a resource-specific ELCC value. This value is calculated by determining the benefit of adding 100 megawatt ICAP of the specific resource being evaluated. The 100 megawatt addition of the applicable resource is modeled with no adjustments to the availability rates used in the IRM run to calculate the RTO EUE. The reduction in EUE after adding the 100 megawatt constitutes the marginal benefit of the ELCC resource, which is then compared against the marginal benefit of the perfect capacity run to ultimately determine the Class Rating as the ratio between the two. The equation to determine resource-specific ratings is shown in **Figure 12**.

Figure 12. Equation to Determine Resource-Specific Ratings



ELCC Resource Performance Adjustment

Each resource belonging to a class that received an ELCC Class Rating, as described above, has an ELCC Resource Performance Adjustment factor calculated to allocate their share of the ELCC Class's total Accredited UCAP. This factor is based on the resources' average historical performance relative to the average performance of the class during hours and weather conditions (temperature bins) in which the system experienced loss of load in the IRM run.

In order to calculate this factor, the average availability across all observations in that hour and temperature bin are used to determine the resource's average availability. Next, the class's average availability is calculated by taking the average availability across all observations in that hour and temperature bin for all resources in that class. The relative risk-weighting of each hour and bin is calculated as a share of the total risk. This weighted risk is then applied to both the resource's average availability and the class's average availability across all hours and bins, which are then summed up to determine the weighted average resource availability and weighted average class availability, respectively. Lastly, the weighted average resource availability is divided by the weighted average class availability to

determine the ELCC Resource Performance Adjustment. **Figure 13** provides a schematic of the Performance Adjustment calculation.

Figure 13. Example Performance Adjustment Calculation

Bin b	Hour of day h	Weight R_{bh}	Unit's average availability A_{ubh}	Class's average availability A_{cbh}
winter1	1	0	0.98	0.80
winter1	**2**	**0.3**	**0.95**	**1.00**
winter1	**3**	**0.2**	**0.95**	**0.89**
⋮	⋮	⋮	⋮	⋮
winter1	24	0	0.84	0.99
winter2	1	0	0.89	0.91
winter2	**2**	**0.2**	**0.98**	**0.81**
winter2	3	0	0.95	0.90
⋮	⋮	⋮	⋮	⋮
winter2	24	0	0.92	0.99
winter3	1	0	0.88	0.87
winter3	2	0	0.85	0.90
winter3	3	0	0.96	0.95
⋮	⋮	⋮	⋮	⋮
winter3	24	0	0.94	0.96
⋮	⋮	⋮	⋮	⋮
summer34	1	0	0.98	0.89
summer34	2	0	0.96	0.89
summer34	**3**	**0.3**	**0.99**	**0.96**
⋮	⋮	⋮	⋮	⋮
summer34	24	0	0.95	0.94
Weighted Averages			0.97	0.93
Resource Performance Adjustment				**1.04**

Computation Reference:

- For each temperature bin *(b)* & hour of day *(h)*:
  - Unit's *(u)* average availability across all observations in that bin & hour: A_{ubh}
  - Class's *(c)* average availability across all observations in that bin & hour: A_{cbh}
  - Relative risk weighting of the bin & hour (as a share of total risk): R_{bh}
- Weighted average of unit availability across all bin/hour pairs:

$$A_u = \sum_{b,h} R_{bh} \cdot A_{ubh}$$

- Weighted average of class availability across all bin/hour pairs:

$$A_c = \sum_{b,h} R_{bh} \cdot A_{cbh}$$

- Resource Performance Adjustment: $\frac{A_u}{A_c}$

Accredited UCAP and Accredited UCAP Factor

Accredited UCAP is the quantity of unforced capacity that an ELCC Resource can provide in a given Delivery Year.[6]

For resources that belong to an ELCC Class that has an ELCC Class Rating published, the Accredited UCAP calculation is shown in **Table 23**.

Table 23. Accredited UCAP Calculation for Resource's Belonging to a Class with a Published Class Rating

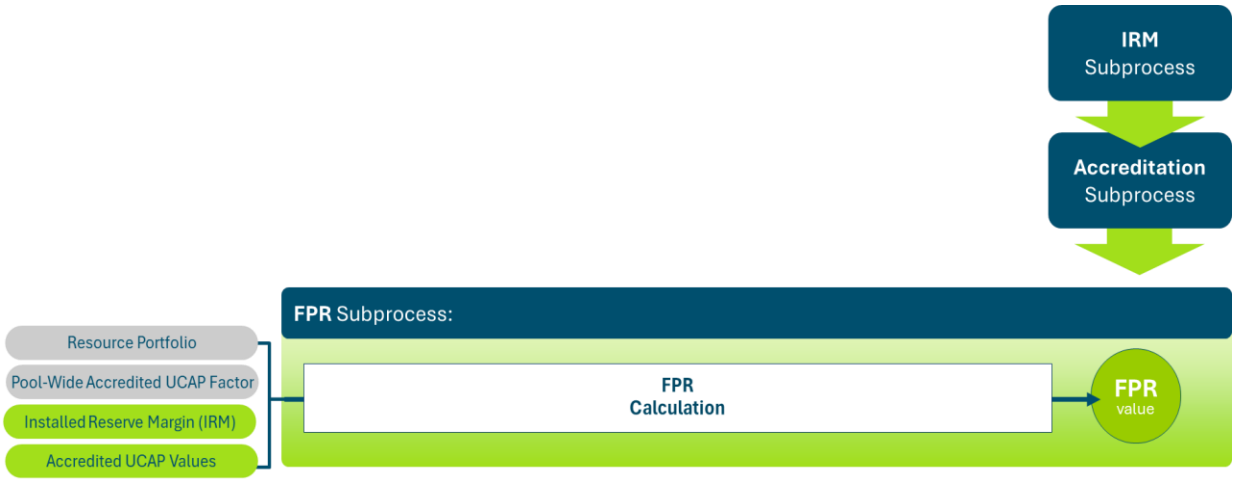
Resource Type	Accredited UCAP Calculation
Variable and Limited Duration Resources	Effective Nameplate Capacity x ELCC Class Rating x ELCC Resource Performance Adjustment
Unlimited Resources	Installed Capacity (ICAP) x ELCC Class Rating x ELCC Resource Performance Adjustment
Demand Resource	Nominated ICAP x ELCC Class Rating

[6] Accredited UCAP cannot exceed the resource's Capacity Interconnection Rights including any transitional deliverability or winter CIRs awarded for the applicable time period.

For resources that belong to an ELCC Class for which no ELCC Class Rating has been determined, the Accredited UCAP shall be based on a resource-specific ELCC value based on the resource's unique parameters as discussed above.

FPR Subprocess

Figure 14. FPR Subprocess Overview



As shown in **Figure 14**, the FPR Subprocess requires inputs that are outputs of the IRM Subprocess (i.e., IRM) and the Accreditation Subprocess (i.e., AUCAP Values) as well as the Resource Portfolio (also an input to the IRM Subprocess).

FPR Calculation

The Forecast Pool Requirement (FPR) can be viewed as the equivalent of the IRM in Accredited UCAP terms. In other words, if the IRM is the requirement in units of Installed Capacity to meet the RTO Reliability Criteria, the FPR is the requirement in units of Accredited Unforced Capacity (UCAP). As such, the mathematical formula to derive the FPR depends on the IRM and a factor that converts the total ICAP in the Resource Portfolio to total Accredited UCAP. That factor is the pool-wide Average Accredited UCAP Factor. This factor can be interpreted as the ELCC rating that the overall resource portfolio receives. Therefore,

Equation 2

$$FPR = (1 + IRM)\ x\ pool - wide\ average\ Accredited\ UCAP\ Factor$$

Where the pool-wide Accredited UCAP Factor is calculated as:

Equation 3

$$pool - wide\ average\ Accredited\ UCAP\ Factor = \frac{Total\ AUCAP\ in\ Resource\ Portfolio}{Total\ ICAP\ in\ Resource\ Portfolio}$$

Discussion of Results

Delivery Years 2028/2029 and 2029/2030

Table 24 shows value for key inputs and outputs for Delivery Years 2028/2029 and DY 2029/2030. The values included in this report for those two Delivery Years are official values used in RPM activities. The results for the rest of the Delivery Years included in this report are explained separately and are informational only.

Table 24. Reliability Metrics for the 2028/2029 and 2029/2030 Delivery Years

DY	Total ICAP in Resource Portfolio (MW)	50/50 Solved Peak Load (MW)	CBOT (%)	IRM (%)	Total AUCAP in Resource Portfolio (MW)	Pool Wide Avg AUCAP Factor	FPR
2028/2029	196,871	162,063	1.5	20.0	154,234	0.7834	0.9401
2029/2030	203,004	166,521	1.5	20.4	155,663	0.7668	0.9232

Table 25 shows the ELCC Class Ratings for DY 2028/2029 and DY 2029/2030 as well as the EUE values resulting from adding an incremental quantity of each class ("EUE in ELCC Class Run") and the EUE reduction in each case, which is calculated relative to the EUE resulting from the 1 in 10 cases (1,793.5 MWh/year in 2028/2029 and 2,183.7 MWh/year in 2029/2030). The ratings for each ELCC Class are calculated by dividing the corresponding EUE reduction by the EUE reduction generated by adding an incremental quantity of Perfect Capacity (shown in first row of **Table 25**).

Table 25. Class Ratings for the 2028/2029 and 2029/2030 Delivery Years

ELCC Class	2028/2029 EUE in ELCC Class Run	2028/2029 EUE Reduction	2028/2029 Rating	2029/2030 EUE in ELCC Class Run	2029/2030 EUE Reduction	2029/2030 Rating
Perfect Capacity	1,752.51	40.99	100%	2,138.41	45.29	100%
Onshore Wind	1,779.42	14.08	34%	2,166.83	16.87	37%
Offshore Wind	1,768.85	24.65	60%	2,154.45	29.25	65%
Fixed-Tilt Solar	1,790.55	2.95	7%	2,180.87	2.83	6%
Tracking Solar	1,789.47	4.03	10%	2,180.33	3.37	7%
Intermittent Landfill Gas	1,773.05	20.45	50%	2,161.15	22.55	50%
Intermittent Hydropower	1,779.23	14.27	35%	2,168.13	15.57	34%
Capacity Storage Resource (4-hr)	1,769.14	24.36	59%	2,158.08	25.62	57%
Capacity Storage Resource (6-hr)	1,765.81	27.69	68%	2,153.67	30.03	66%
Capacity Storage Resource (8-hr)	1,764.6	28.9	71%	2,152.5	31.2	69%
Capacity Storage Resource (10-hr)	1,761.36	32.14	78%	2,149.12	34.58	76%
Demand Resource	1,756.04	37.46	91%	2,143.15	40.55	90%
Coal	1,758.68	34.82	85%	2,145.53	38.17	84%
Diesel Utility	1,755.45	38.05	93%	2,142.02	41.68	92%

ELCC Class	2028/2029 EUE in ELCC Class Run	2028/2029 EUE Reduction	2028/2029 Rating	2029/2030 EUE in ELCC Class Run	2029/2030 EUE Reduction	2029/2030 Rating
Gas Combined Cycle	1,761.49	32.01	78%	2,149.95	33.75	75%
Gas Combustion Turbine	1,766.09	27.41	67%	2,156.91	26.79	59%
Gas Combustion Turbine Dual Fuel	1,760.95	32.55	79%	2,149.36	34.34	76%
Nuclear	1,754.22	39.28	96%	2,140.37	43.33	96%
Steam	1,762.69	30.81	75%	2,149.62	34.08	75%
Waste to Energy Steam	1,759.1	34.4	84%	2,146.24	37.46	83%
Oil-Fired Combustion Turbine	1,759.41	34.09	83%	2,147.06	36.64	81%

PJM's study is performed analyzing an entire delivery year. To understand output values such as the Pool Wide Avg AUCAP Factor, FPR and the ELCC Class Ratings, it is useful to identify the annual value for the calculated reliability metrics and their seasonal split.

Table 26. Seasonal Resource Adequacy Metrics for 2028/2029 and 2029/2030 Delivery Years

Metric	2028/2029 Annual Value	2028/2029 Summer Share (%)	2028/2029 Winter Share (%)	2029/2030 Annual Value	2029/2030 Summer Share (%)	2029/2030 Winter Share (%)
LOLE (day/year)	0.1	39.5%	60.5%	0.1	22.1%	77.9%
LOLH (hours/year)	0.348	23.4%	76.6%	0.377	10.6%	89.4%
EUE (MWh/year)	1,793.5	9.8%	90.2%	2,183.7	3.7%	96.3%

As shown in **Table 26**, the annual LOLE value is 0.1 days/year in both Delivery Years (this is by design as this value is the RTO-wide resource adequacy criteria). The LOLE seasonal split for both Delivery Years shows that much of the LOLE is in the winter season, with the winter share increasing in the 2029/2030 Delivery Year compared to the 2028/2029 Delivery Year. The other two metrics, LOLH and EUE, are higher in the 2029/2030 Delivery Year than in the 2028/2029 Delivery Year, but both metrics in both Delivery Years show a marked winter slant, with increasing winter shares in the 2029/2030 Delivery Year compared to the 2028/2029 Delivery Year.

To understand these results, the focus should be on analyzing the inputs to the model.

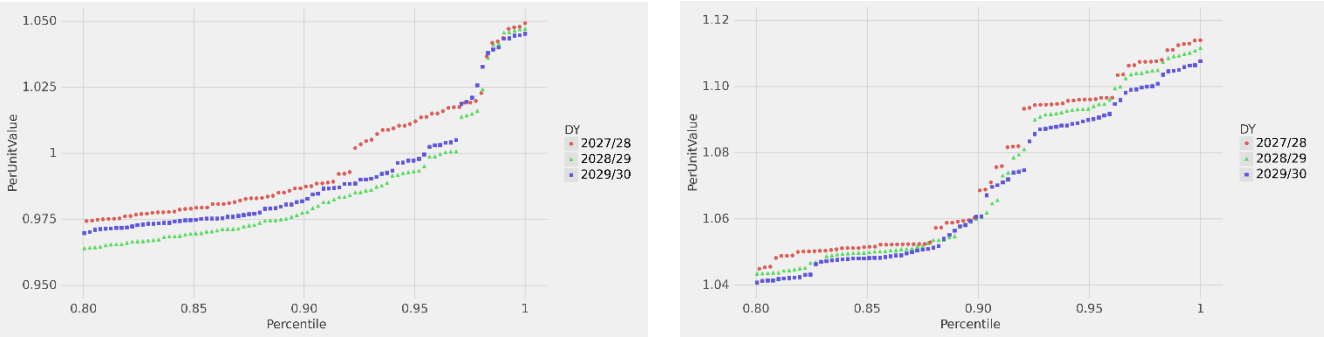
Inputs

Differences in the inputs on both the demand and supply side have an impact on the model and thus impact the results. First, we will discuss changes in load followed by changes to the resource portfolio and the underlying performance of the resources in that portfolio.

Load

Figure 15 shows the top 20th percentile of the winter and summer peak load cumulative distribution functions (CDF) in per-unitized values (as share of the annual peak) for both Delivery Years as well as for DY 2027/2028 from the 2025 ELCC/RRS.

Figure 15. Winter (left) and summer (right) peak load cumulative distribution functions (top 20th percentile)



The winter CDF shows that except for the very few points in the extreme of the distribution, all other winter peak load values in the top 20th percentile of the distribution are greater in magnitude in the 2027/2028 Delivery Year (that comes from the 2025 Load Forecast and 2025 ELCC/RRS). For the DYs studied in the 2026 ELCC/RRS (whose distributions come from the 2026 Load Forecast), the 2029/2030 values are greater than those in the 2028/2029 DY.

The top 20th percentile summer CDFs show that the 2027/2028 summer peak load values (from the 2025 Load Forecast) are greater than those in the other two distributions, while the 2028/2029 summer peak load values are greater than those in 2029/2030.

The winter CDF graph helps explain the reduction in winter risk observed in the 2028/2029 BRA run relative to the 2027/2028 BRA, and the subsequent increase in winter risk observed in the 2029/2030 BRA relative to the 2028/2029 BRA run. The summer CDF graph illustrates a consistent trend of lower summer peak load values (as share of the respective annual peaks) that has put downward pressure on summer risk in the 2025 RRS/ELCC and the 2026 RRS/ELCC.

Resource Performance:

The resource availability/unavailability patterns that tend to drive the loss of load risk in the model are those modeled on days in which seasonal loads are high. Therefore, to understand the higher winter risk shown in **Table 26**, the focus of this subsection is on the resource availability/unavailability patterns during such days. As described earlier in this report, historical days are grouped in bins based on THI. Since temperature is highly correlated with load, to model resource availability/unavailability patterns on days with high seasonal loads, resource availability/unavailability patterns are chosen from the coldest and hottest bins based on the weather of the relevant load scenario. For instance, Jan. 19, 1994, was a very cold day and therefore is placed in the coldest bin. As shown in Table 27**Table 27**, there are seven days post-2012 in that bin from which the modeled resource availability/unavailability patterns for days located in the coldest bin such as Jan. 19, 1994, are derived. The seven days are listed in **Table 27** as well as the seven different availability rates for the total set of Unlimited Resources modeled in the runs for the 2028/2029 and 2029/2030 Delivery Years based on historical performance of resources in the corresponding resource portfolio at hour beginning 7 a.m. from the respective days.

Table 27. Modeled Unlimited Resource Availability/Unavailability Patterns for Days Located in the Coldest Bin (Hour Beginning 7)

Historical Day in Coldest Bin from which performance pattern is derived for modeled loads with weather from 1994-01-19	2028/2029 Modeled Availability Rate for Unlimited Resources at HB 7 (before reductions due to planned and maintenance outages)	2029/2030 Modeled Availability Rate for Unlimited Resources at HB 7 (before reductions due to planned and maintenance outages)
2014-01-07	78%	77%
2014-01-22	89%	89%
2014-01-28	91%	90%
2015-01-08	92%	91%
2015-02-20	93%	92%
2019-01-30	97%	97%
2019-01-31	91%	90%

Whenever the model simulates Jan. 19, 2029 in the 2028/2029 run (or 2030 in the 2029/2030 run), under the 13 load scenarios that use weather data from Delivery Year 1993, the model makes a random draw from the seven days shown in **Table 27**. Each of the days has identical probability of being selected, 1/7 = 14.3%. When the day is randomly drawn, the entire 24-hour availability rate pattern for Unlimited Resources (before modeling reductions due to planned and maintenance outages) is derived based on the drawn day. The availability rates at 7 a.m., to be used in days in the coldest bin, range from 77% to 97% (unavailability rates ranging from 3% to 24%).

As an example of a day in the hottest bin, one of the hottest days in the last 31 years was July 21, 2011. This day is placed in the hottest bin. As shown in **Table 28**, there are 30 days post-2012 in that bin from which derives the modeled resource availability/unavailability patterns for days located in the hottest bin, such as July 21, 2011. The 30 days are listed in **Table 28** as well as the 30 different availability rates for the total set of Unlimited Resources modeled in the runs for the 2028/2029 and 2029/2030 Delivery Years based on historical performance of resources in the corresponding resource portfolio at hour beginning (HB) 18 (6 p.m.) from the respective days.

Table 28. Modeled Unlimited Resource Availability/Unavailability Patterns for Days Located in the Hottest Bin (Hour Beginning 18)

Historical Day in Hottest Bin from which performance pattern is derived for modeled loads with weather from 2011-07-21	2028/2029 Modeled Availability Rate for Unlimited Resources at HB 18 (before reductions due to planned and maintenance outages)	2029/2030 Modeled Availability Rate for Unlimited Resources at HB 18 (before reductions due to planned and maintenance outages)	Historical Day in Hottest Bin from which performance pattern is derived for modeled loads with weather from 2011-07-21	2028/2029 Modeled Availability Rate for Unlimited Resources at HB 18 (before reductions due to planned and maintenance outages)	2029/2030 Modeled Availability Rate for Unlimited Resources at HB 18 (before reductions due to planned and maintenance outages)
2012-06-29	95%	95%	**2018-06-18**	97%	97%

Historical Day in Hottest Bin from which performance pattern is derived for modeled loads with weather from 2011-07-21	2028/2029 Modeled Availability Rate for Unlimited Resources at HB 18 (before reductions due to planned and maintenance outages)	2029/2030 Modeled Availability Rate for Unlimited Resources at HB 18 (before reductions due to planned and maintenance outages)	Historical Day in Hottest Bin from which performance pattern is derived for modeled loads with weather from 2011-07-21	2028/2029 Modeled Availability Rate for Unlimited Resources at HB 18 (before reductions due to planned and maintenance outages)	2029/2030 Modeled Availability Rate for Unlimited Resources at HB 18 (before reductions due to planned and maintenance outages)
2012-07-04	97%	97%	2018-07-01	97%	98%
2012-07-06	96%	96%	2018-08-28	97%	97%
2012-07-07	95%	95%	2018-09-04	98%	98%
2012-07-17	93%	93%	2018-09-05	98%	97%
2012-07-18	92%	92%	2019-07-19	97%	97%
2012-07-26	96%	96%	2019-07-20	97%	98%
2013-07-17	95%	95%	2019-07-21	96%	97%
2013-07-18	95%	95%	2021-06-29	95%	95%
2013-07-19	95%	95%	2021-08-12	97%	97%
2016-07-23	96%	96%	2022-07-24	96%	96%
2016-07-25	95%	95%	2023-07-27	96%	96%
2016-08-11	96%	96%	2023-07-28	95%	95%
2016-08-12	96%	96%	2024-07-15	96%	96%
2016-08-13	97%	97%	2024-07-16	95%	95%

Whenever the model simulates July 21, 2028 in the 2028/2029 run (or 2029, in the 2029/2030 run), under the 13 load scenarios that use weather data from Delivery Year 2011, the model makes a random draw from the 30 days shown in **Table 28**. Each of the days has identical probability of being selected, 1/30 = 3.3%. When the day is randomly drawn, the entire 24-hour availability rate pattern for Unlimited Resources (before modeling reductions due to planned and maintenance outages) is derived based on the drawn day. The availability rates at 6 p.m., to be used in days in the hottest bin, range from 92%–98% (unavailability rates ranging from 2%– 8%).

Table 29 and **Table 30** show the corresponding values the availability of Variable Resources in the 2028/2029 and 2029/2030 Delivery Year model runs for the coldest and hottest bins at hour beginning 7 a.m. and 6 p.m., respectively.

Table 29. Modeled Variable Resource Availability/Unavailability Patterns for Days Located in the Coldest Bin (HB 7)

Historical Day in Coldest Bin from which performance pattern is derived for modeled loads with weather from 1994-01-19	2028/2029 Modeled Availability Rate for Variable Resources at HB 7	2029/2030 Modeled Availability Rate for Variable Resources at HB 7
2014-01-07	24%	23%
2014-01-22	17%	16%
2014-01-28	14%	13%
2015-01-08	22%	21%
2015-02-20	22%	22%
2019-01-30	22%	21%
2019-01-31	9%	8%

Table 30. Modeled Variable Resource Availability/Unavailability Patterns for Days Located in the Hottest Bin (Hour Beginning 18)

Historical Day in Hottest Bin from which performance pattern is derived for modeled loads with weather from 2011-07-21	2028/2029 Modeled Availability Rate for Variable Resources at HB 18	2029/2030 Modeled Availability Rate for Variable Resources at HB 18	Historical Day in Hottest Bin from which performance pattern is derived for modeled loads with weather from 2011-07-21	2028/2029 Modeled Availability Rate for Variable Resources at HB 18	2029/2030 Modeled Availability Rate for Variable Resources at HB 18
2012-06-29	23%	23%	2018-06-18	36%	35%
2012-07-04	27%	27%	2018-07-01	34%	33%
2012-07-06	30%	30%	2018-08-28	30%	29%
2012-07-07	27%	27%	2018-09-04	18%	18%
2012-07-17	33%	34%	2018-09-05	16%	16%
2012-07-18	23%	23%	2019-07-19	35%	34%
2012-07-26	28%	28%	2019-07-20	38%	37%
2013-07-17	29%	29%	2019-07-21	26%	26%
2013-07-18	30%	30%	2021-06-29	28%	28%
2013-07-19	36%	34%	2021-08-12	28%	27%
2016-07-23	30%	30%	2022-07-24	30%	29%
2016-07-25	24%	24%	2023-07-27	29%	29%
2016-08-11	25%	23%	2023-07-28	29%	28%
2016-08-12	25%	24%	2024-07-15	31%	30%
2016-08-13	21%	21%	2024-07-16	27%	26%

In the case of the coldest bin, the availability rates of Variable Resources range from 8%–9% to 23%–24%. In the case of the hottest bin, the range is from 16% to 37%–38%.

Clearly, availability rates for both Unlimited Resources and Variables Resources tend to be lower in the coldest bin compared to those in the hottest bin.

Using per-unitized load values for January 18, 2030, 7 a.m. from load scenario B1993 and for July 23, 2029, 6 p.m. from load scenario I2011 (hourly loads from days associated with the coldest and hottest bins, respectively), as well as the 50/50 Peak Solved Load for the 2029/2030 run (166,521 MW), we can get an idea of the supply/demand margin when using the worst-case availability values for Unlimited and Variable Resources from the tables above.

Table 31. Illustrative Comparison of Supply/Demand Margin for a Day in Coldest Bin and a Day in Hottest Bin

Time Stamp	Scenario	Per-Unitized Load Value x 50/50 Peak Solved Load	Total ICAP for Unlimited Resources	Total ENC for Variable Resources	Day in Respective Bin showing lowest combined availability for Unlimited and Variable Resources	Lowest combined availability for Unlimited and Variable Resources	Margin when using lowest combined availability for Unlimited and Variable Resources
January 18, 2030, 7 a.m.	B1993	1.05 x 166,521 = 174,847	163,709	45,875	2014-01-07	77% x 163709 + 23% x 45875=136607	-38,240
July 17, 2029, 6 p.m.	I2011	1.11 x 166,521 = 184,838	163,709	45,875	2012-07-18	92% x 163709 + 23% x 45875=161164	-23,674

Winter Risk vs. Summer Risk

Table 31, while not including the available DR, Limited Duration and Combination Resources, and also not accounting for the planned and maintenance outages of Unlimited Resources in the calculation of the margin, provides an illustrative insight into why the model identifies more winter risk than summer risk. The margin on January 18, 2030, 7 a.m., is significantly less than the margin on July 22, 2029, 6 p.m. This is driven mainly by the lower availability of Unlimited Resources in the day in the respective temperature bin that shows the lowest combined availability for Unlimited and Variable Resources, i.e., 77% on 2014-01-07 (for worse performance day in the coldest bin) vs. 92% on 2012-07-18 (for worse performance day in the hottest bin), which largely offsets the lower demand observed in the winter day compared to the summer day. In general, the day with the worse performance in the hottest bin (2012-07-18) is expected to be drawn more often than the day with the worse performance in the coldest bin (2014-01-07):

Expected number of days that performance from 2012-07-18 will be drawn = Number of days in the hottest bin x Probability of drawing 2012-07-18 from hottest bin = 81 x 3.3% = 2.7

Expected number of days that performance from 2014-01-07 will be drawn = Number of days in the coldest bin x Probability of drawing 2014-01-07 from coldest bin = 18 x 14.3% = 2.57

However, the difference is diminutive (2.7 vs. 2.57), and the deficit for the winter day when accounting only for Variable Resources and Unlimited Resources Availability is larger than that for the summer day as shown in **Table 30**. The implication of the latter point is that it is less likely that, during the winter day, the resources not yet

accounted for in the calculation (DR, Limited Duration and Combination Resources) will be able to bring the margin to a positive value and avoid the loss of load.

Top Performance Patterns Contributing to Loss of Load Events

Following the discussion of winter risk vs. summer risk, the resource performance patterns that drive the loss of load events in the model can be identified. In the 2028/2029 run, this can be done by analyzing the Info for Loss of Load Hours (XLS) posted file, specifically the ActualPerfDay column (for the 2029/2030 run, this is the file). **Table 32** provides the top 10 resource performance patterns that drive loss of load in the model as well as the share of the LOLH that each of them contribute for the 2028/2029 and 2029/2030 runs.

Table 32. Resource Performance Paterns that Drive Loss of Load in 2028/2029 and 2029/2030

Resource Performance Pattern	LOLH Share (2028/2029)	LOLH Share (2029/2030)
2014-01-07	38.4%	45.1%
2022-12-24	12.9%	14.4%
2014-01-08	8.8%	12.5%
2022-12-26	4.7%	4.8%
2014-01-28	3.2%	3.1%
2014-01-22	2.5%	2.4%
2019-01-31	2.4%	2.3%
2012-07-18	1.8%	0.7%
2022-12-25	0.9%	2.5%
2012-06-29	0.7%	0.3%

Given the larger share of winter risk in the three resource adequacy metrics (LOLE, LOLH, EUE) in the 2028/2029 and 2029/2030 runs, it is not surprising to see the majority of the top resource performance patterns driving risk in the model to be from winter days (there are only two summer performance pattern from 2012-07-18 and 2012-06-29). It is important to distinguish the contribution that each of these performance patterns provide to observe loss of load in the model from how often these performance patterns are simulated in the model. For example, as discussed above, the 2014-01-07 (2014 Polar Vortex) performance pattern is simulated only when a day in the coldest bin is selected (there are only 18 days in this bin in the period), and then the conditional probability of selecting the performance pattern from 2014-01-07 is 14.3%. The fact that the contribution of the 2014-01-07 in the 2028/2029 run is 38.4% means that the loss of load events that the model identifies for 2028/2029 are driven by the few times the 2014-01-07 performance pattern is simulated in the model due to the high volume of forced outages that such performance pattern includes. Other performance patterns tend to be simulated more often, such as the performance from 2012-07-18 as discussed above; however, that performance pattern does not include a high volume of forced outages and therefore its contribution to LOLH for 2028/2029 as shown in **Table 32** is only 1.8%.

Duration and Size of Daily Loss of Load Events

Figure 16 provides boxplots, by season, for 2028/2029 and 2029/2030 with the number of hours in a day that see loss of load (not necessarily contiguous hours). Note that the boxplots were calculated excluding days that did not have loss of load.

Figure 16. Seasonal Boxplots for Number of Hours in a Day with Loss of Load in 2028/2029 and 2029/2030

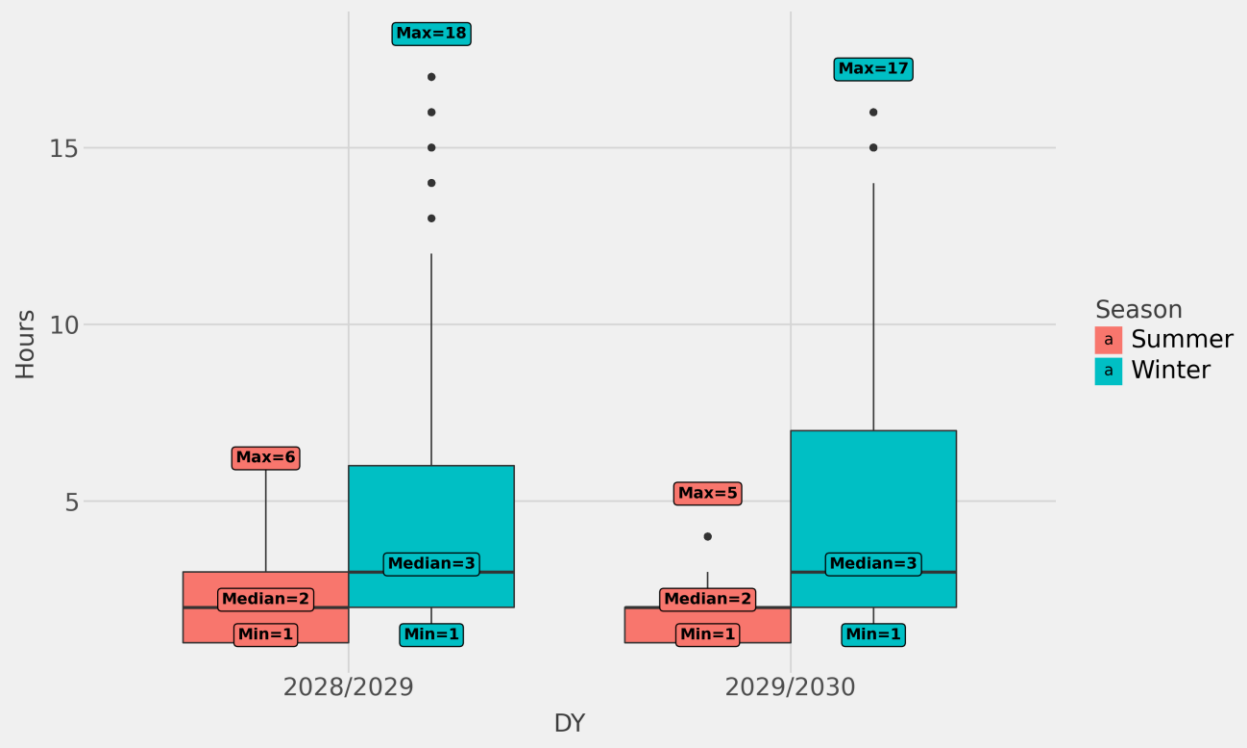
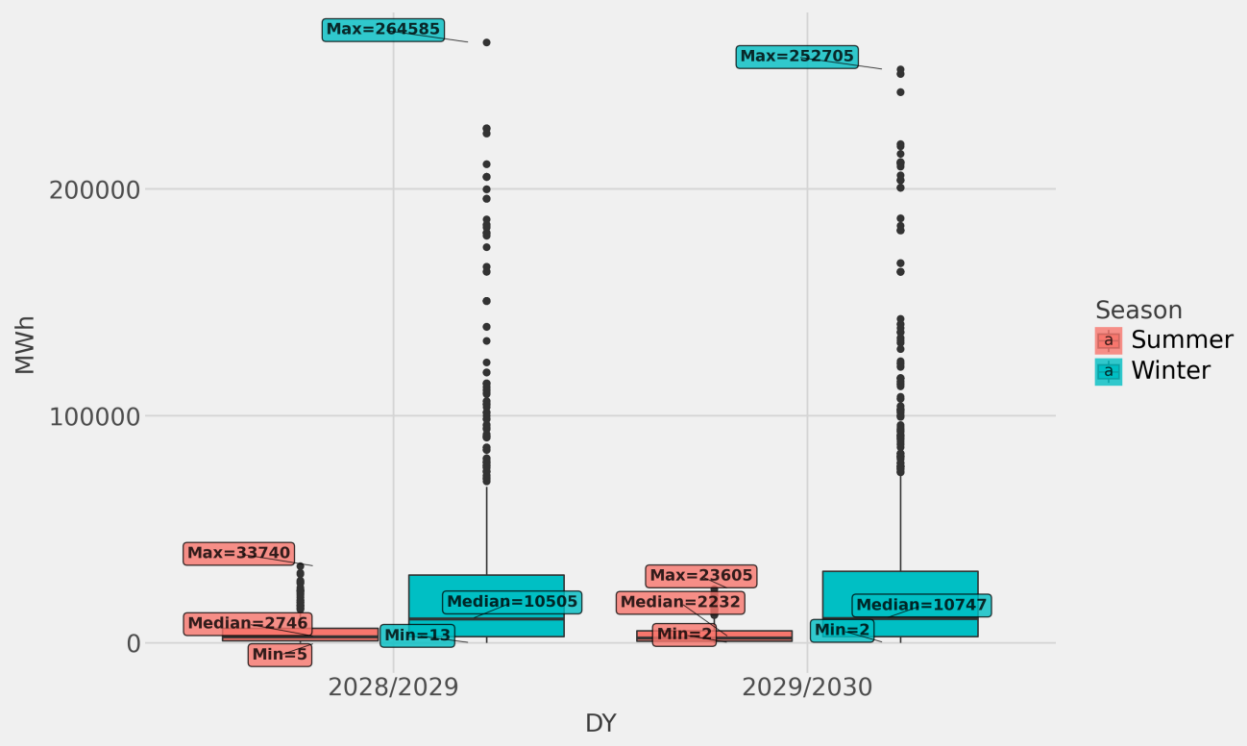


Figure 17 provides boxplots, by season, for 2028/2029 and 2029/2030 with the number of megawatt-hours in a day that go unserved (i.e., event size). Note that the boxplots were calculated excluding days that did not have loss of load.

Figure 17. Seasonal Boxplots for unserved Megawatt-hours in a Day with Loss of Load in 2028/2029 and 2029/2030



From earlier discussions, we know that the share of EUE and LOLH (as well as LOLE) in the summer is less than in the winter in the 2028/2029 and 2029/2030 runs. In addition, from **Figure 16 and Figure 17**, we can also conclude that the fewer events in summer are much milder than those events in winter: the maximum duration of an event in winter is three times worse than in summer (18 hours vs 6 hours in 2028/2029, 17 hours vs 5 hours in 2029/2030) while the maximum event size is about 8 times worse in winter in 2028/2029 (264,585 MWh vs. 33,740 MWh) and about 11 times worse in winter in 2029/2030 (252,705 MWh vs. 23,605 MWh). These seasonal differences have implications for the accreditation that resources get, especially limited duration resources as discussed later.

Seasonal Risk and ELCC Class Ratings

The larger share of winter risk in the 2028/2029 and 2029/2030 analyses explained above also drives the resulting ELCC Class Ratings shown in **Table 33**. As detailed in the Accreditation Subprocess description, resource accreditation is based on the EUE reduction that a marginal addition of a certain class/resource provides to the system relative to the EUE reduction that a marginal addition of perfect capacity provides. Intuitively, if most of the loss of load risk resides in a given season, then resources that are expected to perform better in such given season will be in a better position to provide the required EUE reduction and therefore get a higher ELCC rating.

On the above point, a 34% ELCC Class Rating in 2028/2029 for Onshore Wind and a 67% ELCC Class Rating in 2028/2029 for Gas Combustion Turbine, for example, can be roughly understood by observing that the three resource adequacy metrics (LOLE, LOLH, EUE) have larger shares in the winter season than in the summer season. Historical performance data shows that Onshore Wind resources perform better during PJM winter risk periods rather

than during PJM summer risk periods, and therefore Onshore Wind's ELCC Class Rating is increased by the fact that winter risk is predominant in the 2028/2029 run. Conversely, Gas Combustion Turbine resources have historically performed better during PJM summer risk periods rather than during PJM winter risk periods, and therefore Gas Combustion Turbine's ELCC Class Rating is decreased by the seasonal risk patterns in the 2028/2029 run.

In general, the drivers of the ELCC Class Ratings in the 2028/2029 and 2029/2030 runs can be summarized as shown in **Table 33**.

Table 33. General drivers of the ELCC Class Ratings

ELCC Class	2028/2029 Rating	2029/2030 Rating	Driver
Onshore Wind	34%	37%	Better expected performance in winter critical hours than in summer critical hours
Offshore Wind	60%	65%	Better expected performance in winter critical hours than in summer critical hours
Fixed-Tilt Solar	7%	6%	Worse expected performance in winter critical hours than in summer critical hours
Tracking Solar	`10%	7%	Worse expected performance in winter critical hours than in summer critical hour
Intermittent Landfill Gas	50%	50%	Stable performance (at rating level) across most of risk hours
Intermittent Hydropower	35%	34%	Stable performance (at rating level) across most of risk hours
Capacity Storage Resource (4-hr)	59%	57%	Longer duration of expected winter events (compared to summer events) as well as energy-constrained winter days decreases rating
Capacity Storage Resource (6-hr)	68%	66%	Longer duration of expected winter events (compared to summer events) as well as energy-constrained winter days decreases rating
Capacity Storage Resource (8-hr)	71%	69%	Longer duration of expected winter events (compared to summer events) as well as energy-constrained winter days decreases rating
Capacity Storage Resource (10-hr)	78%	76%	Longer duration of expected winter events (compared to summer events) as well as energy-constrained winter days decreases rating
Demand Resource	91%	90%	Lower DR reduction capability in winter compared to summer
Nuclear	96%	96%	Small frequency of forced outages throughout the year

ELCC Class	2028/2029 Rating	2029/2030 Rating	Driver
Coal	85%	84%	Forced outages that tend to be more frequent during winter risk hours as well as planned and maintenance outages
Gas Combined Cycle	78%	75%	Forced outages that tend to be more frequent during winter risk hours
Gas Combustion Turbine	67%	59%	Forced outages that tend to be more frequent during winter risk hours. Lower rating in 2029/2030 due to changes to class membership
Gas Combustion Turbine Dual Fuel	76%	76%	Forced outages that tend to be more frequent during winter risk hours
Diesel Utility	93%	92%	Forced outages that tend to be more frequent during winter risk hours
Steam	75%	75%	Forced outages that tend to be more frequent during winter risk hours as well as planned and maintenance outages
Waste to Energy Steam	84%	83%	Forced outages that tend to be more frequent during winter risk hours
Oil-Fired Combustion Turbine	83%	81%	Forced outages that tend to be more frequent during winter risk hours

Loss of Load Hours vs. Non-Loss of Load Hours

As described in the Accreditation Subprocess section, the accreditation of classes and resources is impacted by modeled performance during: i) loss of load hours and ii) other hours in days/periods where the system is energy constrained. The share of the accreditation that can be attributed to modeled performance during loss of load hours can be estimated by identifying the hours in which the EUE reductions resulting from adding an increment of perfect capacity occur. **Table 34** shows the share of this EUE reduction by season and by performance in loss of load hours and non-loss of load hours in the 2028/2029 Delivery Year and 2029/2030 Delivery Year runs. Consistent with what was discussed about seasonal risk shares for LOLE, LOLH and EUE, the majority of the EUE reduction when adding an increment of perfect capacity occurs in the winter, 80.1% for 2028/2029 and 91.26% for 2029/2030. Within the winter, a non-negligible share of the EUE reduction occurs during non-loss of load hours, 15.58% in 2028/2029 and 17.48% in 2029/2030, while the rest occur during loss of load hours. In summer, almost all the EUE reductions occur during loss of load hours (the share of the EUE reduction occurs during non-loss of load hours are negligible, 0.22% and 0.01%). This is because EUE reductions due to performance in non-loss of load hours are only relevant during energy-constrained periods, and such periods do not tend to occur during summer due to peakier load shapes and shorter periods of large unavailability of resources.

Table 34. 2028/2029 and 2029/2030 Delivery Year Share of EUE Reduction by Season

Season	2028/2029			2029/2030		
	Share of EUE Reduction Occurring in Loss of Load Hours	Share of EUE Reduction Occurring in Non-Loss of Load Hours	Total	Share of EUE Reduction Occurring in Loss of Load Hours	Share of EUE Reduction Occurring in Non-Loss of Load Hours	Total
Summer	19.68%	0.22%	19.90%	8.73%	0.01%	8.74%
Winter	64.52%	15.58%	80.10%	73.78%	17.48%	91.26%
Total	84.20%	15.80%	100.00%	82.51%	17.49%	100.00%

Table 34 shows that only 84.20% (in 2028/2029) and 82.51% (in 2029/2030) of the accreditation that a class or resource receives depends on modeled performance during the loss of load hours. The remaining, 15.80% and 17.49%, is attributable to modeled performance during non-loss of load hours in days/periods where the system is energy-constrained by enabling the recharge of storage resources or delaying the deployment of storage so that storage resources can provide additional output during the loss of load hours.

A comparison between the values in Table 35 for 2028/2029 and 2029/2030 illustrates how the system in 2029/2030 exhibits a larger share of winter risk as 91.26% of the hours that impact accreditation are from winter (vs. 80.10% in 2028/2029) and as 17.49% of the hours that impact accreditation are from non-loss of load hours (vs. 15.80% in 2028/2029), which tend to occur more in winter as that is the season with more energy-constrained days.

The set of loss of load hours with the associated performance time stamps for the 2028/2029 Delivery Year run can be found in the Info for Loss of Load Hours (XLS) posted file (the corresponding file for 2029/2030 can be found here). Additionally, PJM has identified the set of performance time stamps associated with EUE reduction in Non-Loss of Load Hours. These additional performance time stamps are posted for the 2028/2029 and 2029/2030..

Figure 18 and Figure 19 show a heatmap by season and hour beginning for the hours in the Loss of Load Hour set and the Non-Loss of Load Hour set. In **Figure 19,** most of the hours in the Non-Loss of Load Hour set for 2028/2029 and 2029/2030 are located between the morning and evening peaks in the winter season (i.e., between hour beginning 10 and hour beginning 16).

Figure 18. Heatmap for Loss of Load Hours for 2028/2029 and 2029/2030

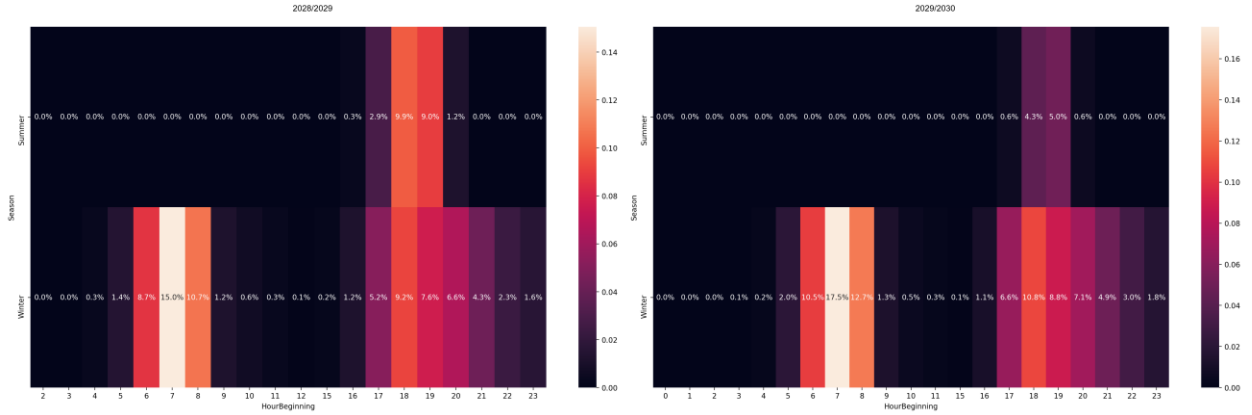


Figure 19. Heatmap for Non-Loss of Load Hours for 2028/2029 and 2029/2030

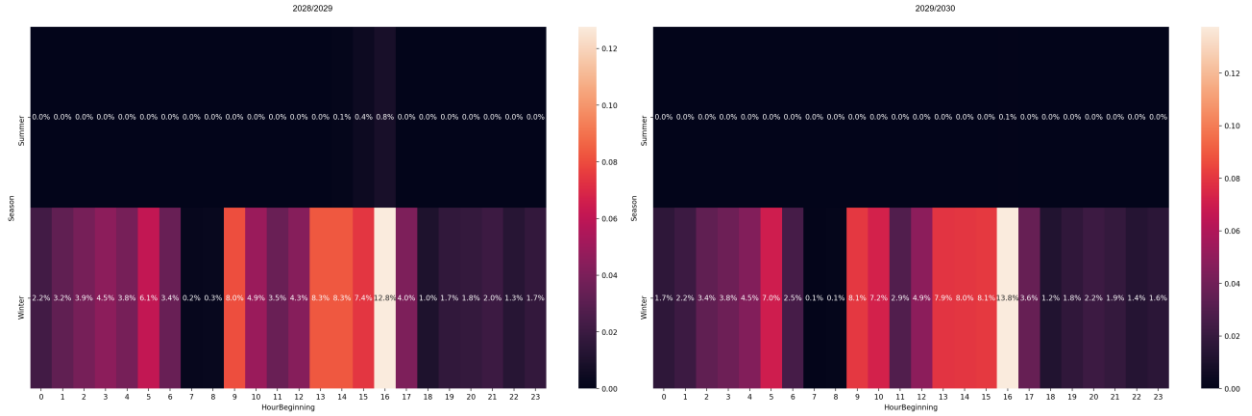


Table 35 summarizes the average performance of ELCC Classes during the Loss of Load Hours and during the hours that show EUE reduction that are not Loss of Load Hours for 2028/2029. Using the 84.20% and 15.80% values as weights for performance during Loss of Load Hours and performance during Non-Loss of Load Hours, respectively, the ELCC Class Ratings can be approximated by performing a weighted average calculation.

Table 35. Average Performance of ELCC Classes During Loss of Load Hours and Non-Loss of Load Hours Identified as Impacting the 2028/2029 Accreditation

ELCC Class	Avg. Performance Loss of Load Hours (as % of ENC/ICAP) Weight = 0.8420	Avg. Performance Non Loss of Load Hours (as % of ENC/ICAP) Weight = 0.1580	Rounded Weighted Average	2028/2029 ELCC Class Rating	Difference: Rounded Wgt Avg – Class Rating
Onshore Wind	32.71%	40.61%	34%	34%	0%
Offshore Wind	56.89%	73.76%	60%	60%	0%
Fixed-Tilt Solar	4.70%	20.58%	7%	7%	0%

ELCC Class	Avg. Performance Loss of Load Hours (as % of ENC/ICAP) Weight = 0.8420	Avg. Performance Non Loss of Load Hours (as % of ENC/ICAP) Weight = 0.1580	Rounded Weighted Average	2028/2029 ELCC Class Rating	Difference: Rounded Wgt Avg – Class Rating
Tracking Solar	7.61%	22.42%	10%	10%	0%
Intermittent Landfill Gas	49.95%	47.98%	50%	50%	0%
Intermittent Hydropower	34.82%	33.51%	35%	35%	0%
Capacity Storage Resource (4-hr)	71.57%	-5.39%	59%	59%	0%
Capacity Storage Resource (6-hr)	79.15%	6.36%	68%	68%	0%
Capacity Storage Resource (8-hr)	79.13%	22.55%	70%	71%	-1%
Capacity Storage Resource (10-hr)	84.19%	44.98%	78%	78%	0%
Demand Resource	97.24%	60.27%	91%	91%	0%
Nuclear	95.80%	95.58%	96%	96%	0%
Coal	84.87%	84.31%	85%	85%	0%
Gas Combined Cycle	78.76%	73.50%	78%	78%	0%
Gas Combustion Turbine	68.56%	58.54%	67%	67%	0%
Gas Combustion Turbine Dual Fuel	79.77%	76.61%	79%	79%	0%
Diesel Utility	92.80%	92.23%	93%	93%	0%
Steam	75.44%	72.16%	75%	75%	0%
Waste to Energy Steam	84.13%	82.36%	84%	84%	0%
Oil-Fired Combustion Turbine	83.48%	80.57%	83%	83%	0%

The weighted average performance values match the 2028/2029 ELCC Class Ratings for all ELCC Classes except one, and in that nonmatching case, the difference is a single percentage point. Note that not all ELCC Class ratings fully match because the above identification of the Non-Loss of Load Hours is performed using the Perfect Capacity run (and each ELCC Class requires its own specific run).

Identifying the set of hours that impact the ELCC Class Ratings as well as the modeled performance for each ELCC Class at such hours provides further insights as to what drives the ratings results. For instance:

- The two solar classes see their ELCC Class Ratings slightly increased by their average performance in the Non-Loss of Load Hours because a large share of such hours is between the morning and evening winter peaks, where solar performance improves relative to the performance during the morning and evening winter peaks (which tend to be where the winter loss of load hours occur).

- The two shorter duration storage classes (4-hr. and 6-hr.) see their ELCC Class Ratings decreased by their average performance in the Non-Loss of Load Hours because storage resources in such hours are recharging (i.e., they are consuming energy from the grid or producing negative output) or producing low output levels. The two longer duration storage classes (8-hr. and 10-hr.) also see their ELCC Class Ratings decrease due to the above but to a lesser degree because in some hours of the Non-Loss of Load Hours set, they produce output to the grid by virtue of their longer duration.

- The DR ELCC Class Rating is decreased by their average performance in the Non-Loss of Load Hours because Demand Resources cannot be dispatched to recharge storage and therefore, in a large share of the Non-Loss of Load Hours (~30%), the modeled DR output is zero.

The calculations shown in **Table 35** can be performed for several of the ELCC Classes using the posted data as follows:

- For Onshore Wind, Offshore Wind, Fixed-Tilt Solar, Tracking Solar, Intermittent Landfill Gas, find the 2028/2029 output of the ELCC class in the applicable column in the file Hourly Time Series Output for Variable Resources Classes (XLS) for each of the time stamps in the Loss of Load Hours file. Then multiply that output by the value in the Weight column in the Loss of Load Hours file. Add up the values resulting from the multiplication. This will yield the Avg. Performance in Loss of Load Hours. For the Avg. Performance in Non-Loss of Load Hours, follow the same procedure instead of using the Non-Loss of Load Hours file.

- For Intermittent Hydropower, follow the same procedure as above, but instead use the Loss of Load Hours Hydro file and the Non-Loss of Load Hours Hydro file, as applicable. Intermittent Hydropower uses different files than other Variable Resources because it is not subject to the temperature binning method.

- For ELCC Classes in the Unlimited Resources category:

  - Find the output of the ELCC class in the applicable column in the file Hourly Time Series Forced Outage for Unlimited Resources Classes (XLS) for each of the time stamps in the Loss of Load Hours file. Then multiply that output by the value in the Weight column in the Loss of Load Hours file. Add up the values resulting from the multiplication. This will yield the Avg. Forced Outage Rate in Loss of Load Hours. For the Avg. Forced Outage Rate in Non-Loss of Load Hours, follow the same procedure instead using the Non-Loss of Load Hours file.

  - Find the output of the ELCC class in the applicable column in the file Hourly Time Series Ambient Derate for Unlimited Resources Classes (XLS) for each of the time stamps in the Loss of Load Hours file. Then multiply that output by the value in the Weight column in the Loss of Load Hours file. Add up the values resulting from the multiplication. This will yield the Avg. Ambient Derate in Loss of Load Hours. For the Avg. Ambient Derate in Non-Loss of Load Hours, follow the same procedure instead using the Non-Loss of Load Hours file.

- To allocate the average amount of planned and maintenance outages (POMO) scheduled during Loss of Load Hours (1,712.74 MW) and the average amount of planned and maintenance outages scheduled during Non-Loss of Load Hours (2,168.88 MW), use the Share of Scheduled Maintenance and Planned Outages by Unlimited ELCC (XLS) file. For instance, for Coal, the share in the file is 0.329662. In the case of the POMO scheduled during Loss of Load Hours, Coal will get 0.329662 x 1,712.74 = 564.625 MW of allocation. To convert this value to a rate, divide the POMO megawatt value by the total ICAP of the ELCC Class in the Resource Portfolio. In the case of Coal and POMO scheduled during Loss of Load Hours, 564.625 / 31,904 MW = 0.017698. This value is the Avg. POMO Rate in Loss of Load Hours. The same procedure can be used to derive the Avg. POMO Rate in Non-Loss of Load Hours but using 2,168.88 MW instead of 1,712.74 MW.
- To derive the Avg. Performance in Loss of Load Hours in **Table 35**:
  - Avg. Performance in Loss of Load Hours = 1 - Avg. Forced Outage Rate in Loss of Load Hours - Avg. Ambient Derate in Loss of Load Hours - Avg. POMO Rate in Loss of Load Hours.

  To derive the Avg. Performance in Non-Loss of Load Hours, follow the same formula as above but using the values calculated for the Non-Loss of Load Hours.

- For Demand Resources: find the output of the DR class in 2028/2029 in the file Info for Loss of Load Hours for each of the time stamps in the loss of load hours. Then multiply that output by the value in the Weight column in the Loss of Load Hours file. Add up the values resulting from the multiplication. This will yield the Avg. Performance in Loss of Load Hours. For the Avg. Performance in Non-Loss of Load Hours, follow the same procedure instead of using the Simulated DR Performance in Additional Critical Performance Hours. In this same file, the Calculations tab illustrates how to use the simulated performance during the non-loss of load hours and the simulated performance during loss of load hours to come up with the weighted average performance during all critical hours.
- For Limited Duration Resources: the calculation is identical to the calculation for Demand Responses. However, due to confidentiality reasons, the output of each Limited Duration ELCC Class cannot be posted publicly.

Table 36 summarizes the average performance of ELCC Classes during the Loss of Load Hours and during the hours that show EUE reduction that are not Loss of Load Hours for 2029/2030. Using the 82.51% and 17.49% values as weights for performance during Loss of Load Hours and performance during Non-Loss of Load Hours, respectively, the ELCC Class Ratings can be approximated by performing a weighted average calculation. The commentary for **Table 35** also applies to **Table 36** below (note, however, that the data that applies to this table is posted in PJM's ELCC website under 2029/2030)

Table 36. Average Performance of ELCC Classes During Loss of Load Hours and Non-Loss of Load Hours Identified as Impacting the 2029/2030 Accreditation

ELCC Class	Avg. Performance Loss of Load Hours (as % of ENC/ICAP) Weight = 0.8251	Avg. Performance Non Loss of Load Hours (as % of ENC/ICAP) Weight = 0.1749	Rounded Weighted Average	2029/2030 ELCC Class Rating	Difference: Rounded Wgt Avg – Class Rating
Onshore Wind	36.03%	41.24%	37%	37%	0%
Offshore Wind	61.93%	74.59%	64%	65%	-1%
Fixed-Tilt Solar	2.82%	21.70%	6%	6%	0%
Tracking Solar	3.99%	23.61%	7%	7%	0%
Intermittent Landfill Gas	49.75%	48.62%	50%	50%	0%
Intermittent Hydropower	34.29%	33.55%	34%	34%	0%
Capacity Storage Resource (4-hr)	69.49%	-4.32%	57%	57%	0%
Capacity Storage Resource (6-hr)	79.88%	5.38%	67%	66%	+1%
Capacity Storage Resource (8-hr)	78.91%	22.66%	69%	69%	0%
Capacity Storage Resource (10-hr)	82.70%	46.41%	76%	76%	0%
Demand Resource	95.29%	64.25%	90%	90%	0%
Nuclear	95.64%	95.53%	96%	96%	0%
Coal	84.21%	83.81%	84%	84%	0%
Gas Combined Cycle	75.01%	71.40%	74%	75%	-1%
Gas Combustion Turbine	60.15%	54.46%	59%	59%	0%
Gas Combustion Turbine Dual Fuel	75.87%	74.58%	76%	76%	0%
Diesel Utility	91.96%	91.92%	92%	92%	0%
Steam	75.28%	73.97%	75%	75%	0%
Waste to Energy Steam	82.71%	82.32%	83%	83%	0%
Oil-Fired Combustion Turbine	81.09%	79.45%	81%	81%	0%

Delivery Years 2030/2031 Through 2042/2043

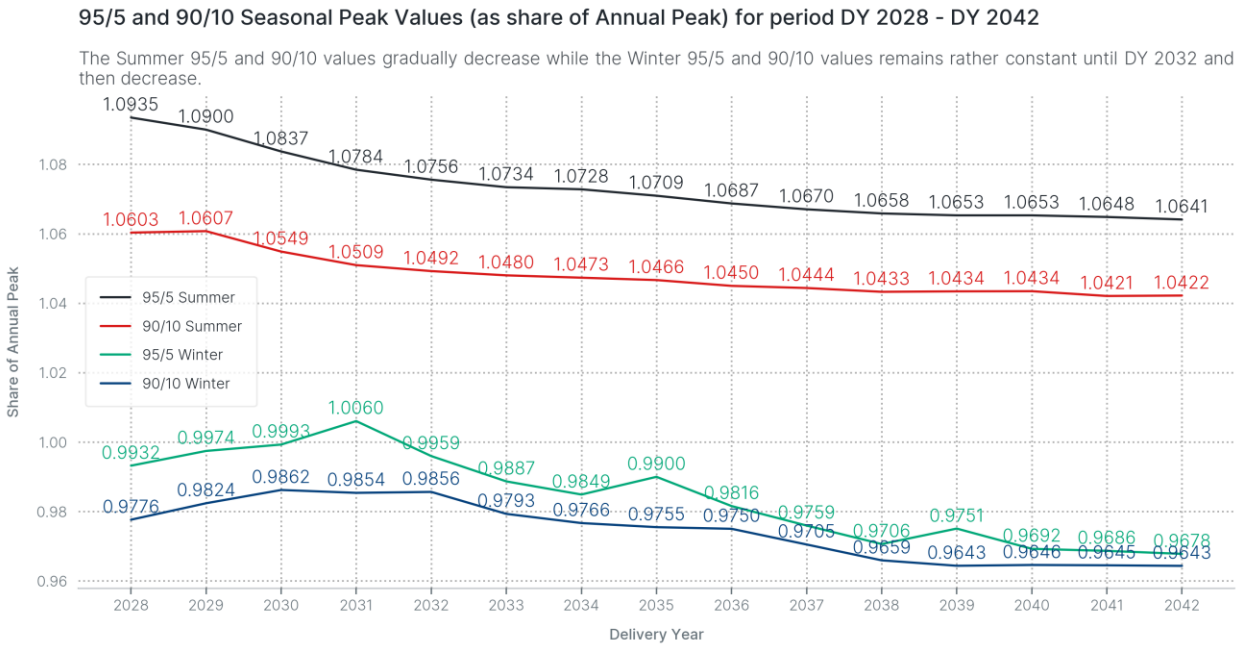
PJM also performed analysis for Delivery Years in the period 2030/2031 through 2042/2043. In a regular version of the ELCC/RRS, the analysis would have covered only until DY 2036/2037. However, because of requirements under PJM's proposed Reliability Backstop Procurement, this year the analysis was performed until DY 2042/2043. Note that the sections below include the results for DYs 2028/2029 and 2029/2030 that have already been discussed throughout this report.

Inputs

Most of the inputs included in the runs for delivery years in the period 2030/2031 through 2042/2043 are identical to those used in the 2029/30 BRA run. These include the temperature bins, the hourly time series of ambient derates for Unlimited Resources, the hourly time series of forced outages for Unlimited Resources, the hourly time series of output for Variables Resources. However, there are two inputs that are specific to each of the delivery years in the period 2030/2031 through 2042/2043.

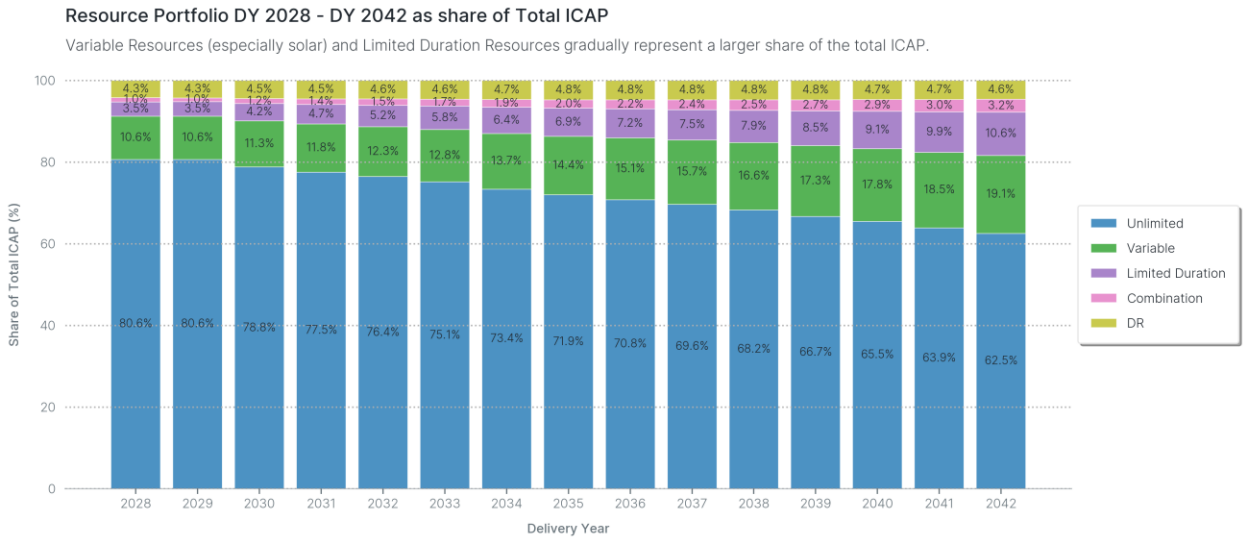
1) **Load Scenarios:** the load scenarios for each of the delivery years were derived from the 2026 PJM Load Forecast. **Figure 20** shows the 90/10 and 95/5 seasonal peak values for the DY in the period as a share of the respective 50/50 annual peaks. For the winter values, there is an increasing trend until DY 2032 and then a gradual decrease until DY 2042; for the summer values, there is a decreasing trend during the entire 15-year period. Consequently, the load scenarios put upward pressure on winter risk until DY 2032 and downward pressure thereafter. Analysis of monthly extreme loads as a share of the respective 50/50 annual peaks (not shown in graph below) shows that October, November and April are the only months with an increasing trend during the entire 15-year period.

Figure 20. 95/5 and 90/10 Seasonal Peak Values



2) **Resource Portfolios Scenarios:** The resource portfolio for each Delivery Year was developed by starting with the resource portfolio used in the 2029/30 BRA and then using a forecast of resource additions and retirements produced by a vendor. **Figure 21** shows that the ICAP share of Unlimited Resources decreases throughout the 10-yr period while the ICAP share of Variable Resources and Limited Duration Resources increases. The gradual change in resource portfolio throughout the study period puts upward pressure on winter risk for the PJM system as Unlimited Resources retire and are replaced by solar and short-duration storage resources, where such assets provide relatively lower performance during the extended periods of winter risk compared to shorter-duration summer risk periods.

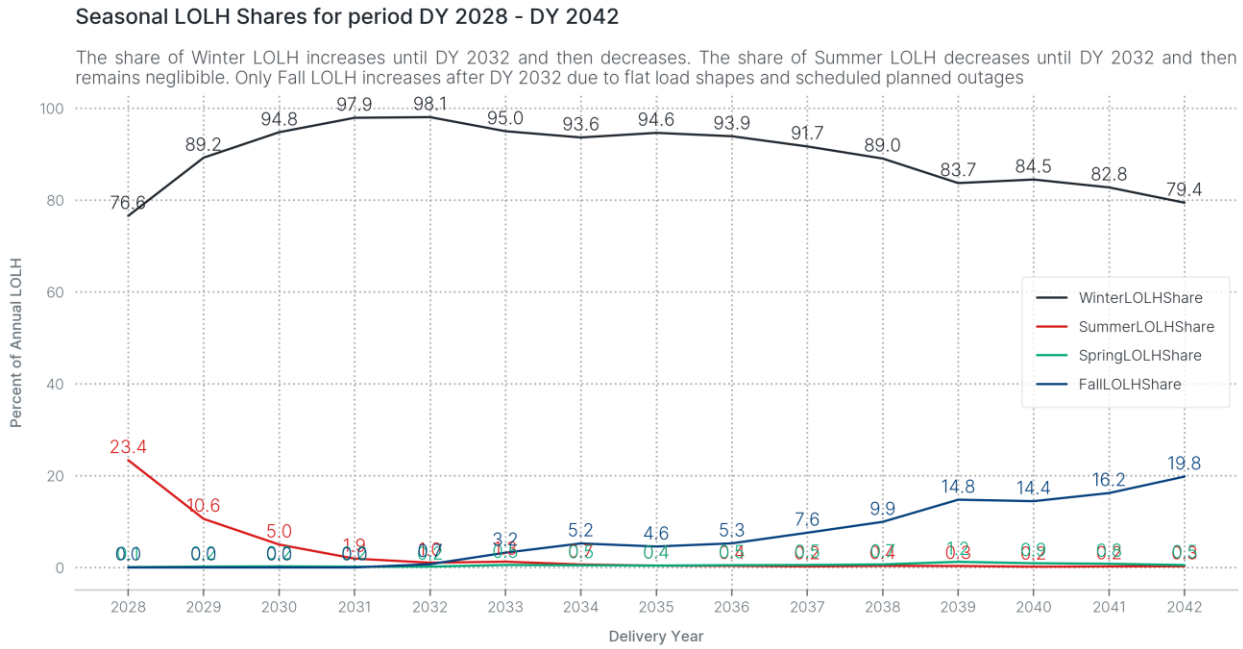
Figure 21. Resource Portfolio DY 2028 to DY 2042



Outputs

The seasonal Loss of Load Hour (LOLH) shares for each DY in the period are shown in **Figure 22**. For this graph, the seasons were defined as including three months each. The share of winter LOLH increases in a manner consistent with the increases in extreme winter loads until DY 2032 and then gradually decreases. The share of summer LOLH decreases until DY 2032 and then remains negligible. The share of fall LOLH is negligible until DY 2032 and then gradually increases. The fall risk is driven by a combination of factors: planned and maintenance outages, resource portfolios with more Variable and Limited Duration Resources, forced outage patterns of Unlimited Resources that are higher than average for the season and an increasing trend in extreme loads in the month of October.

Figure 22. Seasonal LOLH Shares for Period DY 2028 to DY 2042



In addition to the trend of increasing winter and fall risk observed for the study period, there is another trend that has an impact on the ELCC Class Ratings. The ELCC Class Ratings are calculated based on the Expected Unserved Energy (EUE) reduction that a marginal addition of each class produces compared to the EUE reduction produced by a marginal addition of perfect capacity. An analysis of the EUE reduction produced by the marginal addition of perfect capacity shows that the EUE reduction is caused by: i) perfect capacity output during loss of load hours and ii) perfect capacity output during certain non-loss of load hours.

The EUE reduction due to perfect capacity output during loss of load hours is straightforward: if there was a loss of load hour in the base 1 in 10 case and the amount of unserved energy in the hour was, say, 1,000 MW, then after adding 100 MW of perfect capacity in that hour, the new unserved energy in the hour will be 900 MW.

The EUE reduction due to output during certain non-loss of load hours, on the other hand, is less straightforward because the EUE reduction is generated by perfect capacity output during non-loss of load hours that enables other resources, specifically storage (via charging or by delaying the storage deployment), to produce more output during loss of load hours. For example, when the model is simulating a multi-day polar vortex event, and storage is depleted by the end of the first day, if the load remains high overnight, storage will not be able to recharge and will face the second day of the event depleted. After adding a marginal amount of perfect capacity during, say, 2am-5am, the perfect capacity MWs will enable the charging of storage resources (or the delay in the deployment of storage), and now the storage resources will be able to produce non-zero MWs during the second day of the polar vortex event, reducing the system EUE in a hour by more than 100 MW (i.e, the perfect capacity modeled in the hour plus an adder generated by the output of the enabled storage resources).

Figure 23 shows the share of the EUE reduction due to the addition of perfect capacity that is caused by output during loss of load hours. It can be observed that it starts very high at the beginning of the period (at more than 80%) while it gets reduced drastically as the system faces more winter risk and more energy-constrained days.

Figure 23. Share of Accreditation Depending on Performance During LOLH

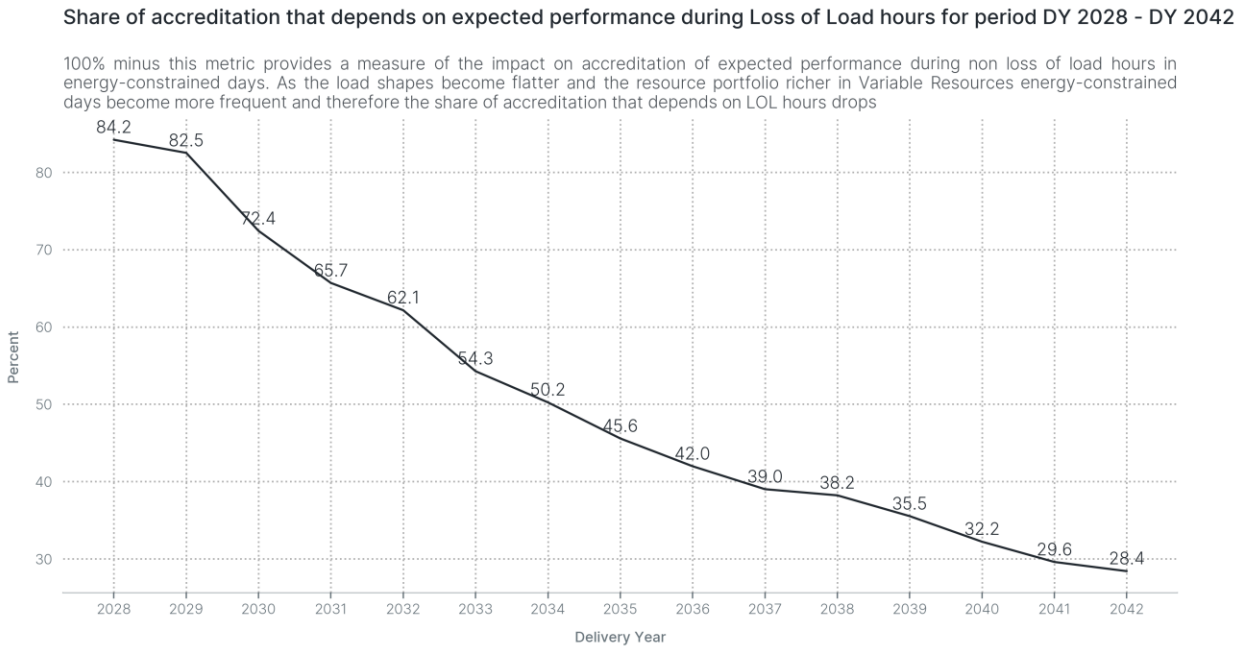
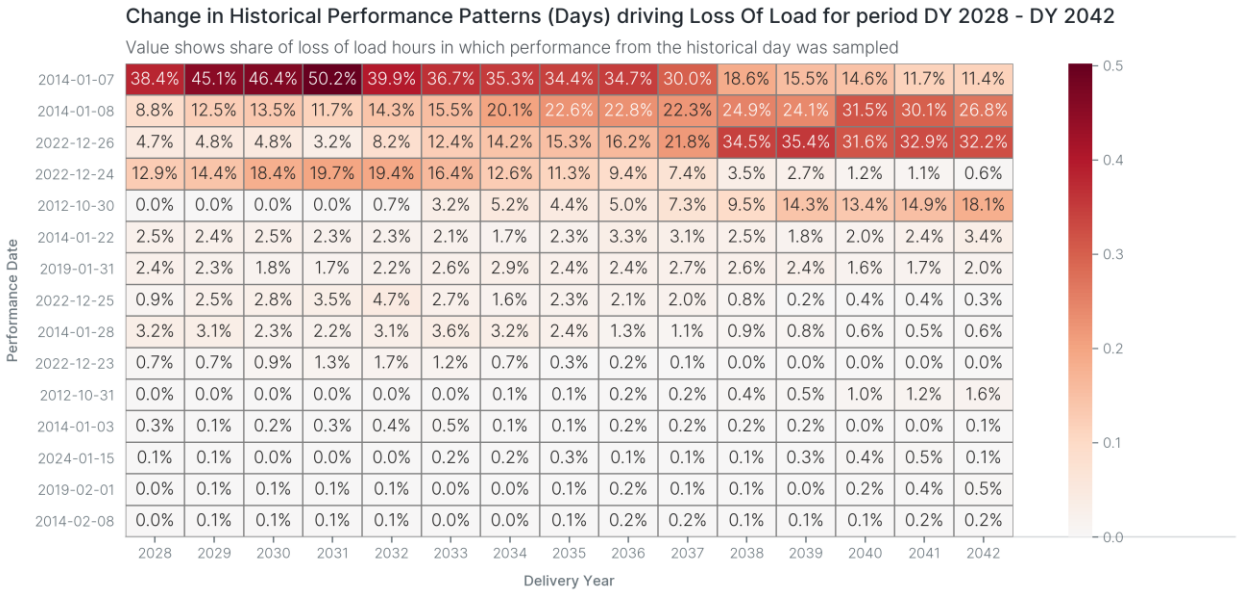


Figure 23 is relevant to understand the decrease in ELCC Class Ratings for ELCC Classes that are not modeled as able to charge storage (Demand Response and other Limited Duration Resources). In other words, the importance of enabling the charging of storage for accreditation purposes consistently increases as the system faces more winter risk and more energy-constrained events. This is an important point because, as noted in the resource portfolio discussion, Limited Duration resources (i.e., storage) gradually make up a larger share of the resource portfolio.

Another model output that is key to understanding the changes in some of the ELCC Class Ratings is the historical resource performance patterns that drive the system risk in each DY of the study period, shown in **Figure 24**.

Figure 24. Changes in Historical Performance Patterns Driving Loss of Load



As the resource portfolio changes in the study period, the performance patterns that drive risk in the model also change. For example, this occurs because classes that performed well (i.e. onshore wind) on 2014-01-07 did not perform as well on, say, 2014-01-08 (see Performance On Select Historical Dates for more background). As the wind share of ICAP increases in the resource portfolio, the historical performance pattern of 2014-01-07 will drive less risk in the model while the historical performance pattern of 2014-01-08 will drive more risk in the model. In other words, as onshore wind makes up a larger share of the resource portfolio in the future, the types of events in which winter risk is observed in the system tend to shift towards those days that see high correlated unavailability of the wind fleet.

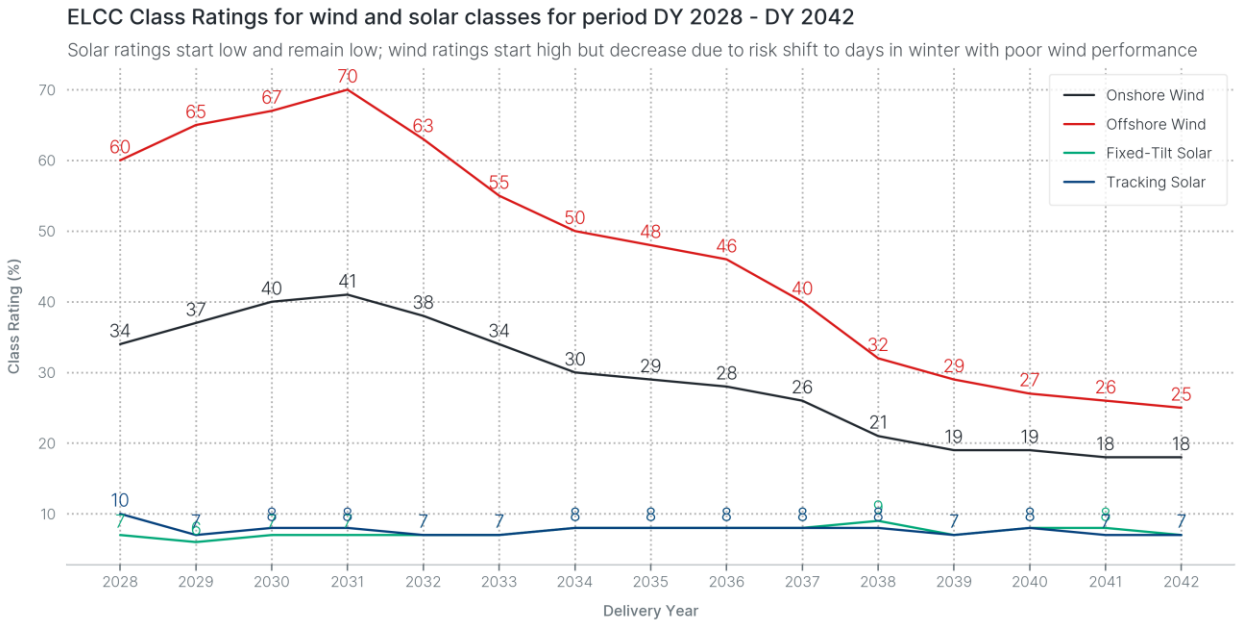
ELCC Class Ratings

Variable Resource Class Ratings

As shown in **Figure 25** the ratings for the two solar classes remain stable at low values during the entire period due to the high level of winter risk. Solar Fixed ratings are slightly higher than Solar Tracking ratings in two years later in the study period due to better performance of Solar Fixed resources on 2022-12-26 which becomes more relevant in the later years as shown in **Figure 24**.

The ratings for the two wind classes decrease significantly due to a gradual shift in winter historical performance patterns driving the winter risk in the model (as shown in the above heatmaps).

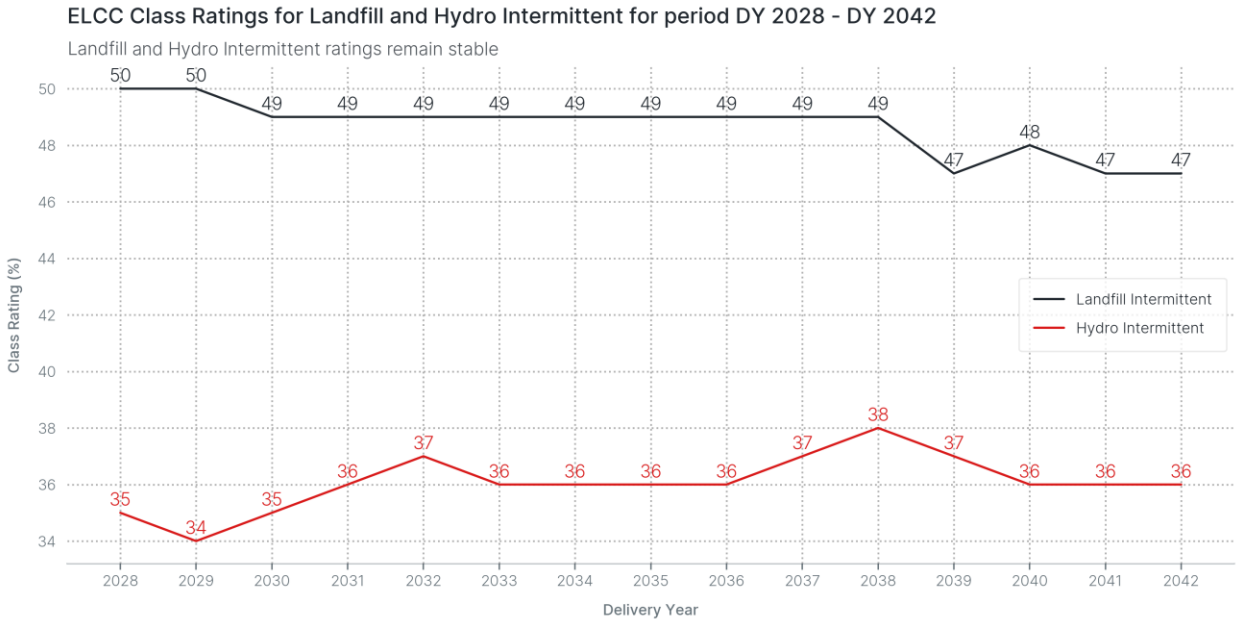
Figure 25. ELCC Class Ratings for Wind and Solar



Landfill Intermittent and Hydro Intermittent Class Ratings

As shown in **Figure 26**, the ratings for these two classes remain rather stable in the study period due to their output not being as volatile as that of other classes

Figure 26. ELCC Class Ratings for Landfill and Hydro Intermittent



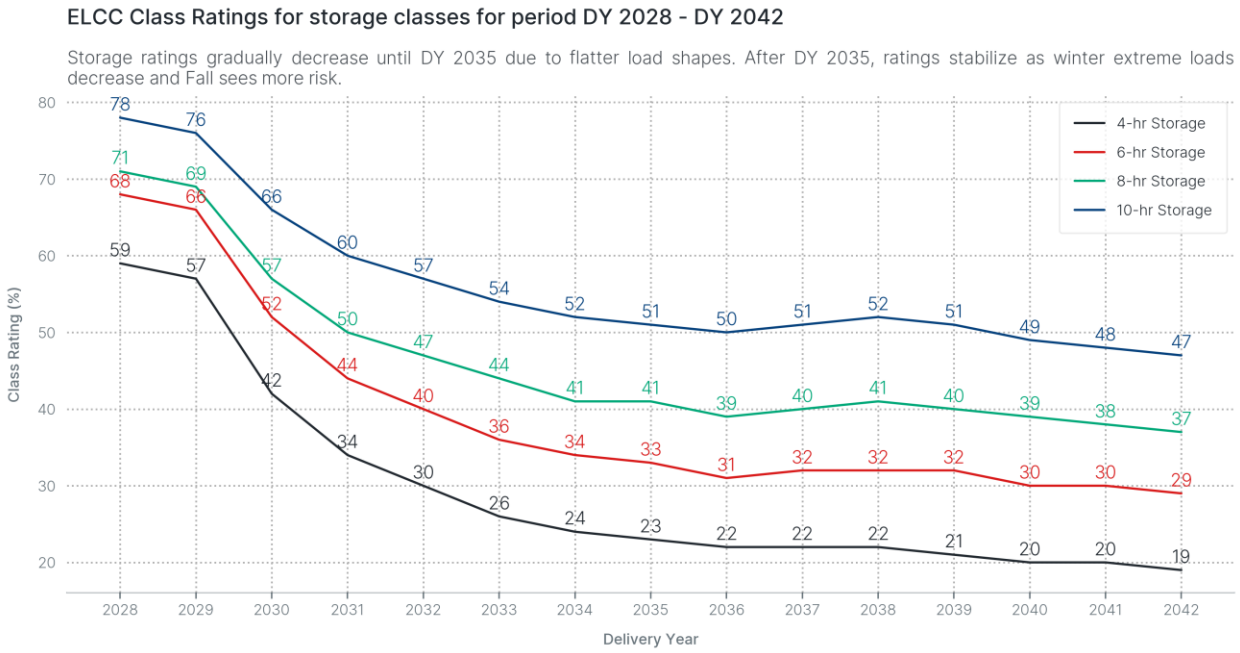
Storage Class Ratings

As shown in **Figure 27**, the ratings for the storage classes drop consistently throughout the study period due to increasing winter risk. Winter risk periods tend to last multiple hours due to flat load shapes and the protracted

duration of Unlimited Resources' forced outages under cold weather, which is not conducive to sustained good performance by storage resources for the entire duration of the risk events. This is the main driver for the drop in ratings.

In addition, storage resources cannot charge other storage resources during winter energy-constrained events in the model and, as shown in **Figure 23**, the ability to charge storage towards the end of the study period becomes more important for accreditation purposes.

Figure 27. ELCC Class Ratings for Storage Classes



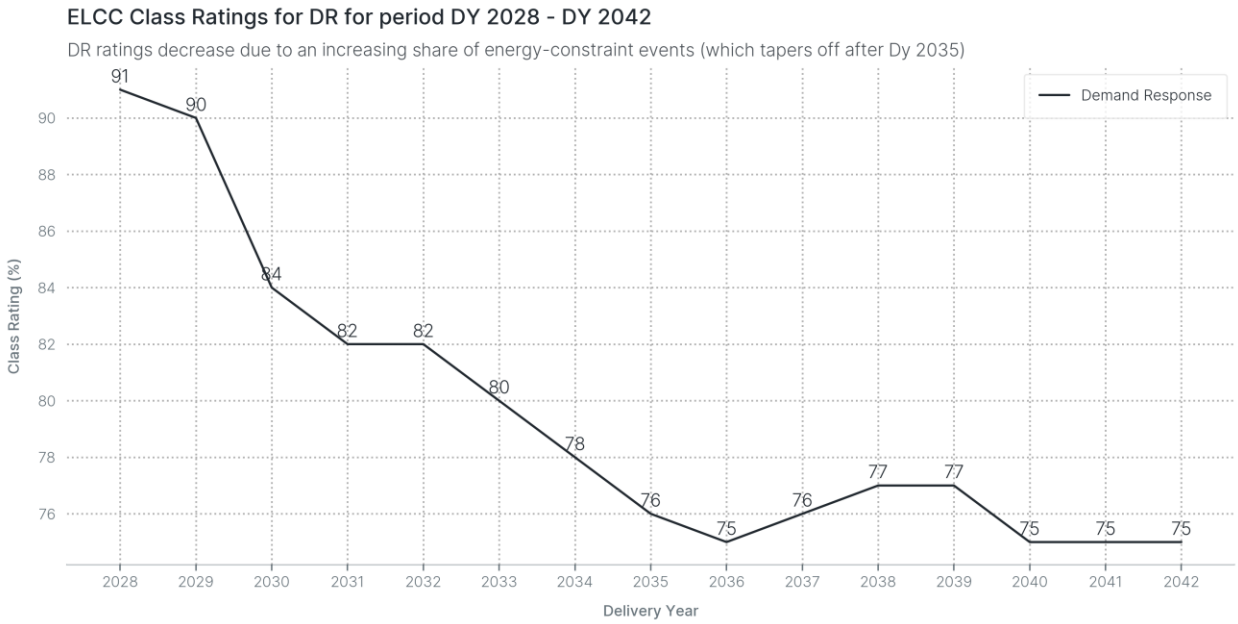
Demand Response Class Ratings

The rating for the demand response (DR) class drops consistently until DY 2036 due to increasing winter risk. The reduction capability of DR in the winter period is assumed to be less than during the summer period[7]. As falls risk starts increasing (after DY 2036), the DR ratings stop decreasing.

Similar to the storage case described above, DR resources are not assumed to be deployed to charge storage resources and, as shown in **Figure 23**, the ability to charge storage towards the end of the study period becomes more important for accreditation purposes.

[7] See Demand Response discussion in pages 25-27 in the 2025 ELCC/RRS Report available at https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2025-pjm-elcc-rrs.pdf

Figure 28. ELCC Class Ratings for DR

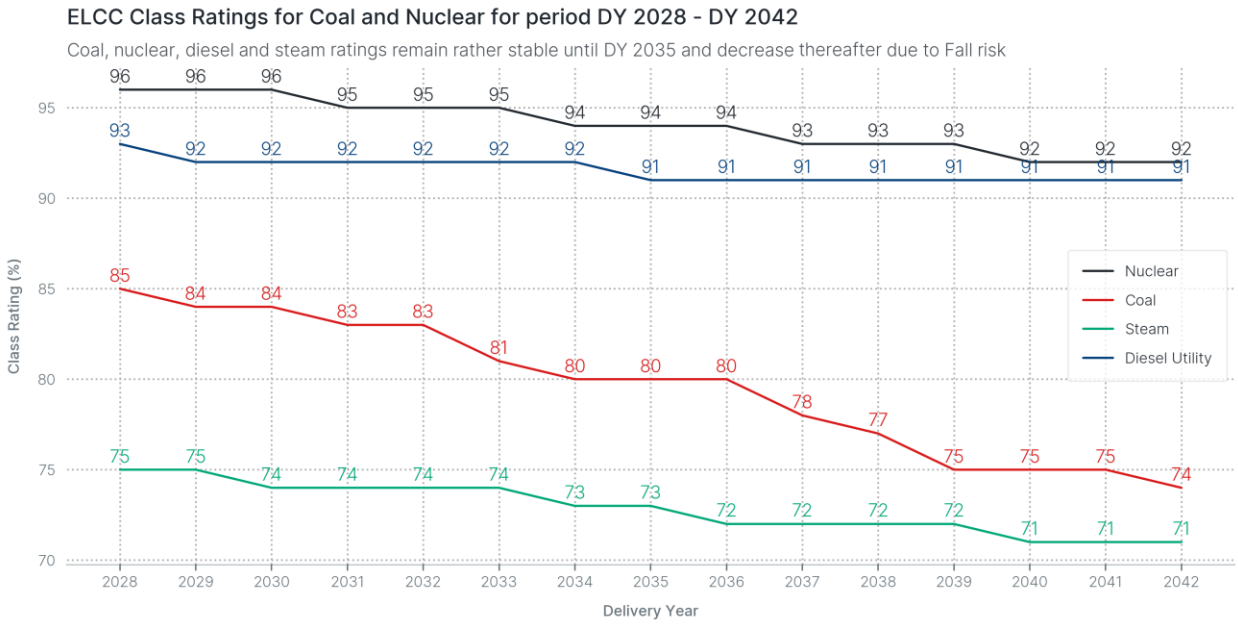


Nuclear, Coal, Steam and Diesel Utility Class Ratings

As shown in **Figure 29**, the ratings for the Nuclear, Steam and Diesel Utility classes remain relatively stable until DY 2036 and decrease thereafter due to fall risk driven by planned and maintenance outages.

The rating for the Coal class consistently decreases as winter risk increases (at the beginning of the study period) and fall risk increases. The fall risk impacts the coal class significantly as coal resources have larger planned and maintenance outage needs.

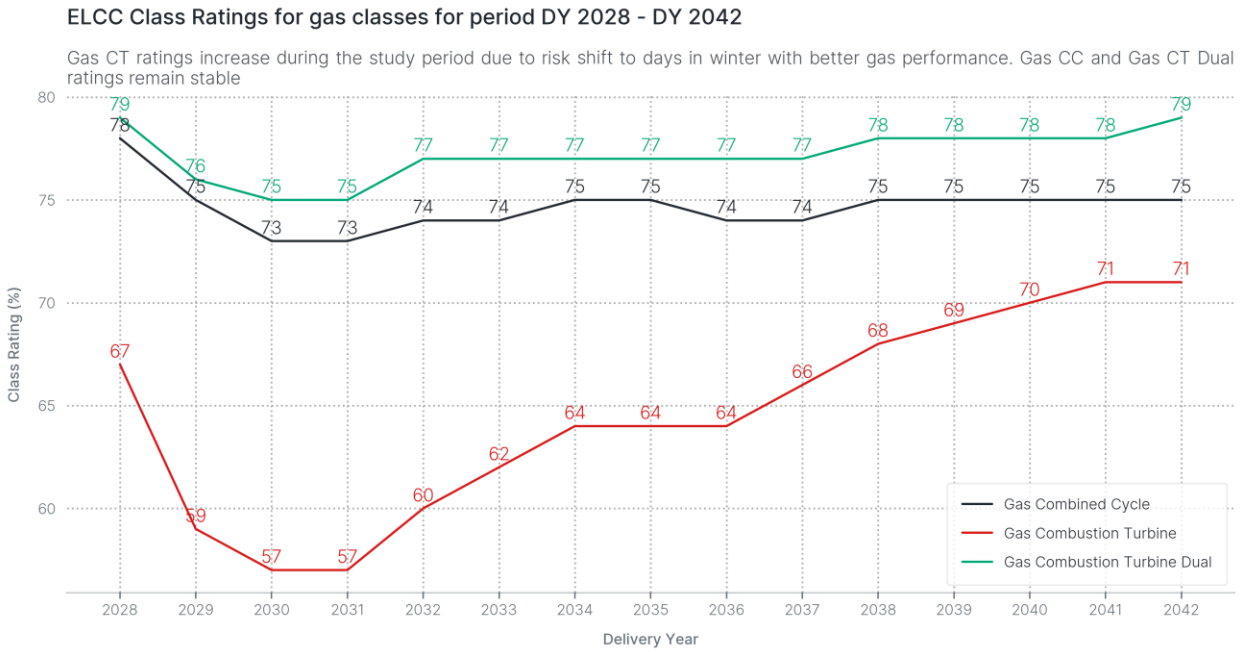
Figure 29. ELCC Class Ratings for Nuclear, Coal, Steam, and Diesel Utility Classes



Gas Class Ratings

The ratings for the gas classes see an initial decrease at the beginning of the study period due to increasing winter risk (and class membership in the specific case of the Gas Combustion Turbine in the change from DY 2028 to DY 2029), followed by an increase for Gas Combined Cycle and Gas Combustion Turbine Dual and a larger increase for Gas Combustion Turbine due to a gradual shift in winter historical performance patterns driving the winter risk in the model. The performance patterns that drive the risk towards the end of the study period show slightly better gas performance than the performance patterns that drive the risk at the beginning of the study period (see Performance On Select Historical Dates for more background).

Figure 30. ELCC Class Ratings for Gas Classes

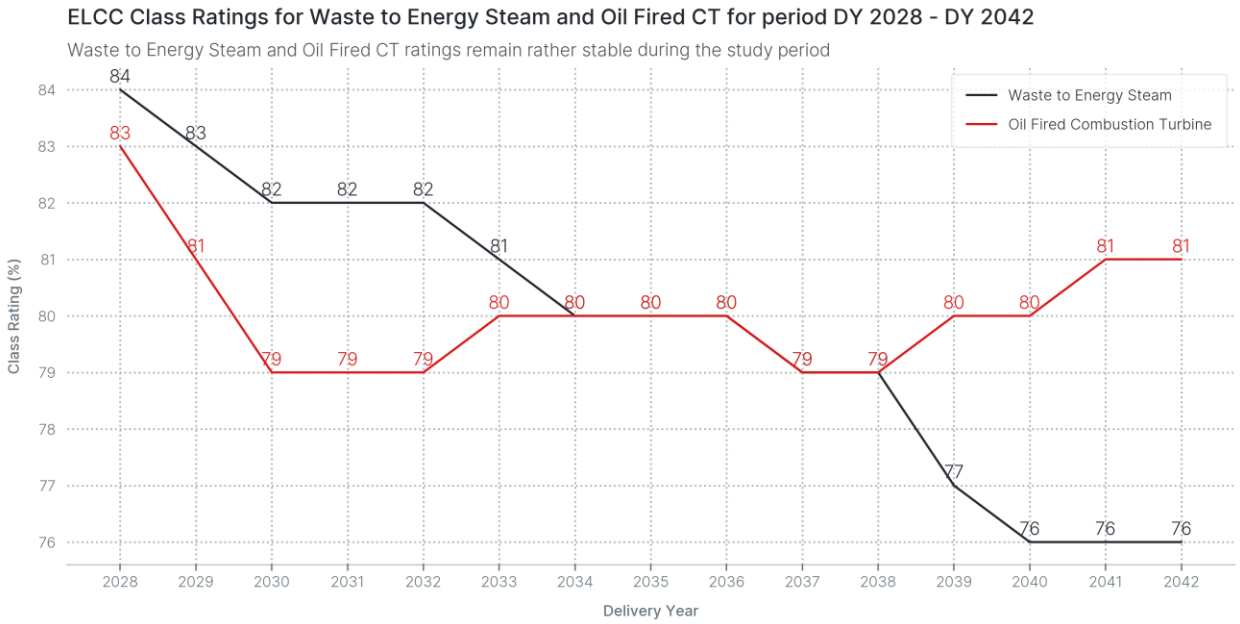


Oil-Fired CT and Waste to Energy Steam Ratings

The ratings for the Oil-Fired Combustion Turbine Class tend to decrease due to the increasing fall risk (as discussed for other Unlimited Resources classes) but the drop is to a certain degree offset by the gradual shift in winter historical performance patterns driving the winter risk in the model.

The ratings for the Waste to Energy Steam class consistently decrease as the fall risk increases and winter historical performance patterns driving the winter risk in the model shift (both negatively impact the class rating given the lower historical performance observed in those periods)

Figure 31. ELCC Class Ratings for Oil-Fired CT and Waste to Energy Steam



Performance on Select Historical Dates

Note: the graphs below show *Availability Rate* for Onshore Wind and the solar classes and *Forced Outage Rate* for unlimited resources classes.

Figure 32. Availability Rate on Select Dates for Onshore Wind

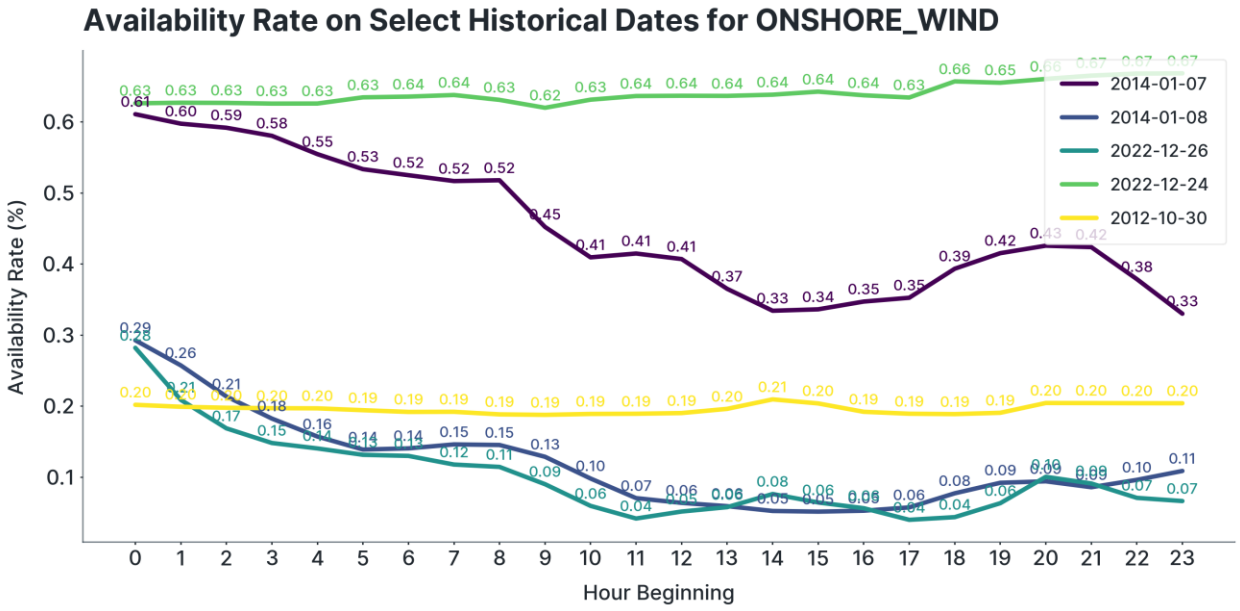


Figure 33. Availability Rate on Select Dates for Fixed Solar

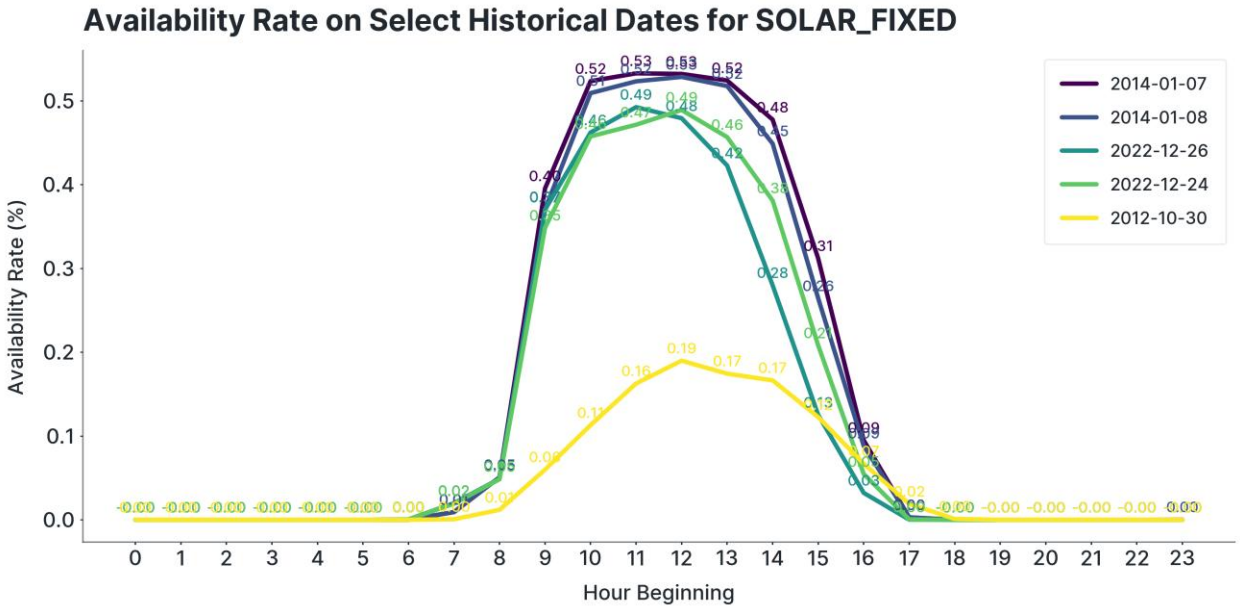


Figure 34. Availability Rate on Select Dates for Tracking Solar

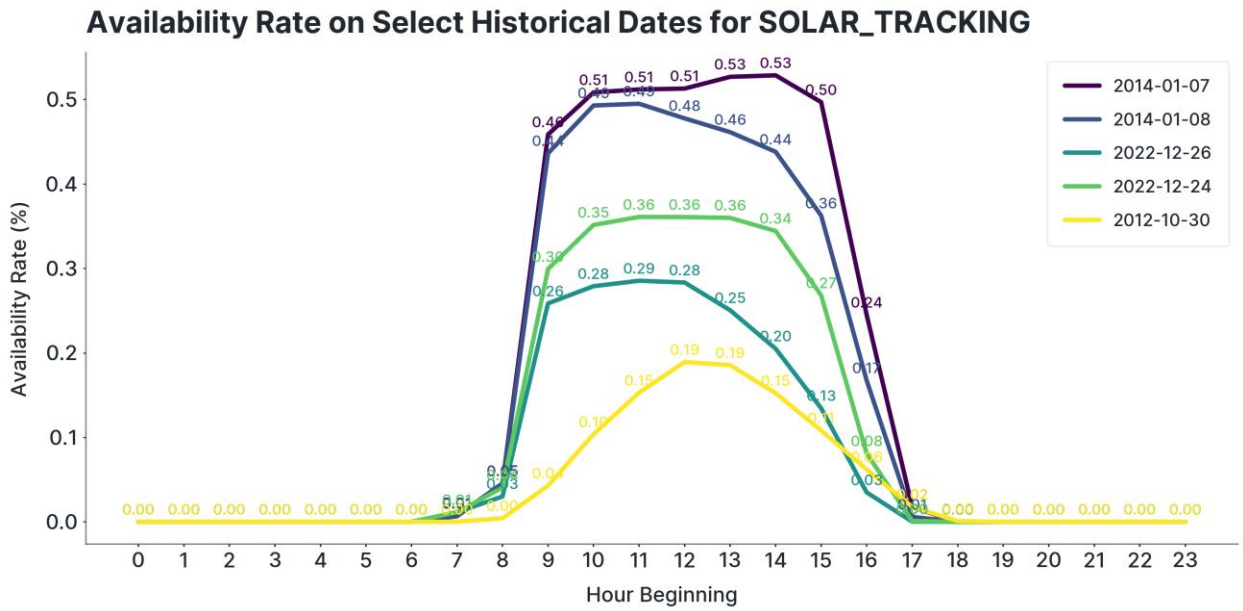


Figure 35. Forced Outage Rate on Select Dates for Gas Combined Cycle

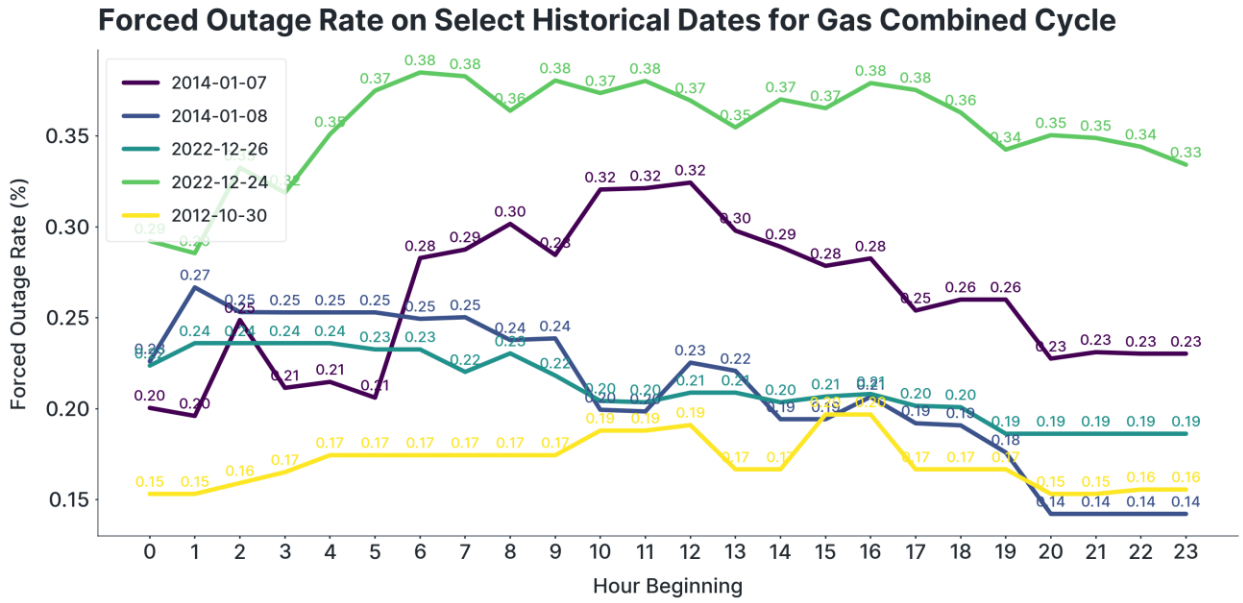


Figure 36. Forced Outage Rate on Select Dates for Gas Combustion Turbine

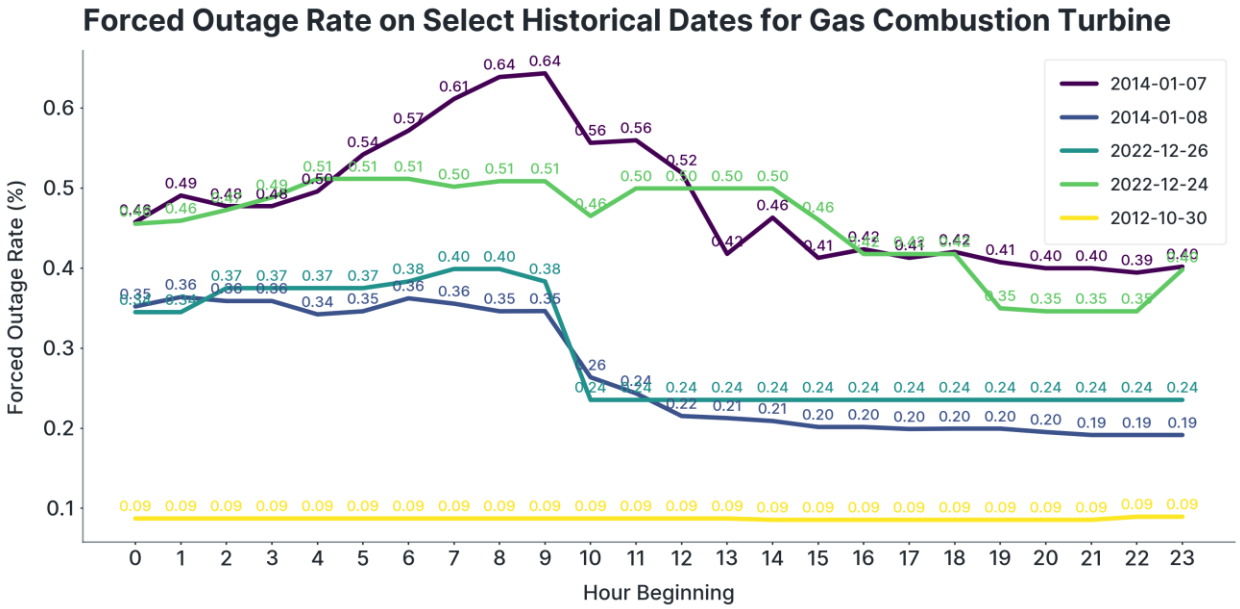


Figure 37. Forced Outage Rate on Select Dates for Gas Combustion Turbine Dual

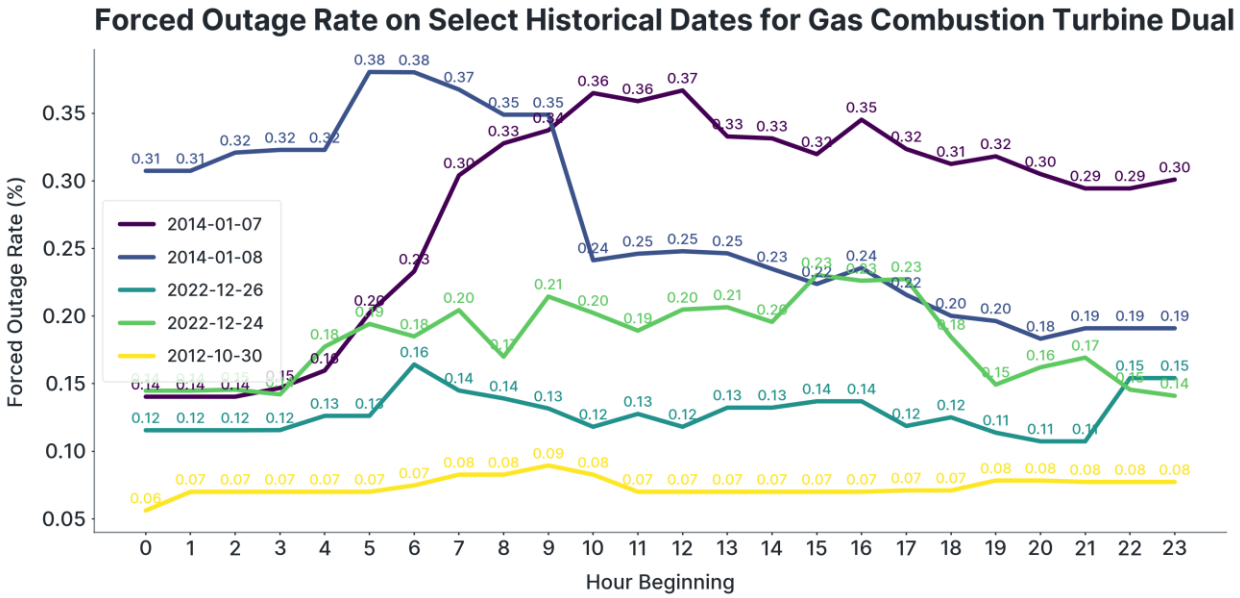


Figure 38. Forced Outage Rate on Select Dates for Coal

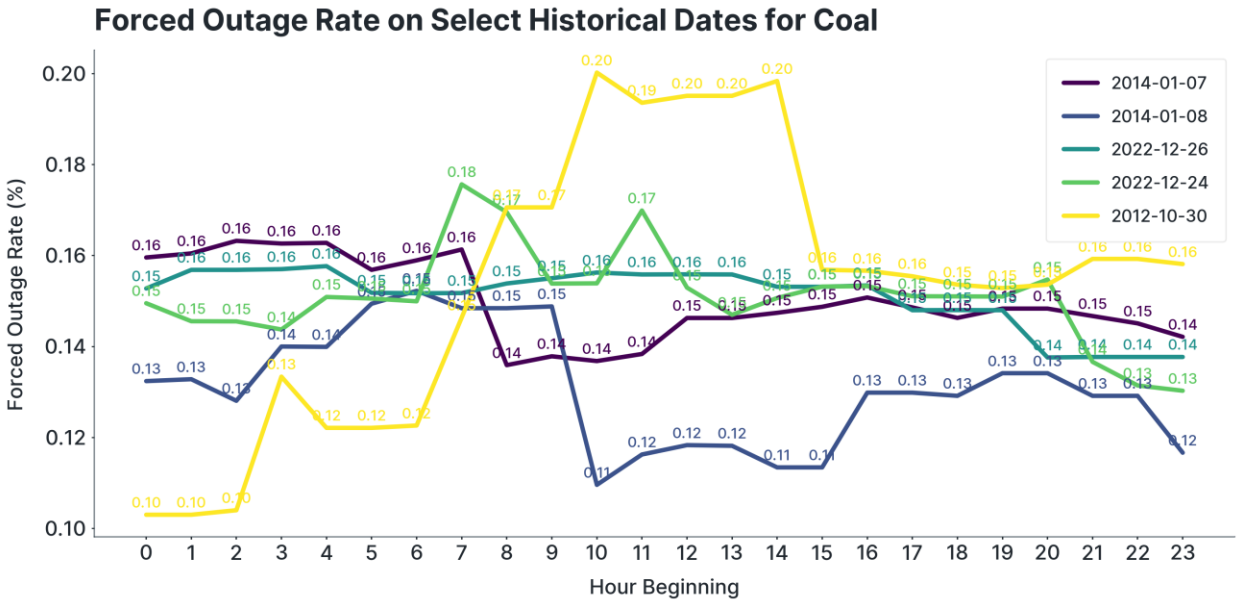


Figure 39. Forced Outage Rate on Select Dates for Nuclear

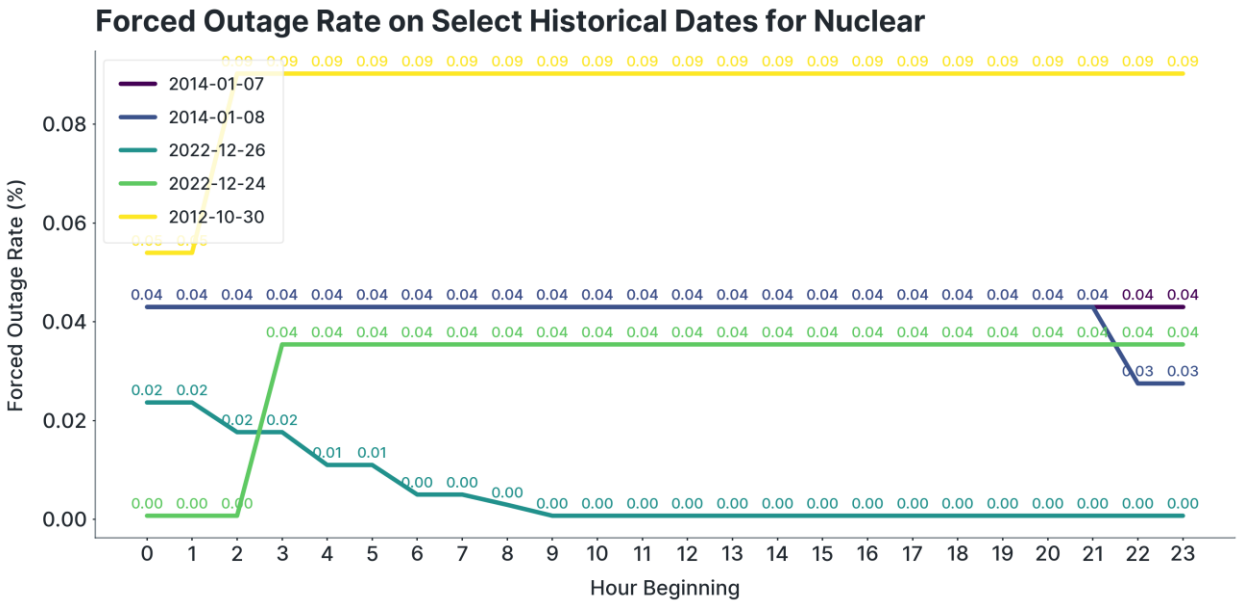
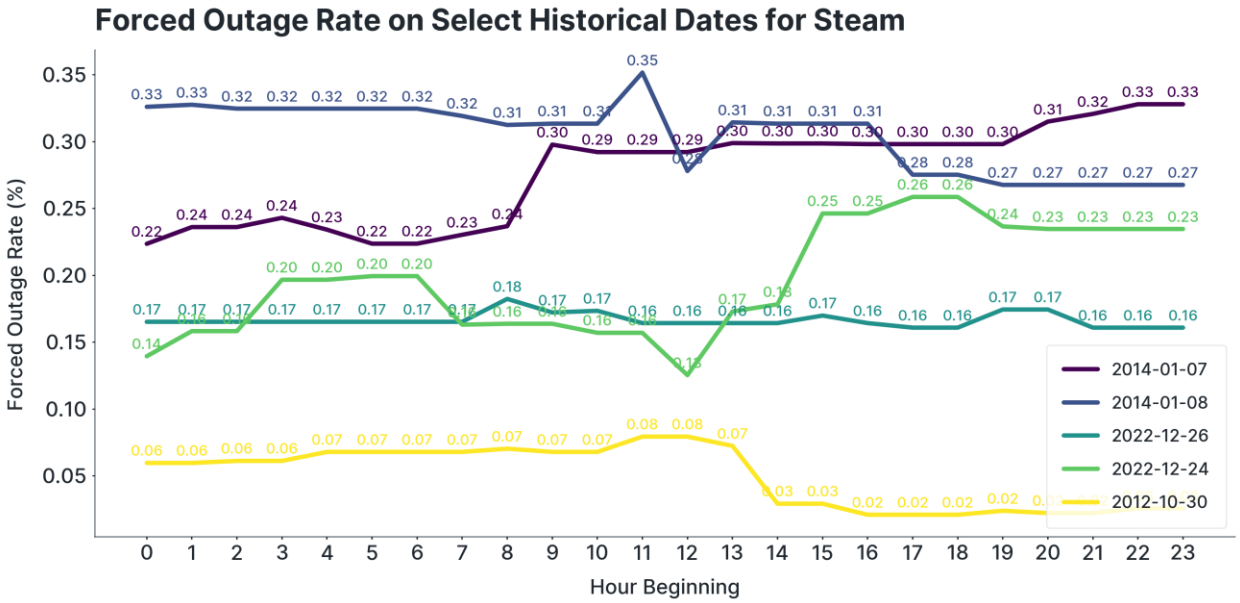


Figure 40. Forced Outage Rate on Select Dates for Steam



Appendix I: Pseudo-code

Algorithm: LOLE & EUE calculation

Inputs: Load scenarios $Load_{s,h}$, Resource Availability ($A_{s,h,r}$) scenarios, EFORd, THI Bins, …

Outputs: LOLE & EUE

for s in 403 Scenarios:

    for h in 8760 Hours:

        for r in 100 performance cases:

            $SDM_{s,h,r} = -Load_{s,h}$ #Loads were unitized so that LOLE=0.1

            for i in resource assets

                switch i:

                case Unlimited: $SDM_{s,h,r,i} \mathrel{+}= ICAP_i - Out_{s,h,r,i}^{unplanned}$

                case Solar/Wind, Landfill: $SDM_{s,h,r,i} \mathrel{+}= \min(A_{s,h,r,i}, Cap_{h,i})$ #A=(ENC or ICAP)*AvailRate

                case Hydro: $SDM_{s,h,r,i} \mathrel{+}= \min(A_{Y^*,h,i}, Cap_{h,i})$ # Y^* is determined by s

            $SDM_{s,h,r} \mathrel{-}= Out_{s,h}^{Planned}$

            for i in Hydro non-pump # hydro non-pump recharge/discharge is independent from SDM

                $SDM_{s,h,r} \mathrel{+}= \sum_i \{MinOutput_{h,i}\}$ # add the minimum output of hydro

                if $S_{s,h,r,i} < SCap_i$: # recharge when it's not full

                    $\Delta S_{s,h,r,i} = \min(Wd_i, SCap_i - S_{s,h-1,r,i}), SDM_{s,h,r} \mathrel{-}= \Delta S_{s,h,r,i}, S_{s,h,r,i} \mathrel{+}= \Delta S_{s,h,r,i}.$

                else: #Storage is full, excess output added to grid

17 $SDM_{s,h,r} \mathrel{+}= XOutput_{Y^*,h,i}$ *#Excess output is determined by the stream flow in year* Y^*

18 $SDM_{s,h,r} \mathrel{+}= \sum_i A_{s,h,r,i}$ # add **variable resource component** in open loop combination resources

19 ***for i*** in VarRsrc Open Loop: $S^{hybrid}_{s,h,r,i} = A_{s,h,r,i}$ # same variable resource as above

20

21 ***if*** $SDM_{s,h,r} > 0$
#Recharge/Injection

22 ***for i*** in Closed-Loop Combo # recharged by attached Variable Resources

23 $\Delta S_{s,h,r,i} = \min(SCap_i - S_{s,h-1,r,i}, ICap_{inj}, A^{VarRsc}_{s,h,r,i})$, # determine recharge need of Lim-Dur Cmpnt

24 $S_{s,h,r,i} = S_{s,h-1,r,i} + \Delta S_{s,h,r,i}, A^{VarRsc}_{s,h,r,i} \mathrel{-}= \Delta S_{s,h,r,i}$, # update availability in Var. Cmpnt

25

26 $\Delta S_{s,h,r} = 0$

27 ***for i*** in Lim-Dur. Cmpnt of Open-Loop Combo and other limited duration resources (incl. pumped storage)

28 $\Delta S_{s,h,r,i} = \min\left(ICap_{inj,i}(1 - EFORd_i), SCap_i - S_{s,h-1,r,i}\right)$

29 $\Delta S_{s,h,r} \mathrel{+}= \Delta S_{s,h,r,i}$

30 ***for i*** in storage assets: $S_{s,h,r,i} = S_{s,h-1,r,i} + \frac{\min(\Delta S_{s,h,r}, SDM_{s,h,r})}{SDM_{s,h,r}} \cdot \Delta S_{s,h,r,i}$ # pro-rata for each battery

31

32 ***else***
#Discharge/Withdraw

33 $DR_{s,h,r} = \min(A^{DR}_{s,h}, |SDM_{s,h,r}|)$,

34 $SDM_{s,h,r} \mathrel{+}= DR_{s,h,r}$

for i in storage assets ordered heuristically

If $SDM_{s,h,r} < 0$

if i in variable resource open loop:

$$\Delta S_{s,h,r,i} = \min\left(ICap^{wd}_{s,h,r,i}(1 - EFORd_i), SCap_i - S_{i,s,h,r}, |SDM_{s,h,r}|, \right)$$

if i in limited duration resources:

$$\Delta S_{s,h,r,i} = \min\left(ICap^{wd}_{s,h,r,i}(1 - EFORd_i), SCap_i - S_{i,s,h,r}, |SDM_{s,h,r}|, \right)$$

$$S_{s,h,r,i} = S_{s,h-1,r,i} - \Delta S_{s,h,r,i}$$

$$SDM_{s,h,r} \mathrel{+}= \Delta S_{s,h,r}$$

Else

Break

$LOLH_{s,h,r} = 1\{SDM_{s,h,r} < 0\}, EUE_{s,h,r} = \min\{SDM_{s,h,r}, 0\}$ # $1\{\cdot\} = 1$ when true and 0 otherwise

$LOLE_{s,r,d} = 1\{\sum_i^{24} LOLH_{s,i,r} > 0\}$ # for the hours in the same day, same load and performance scenario

$$LOLH = \frac{1}{403\times100}\sum_s^{403}\sum_h^{8760}\sum_r^{100} LOLH_{s,h,r},\ EUE = \frac{1}{403\times100}\sum_s^{403}\sum_h^{8760}\sum_r^{100} EUE_{s,h,r}\ ,\ LOLE = \frac{1}{403\times100}\sum_s^{403}\sum_d^{365}\sum_r^{100} LOLE_{s,d,r}$$

Appendix II: Indicative ELCC Values for ELCC Classes with No Class Rating

Figure 41 shows indicative ELCC values for ELCC Classes that do not receive an ELCC Class Rating at the time of this report. Please note that these values are based on an assumed resource mix, are non-binding, and provided only for informational purposes. The actual ELCC value of individual resources within these classes will be based on a resource-specific ELCC calculation and may materially differ from the class-wide or indicative hybrid values shown below. As such, no reliance shall be made on any of the indicative values shown in this Appendix II.

Figure 41. Indicative Values for ELCC Classes with No Class Rating

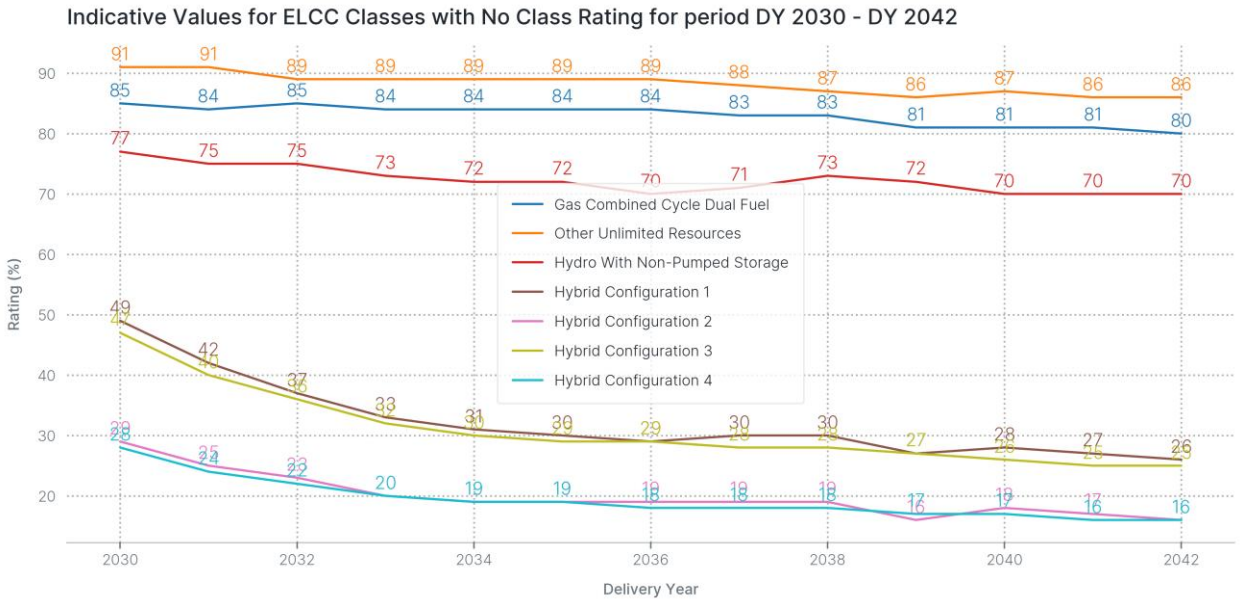


Table 37 depicts the configurations of the generic hybrids that were used to determine the indicative values in **Figure 41**. Due to the endless configuration possibilities, PJM selected a couple of various configurations based on the current interconnection queue projects.

Table 37. Generic Hybrid Configurations

Configuration	Project MFO	Project CIR	Fuel Type Component 1	ENC Component 1	Fuel Type Component 2	ENC Component 2
Hybrid Configuration 1	100	100	Solar Tracking	100	4-hr storage OL	100
Hybrid Configuration 2	100	100	Solar Tracking	100	4-hr storage OL	50
Hybrid Configuration 3	100	100	Solar Tracking	100	4-hr storage CL	100
Hybrid Configuration 4	100	100	Solar Tracking	100	4-hr storage CL	50

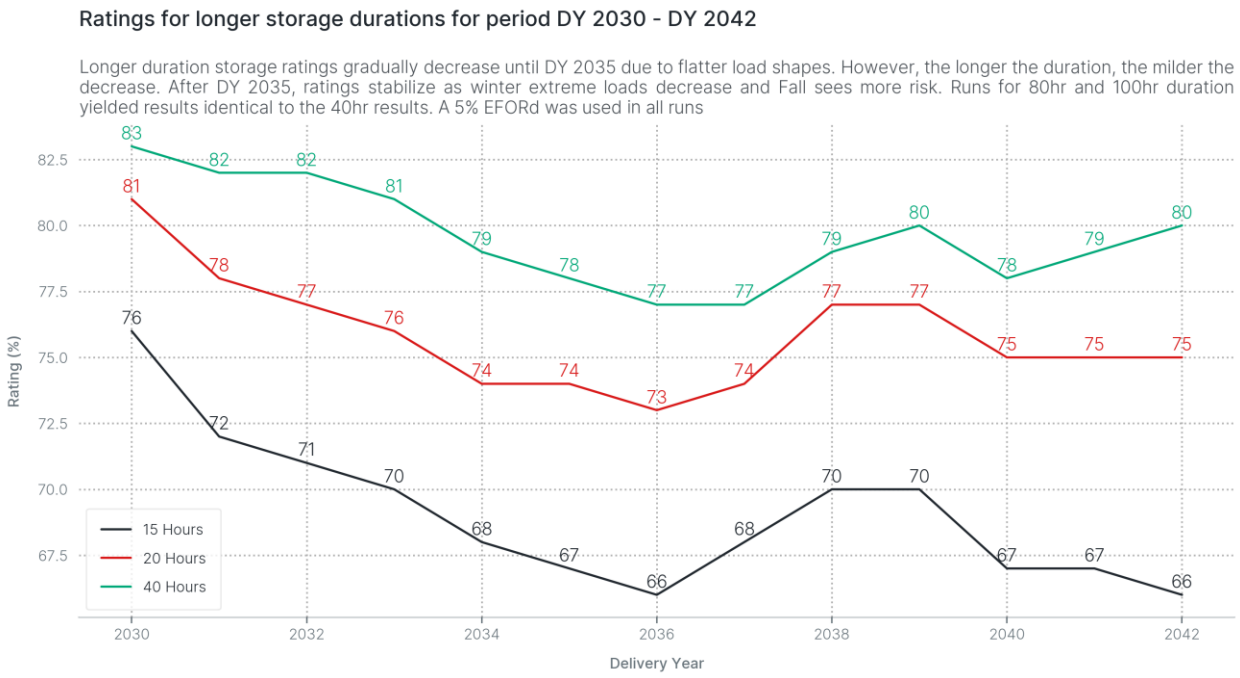
Appendix III: Indicative ELCC Values for Longer Duration Storage

Figure 42 shows indicative ELCC values for storage resources that have longer duration than the current Storage ELCC Classes in PJM. Please note that these values are based on an assumed resource mix, are non-binding, and provided only for informational purposes. Also, there is currently no established ELCC Class for these resources.

The runs were performed making the following assumptions:

- 5% EFORd
- 100% roundtrip efficiency
- Long duration storage was dispatched before the current storage ELCC classes but after Demand Response.
- Long duration storage was not allowed to charge the current storage ELCC classes

Figure 42. Ratings for Longer Duration Storage



Appendix IV: Sensitivities

Constant Large Load Additions

Description: This sensitivity is performed for 2029/30. All inputs remain identical to the 2029/20 BRA case except for the hourly load scenarios. The hourly load scenarios are modified so that the amount of new large loads is kept constant throughout the delivery year. This differs from the 2029/30 BRA case, which has new large loads being added throughout the delivery years (i.e. the amount of large loads that impact the winter hourly loads is greater than in the preceding summer)

Results:

As shown in **Table 38**, the IRM decreases due to lower extreme winter peaks as share of the 50/50 annual peak. The overall accreditation of the resource portfolio increases as shown by the increase in Pool-Wide Average UCAP Factor. The FPR increases because of higher accreditation of resources.

Table 38. Changes in IRM, Pool-Wide Average UCAP Factor and FPR in Constant Large Load Additions sensitivity

Metric	2029/30 BRA	2029/30 Sensitivity	Difference
IRM (%)	20.4	19.5	-0.9
Pool-Wide Average UCAP Factor	0.7668	0.7833	+0.0165
Forecast Pool Requirement (FPR)	0.9232	0.9360	+0.0128

Table 39 shows that the lower extreme winter peaks reduce the winter share of LOLE, LOLH and EUE. Also, LOLH and EUE decrease due to lower winter risk share.

Table 39. Changes in LOLE, LOLE Winter Share, LOLH, LOLH Winter Share, EUE and EUE Winter Share in Constant Large Load Additions sensitivity

Metric	2029/30 BRA	2029/30 Sensitivity	Difference
LOLE (days/year)	0.1	0.1	0
LOLE Winter Share (%)	77.9	60.4	-17.5
LOLH (hours/year)	0.377	0.328	-0.049
LOLH Winter Share (%)	89.4%	76.2%	-13.2
EUE (MWh/year)	2,183.7	1,625.1	-558.6
EUE Winter Share (%)	96.3%	89.3%	-7.0

Table 40 shows that the ELCC Class Ratings for most classes increase due to lower winter risk share. The only classes that show a lower ELCC Class Rating are Onshore Wind and Offshore Wind.

Table 40. Changes in ELCC Class Ratings in Constant Large Load Additions sensitivity

ELCC Class	2029/30 BRA Rating	2029/30 Sensitivity Rating	Difference
Onshore Wind	37%	35%	-2%
Offshore Wind	65%	60%	-5%
Fixed-Tilt Solar	6%	6%	0%
Tracking Solar	7%	9%	+2%
Intermittent Landfill Gas	50%	51%	+1%
Intermittent Hydropower	34%	34%	0%
Capacity Storage Resource (4-hr)	57%	66%	+9%
Capacity Storage Resource (6-hr)	66%	75%	+9%
Capacity Storage Resource (8-hr)	69%	76%	+7%
Capacity Storage Resource (10-hr)	76%	82%	+6%
Demand Resource	90%	93%	+3%
Nuclear	96%	96%	0%
Coal	84%	85%	+1%
Gas Combined Cycle	75%	77%	+2%
Gas Combustion Turbine	59%	63%	+4%
Gas Combustion Turbine Dual Fuel	76%	78%	+2%
Diesel Utility	92%	93%	+1%
Steam	75%	77%	+2%
Waste to Energy Steam	83%	84%	+1%
Oil-Fired Combustion Turbine	81%	83%	+2%

Excluding Load Scenarios derived with data from Weather Year 1993/1994

Description: This sensitivity is performed for 2029/30. All inputs remain identical to the 2029/20 BRA case except for the hourly load scenarios, which exclude those derived with weather data from delivery year 1993/1994. Winter of delivery year 1993/1994 was extremely cold RTO-wide.

Results:

As shown in **Table 41**, the IRM decreases due to removing load scenarios that drive risk in the base 2029/30 case. The overall accreditation of the resource portfolio slightly increases as shown by the increase in Pool-Wide Average UCAP Factor. The FPR slightly increases because of higher accreditation of resources.

Table 41. Changes in IRM, Pool-Wide Average UCAP Factor and FPR in Excluding Load Scenarios from Weather Year 1993/1994 sensitivity

Metric	2029/30 BRA	2029/30 Sensitivity	Difference
IRM (%)	20.4	19.5	-0.9
Pool-Wide Average UCAP Factor	0.7668	0.7738	+0.0070
Forecast Pool Requirement (FPR)	0.9232	0.9246	+0.0014

Table 42 shows that the removal of the load scenarios derived with weather year 1993/94, which includes an extremely cold winter, reduces the winter share of LOLE, LOLH and EUE. Also, LOLH and EUE decrease due to lower winter risk share.

Table 42. Changes in LOLE, LOLE Winter Share, LOLH, LOLH Winter Share, EUE and EUE Winter Share in Excluding Load Scenarios from Weather Year 1993/1994 sensitivity

Metric	2029/30 BRA	2029/30 Sensitivity	Difference
LOLE (days/year)	0.1	0.1	0
LOLE Winter Share (%)	77.9%	64.7%	-13.2%
LOLH (hours/year)	0.377	0.311	-0.066
LOLH Winter Share (%)	89.4%	77.6%	-11.8%
EUE (MWh/year)	2,183.7	1,406.2	-777.5
EUE Winter Share (%)	96.3%	88.9%	-7.4%

Table 43 shows that the ELCC Class Ratings for several classes increase due to lower winter risk share. The only classes that show a lower ELCC Class Rating are Onshore Wind, Offshore Wind and Intermittent Landfill Gas.

Table 43. Changes in ELCC Class Ratings in Excluding Load Scenarios from Weather Year 1993/1994 sensitivity

ELCC Class	2029/30 BRA Rating	2029/30 Sensitivity Rating	Difference
Onshore Wind	37%	35%	-2%
Offshore Wind	65%	58%	-7%
Fixed-Tilt Solar	6%	6%	0%
Tracking Solar	7%	8%	+1%
Intermittent Landfill Gas	50%	49%	-1%
Intermittent Hydropower	34%	38%	+4%
Capacity Storage Resource (4-hr)	57%	66%	+9%
Capacity Storage Resource (6-hr)	66%	76%	+10%
Capacity Storage Resource (8-hr)	69%	76%	+7%
Capacity Storage Resource (10-hr)	76%	82%	+6%
Demand Resource	90%	92%	+2%
Nuclear	96%	96%	0%
Coal	84%	84%	0%
Gas Combined Cycle	75%	75%	0%
Gas Combustion Turbine	59%	64%	+5%
Gas Combustion Turbine Dual Fuel	76%	78%	+2%
Diesel Utility	92%	92%	0%
Steam	75%	76%	+1%
Waste to Energy Steam	83%	84%	+1%
Oil-Fired Combustion Turbine	81%	81%	0%

2027/2028 Base Residual Auction (BRA) Cleared Resource Mix

Description:

This sensitivity was performed using the 2027/2028 BRA ELCC case, run in June 2025, with an updated resource mix that only included resources that cleared the 2027/2028 Base Residual Auction (BRA) or were included in a FRR plan. Overall, the updated resource portfolio resulted in a decrease of generation in the model of ~6,000 MW ICAP with about 52% of that from Unlimited Resources and 44% from Variable Resources. The level of Demand Response was updated to correspond to the cleared ICAP amount in the auction.

Results:

Table 44 shows that the IRM decreases due to the reduction in ICAP, as described above, which is greater than the reduction in the load level (i.e. solved load) that the updated portfolio was able to serve while meeting the 1 in 10 LOLE metric.

Table 44. Changes in IRM, Pool-Wide Average UCAP Factor and FPR in 2027/2028 BRA Cleared Resource Mix sensitivity

Metric	2027/28 BRA	2027/28 Sensitivity	Difference
IRM (%)	20.0	19.4	-0.6
Pool-Wide Average UCAP Factor	0.7717	0.7762	+0.0045
Forecast Pool Requirement (FPR)	0.9260	0.9268	+0.0008

Overall, the change in the resource portfolio is slightly increasing the risk in the winter period in all the metrics (LOLE, LOLH, and EUE) as shown in **Table 45**.

Table 45. Changes in LOLE, LOLE Winter Share, LOLH, LOLH Winter Share, EUE and EUE Winter Share in 2027/2028 BRA Cleared Resource Mix sensitivity

Metric	2027/28 BRA	2027/28 Sensitivity	Difference
LOLE (days/year)	0.1	0.1	0
LOLE Winter Share (%)	75.6%	76.0%	+0.4%
LOLH (hours/year)	0.352	0.362	+0.01
LOLH Winter Share (%)	86.9%	87.3%	+0.4%
EUE (MWh/year)	1,809.3	1,946.5	+137.2
EUE Winter Share (%)	95.4%	95.8%	+0.4%

As we see an increase in winter risk there can be a shift in the ELCC Class Ratings as well as shown in **Table 46**. For example, the wind classes' ratings increase in the sensitivity run. Additionally, there is a decrease in the storage ELCC Class Ratings due to the critical events in the winter period are generally longer in duration and do not allow charging to occur in between peaks at times. Note that not all the changes in ELCC rating can be explained by the increase in winter risk. Some ELCC rating changes are also impacted by changes in class membership.

Table 46. Changes in ELCC Class Ratings in 2027/2028 BRA Cleared Resource Mix sensitivity

ELCC Class	2027/28 BRA	2027/28 Sensitivity	Difference
Onshore Wind	41%	43%	+2%
Offshore Wind	67%	72%	+5%
Fixed-Tilt Solar	7%	7%	0%
Tracking Solar	8%	9%	+1%
Intermittent Landfill Gas	48%	47%	-1%
Intermittent Hydropower	39%	40%	+1%
Capacity Storage Resource (4-hr)	58%	56%	-2%
Capacity Storage Resource (6-hr)	67%	65%	-2%
Capacity Storage Resource (8-hr)	70%	68%	-2%
Capacity Storage Resource (10-hr)	78%	77%	-1%
Demand Resource	92%	92%	0%
Nuclear	95%	95%	0%
Coal	83%	83%	0%
Gas Combined Cycle	74%	75%	+1%
Gas Combustion Turbine	61%	62%	+1%
Gas Combustion Turbine Dual Fuel	77%	78%	+1%
Diesel Utility	92%	92%	0%
Steam	72%	72%	0%
Waste to Energy Steam	83%	83%	0%
Oil-Fired Combustion Turbine	80%	79%	-1%

2028/2029 Base Residual Auction (BRA) Cleared Resource Mix

Description:

This sensitivity was performed using the 2028/2029 BRA ELCC case, run in December 2025, with an updated resource mix that only included resources that cleared the 2028/2029 Base Residual Auction (BRA) or were included in a FRR plan. Overall, the updated resource portfolio resulted in a decrease of generation in the model of ~3,700 MW ICAP with about 11% of that from Unlimited Resources and 65% from Variable Resources. The level of Demand Response was updated to correspond to the cleared ICAP amount in the auction.

Results:

Table 47 shows that the IRM decreases due to the reduction in ICAP, as described above, which is greater than the reduction in the load level (i.e. solved load) that the updated portfolio was able to serve while meeting the 1 in 10 LOLE metric.

Table 47. Changes in IRM, Pool-Wide Average UCAP Factor and FPR in 2028/2029 BRA Cleared Resource Mix sensitivity

Metric	2028/29 BRA	2028/29 Sensitivity	Difference
IRM (%)	20	19.5	-0.5
Pool-Wide Average UCAP Factor	0.7834	0.7820	-0.0014
Forecast Pool Requirement (FPR)	0.9401	0.9345	-0.0056

Overall, the change in the resource portfolio is increasing the risk in the winter period in all the metrics below (LOLE, LOLH, and EUE) as shown in **Table 48**.

Table 48. Changes in LOLE, LOLE Winter Share, LOLH, LOLH Winter Share, EUE and EUE Winter Share in 2028/2029 BRA Cleared Resource Mix sensitivity

Metric	2028/29 BRA	2028/29 Sensitivity	Difference
LOLE (days/year)	0.1	0.1	0
LOLE Winter Share (%)	60.5%	65.4%	+4.9%
LOLH (hours/year)	0.348	0.357	+0.009
LOLH Winter Share (%)	76.6%	80.3%	+3.7%
EUE (MWh/year)	1,793.5	1,926.0	+132.5
EUE Winter Share (%)	90.2%	92.3%	+2.1%

Similarly to the 2027/2028 sensitivity above, as we see an increase in winter risk there can be a shift in the ELCC Class Ratings as well (see the wind classes' ratings increase in the sensitivity run) as shown in **Table 49**. Additionally, there is a decrease in the storage ELCC Class Ratings due to the events in the winter period are generally longer in duration and do not allow charging to occur in between peaks at times. Note that not all the changes in ELCC rating can be explained by the increase in winter risk. Some ELCC rating changes are also impacted by changes in class membership.

Table 49. Changes in ELCC Class Ratings in 2028/2029 BRA Cleared Resource Mix sensitivity

ELCC Class	2028/29 BRA	2028/29 Sensitivity	Difference
Onshore Wind	34%	37%	+3%
Offshore Wind	60%	66%	+6%
Fixed-Tilt Solar	7%	7%	0%
Tracking Solar	10%	10%	0%
Intermittent Landfill Gas	50%	49%	-1%
Intermittent Hydropower	35%	35%	0%
Capacity Storage Resource (4-hr)	59%	57%	-2%
Capacity Storage Resource (6-hr)	68%	65%	-3%
Capacity Storage Resource (8-hr)	71%	69%	-2%
Capacity Storage Resource (10-hr)	78%	77%	-1%
Demand Resource	91%	92%	+1%
Nuclear	96%	96%	0%
Coal	85%	85%	0%
Gas Combined Cycle	78%	78%	0%
Gas Combustion Turbine	67%	63%	-4%
Gas Combustion Turbine Dual Fuel	79%	78%	-1%
Diesel Utility	93%	93%	0%
Steam	75%	75%	0%
Waste to Energy Steam	84%	83%	-1%
Oil-Fired Combustion Turbine	83%	83%	0%

Appendix V: Supplemental Graphs Comparing the 2028/2029 BRA and 2029/2030 BRA runs

Figure 43. Effective Nameplate Capacity (ENC) and ICAP shares by resource category in the 2028/2029 BRA and 2029/2030 BRA runs

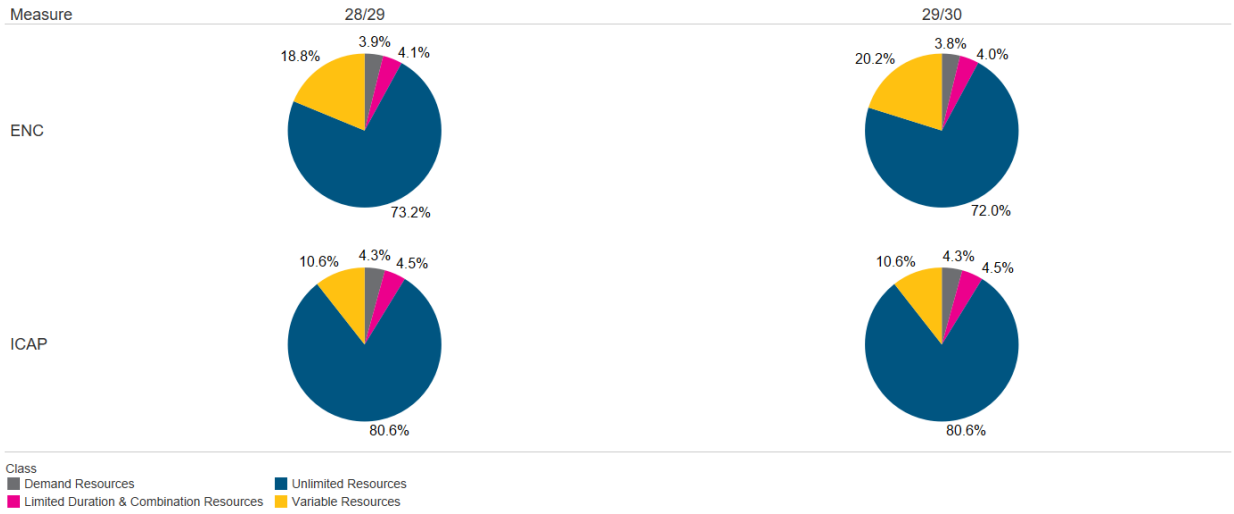


Figure 44. Share of Loss of Load Hours in for weather year and month combinations in the 2028/2029 BRA and 2029/2030 BRA runs (value in 2029/30 column is relative to the value in the 2028/29 column)

	January		February		March		June		July		August		December	
Weather Year	2028/29	2029/30	2028/29	2029/30	2028/29	2029/30	2028/29	2029/30	2028/29	2029/30	2028/29	2029/30	2028/29	2029/30
1993/1994	39.2%	-1.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
1994/1995	0.0%	0.0%	0.7%	+0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
1995/1996	0.2%	0.0%	1.1%	+2.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
1996/1997	7.2%	-2.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	5.2%	-2.6%	0.0%	0.0%	0.0%	0.0%
1997/1998	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
1998/1999	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
1999/2000	0.1%	+0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2000/2001	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.2%	-0.3%	0.0%	0.0%	0.0%	0.0%
2002/2003	1.2%	+0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	-0.1%	0.0%	0.0%
2003/2004	0.3%	+0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2004/2005	1.3%	+1.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2006/2007	0.0%	0.0%	0.5%	+0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2007/2008	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.0%	-1.5%	4.8%	-3.1%	0.0%	0.0%
2008/2009	3.2%	+0.7%	0.1%	+0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2011/2012	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%
2012/2013	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	9.4%	-4.5%	0.0%	0.0%	0.0%	0.0%
2013/2014	6.7%	+6.8%	0.3%	+0.3%	0.0%	0.0%	0.0%	0.0%	0.2%	-0.2%	0.0%	0.0%	0.0%	0.0%
2014/2015	0.7%	+1.2%	7.7%	0.0%	0.1%	+0.1%	0.0%	0.0%	0.4%	-0.3%	0.0%	0.0%	0.0%	0.0%
2015/2016	0.0%	0.0%	0.1%	+0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2016/2017	0.0%	+0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2017/2018	4.2%	+1.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2018/2019	1.3%	+0.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2020/2021	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2023/2024	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	+0.1%
2024/2025	0.4%	+0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Figure 45. Share of Loss of Load Hours by Hour Beginning in each season in the 2028/2029 BRA and 2029/2030 BRA runs

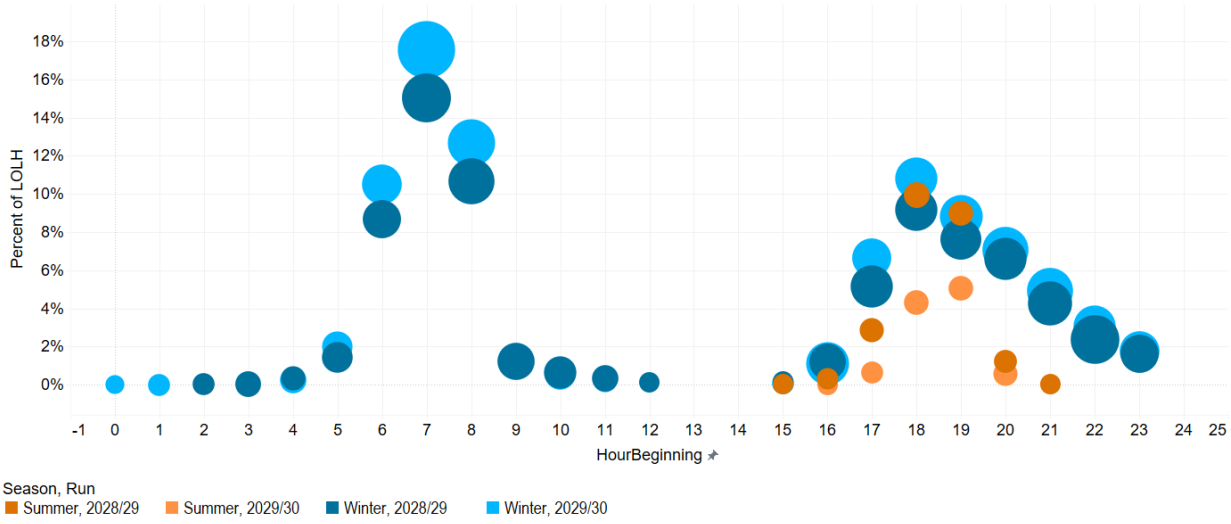


Figure 46. Boxplots for Total Supply (as share of total ENC/ICAP), Load (as share of respective forecasted median peak load) and Margin (in MW) in Loss of Load Hours in the 2028/2029 BRA and 2029/2030 BRA runs

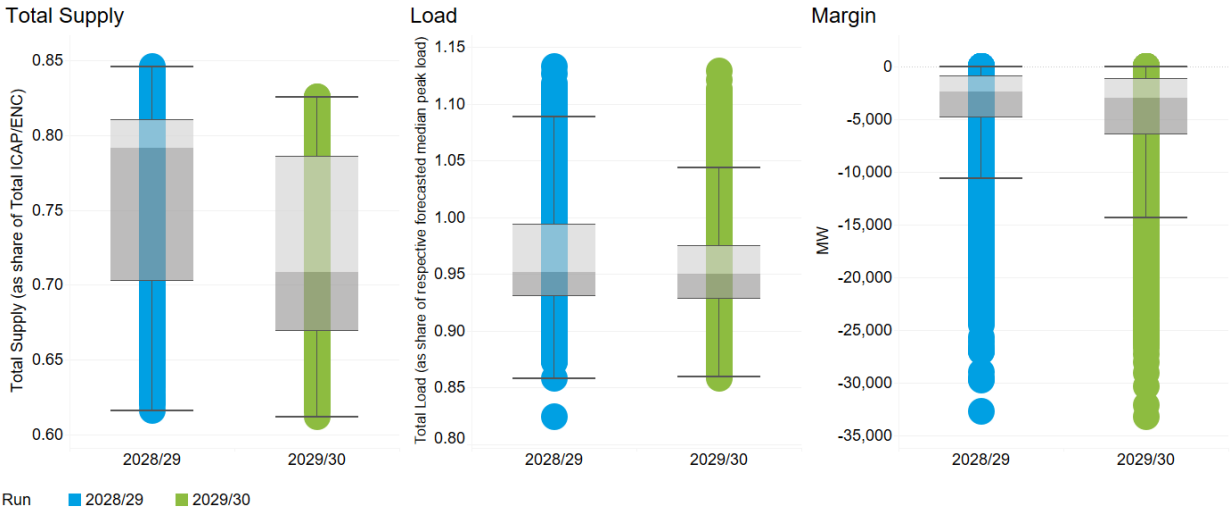


Figure 47. Boxplots for resource performance by resource category (as share of ENC or ICAP, as applicable) in Loss of Load Hours in the 2028/2029 BRA and 2029/2030 BRA runs



Appendix VI: Acronyms

The terms in this section are provided for the convenience of the reader and are in large part based on other sources, as indicated in the "Reference" column.

These references include the following:

- Mxx: PJM Manuals
- OA: Operating Agreement
- OATT: Open Access Transmission Tariff
- RAA: Reliability Assurance Agreement

Term	Acronym	Reference
Accrdited UCAP	AUCAP	RAA
Accredited UCAP Factor	AUCAP Factor	RAA
Base Residual Auction	BRA	OATT, M18
Accrdited UCAP	AUCAP	RAA
Accredited UCAP Factor	AUCAP Factor	RAA

Term	Acronym	Reference
Capacity Interconnection Rights	CIR	OATT, M21B
Delivery Year	DY	OATT
Demand Resources	DR	OATT, M18
Effective Load Carrying Capability	ELCC	RAA, M20A, M21B
Effective Nameplate Capacity	ENC	RAA, M21B
Expected Unserved Energy (MWh / year)	EUE	M20A
Forecast Pool Requirement	FPR	RAA, M20A
Installed Capacity	ICAP	RAA, M21B
Installed Reserve Margin	IRM	RAA, M20A
Loss of Load Probability	LOLP	M20A
Loss of Load Expectation (days / year)	LOLE	M20A
Loss of Load Hours (hours / year)	LOLH	M20A
Maximum Facility Output	MFO	OATT
Notice of Intent to Offer	NOI	OATT, M18
Reserve Requirement Study	RRS	M20A
Temperature Humidity Index	THI	M19