EOP Review Whitepaper Report

Objectives

The Emergency Operation Procedure ("EOP") whitepaper is part of the 5-year strategic plan for Resource Adequacy ("RA") modeling improvement. The purpose of the EOP whitepaper is to research how EOPs, especially Emergency Assistance ("EA"), are accounted for in the IRM base case model, and recommend changes that are appropriate.

The scope of the whitepaper includes 4 major questions:

- How EOPs, especially EA, are accounted for in the GE MARS model used in the IRM Study.
- How neighbors support NY during emergency conditions.
- The amount of assistance NY can rely on from neighbors during emergency conditions.
- The advancement of EA prior to the enactment of EOPs in the IRM study.

Based on the research, this whitepaper also recommends revising EA modeling used in the IRM study.

Background

The reliability of the Northeast regional power system heavily rely on the availability of support from across different systems and such support is modeled in the IRM study in the form of EA. The current EA assumptions in the IRM study are based on the knowledge and understanding that were established in 2020.[1] At the time, the regional system had relatively high reserve margins and experienced minimal changes in its supply mix. Since then, the Northeast regional system has undergone significant changes. Given the dynamic nature of the energy industry and resources, it is crucial to reassess these assumptions and update our understanding of the Northeast regional system.

The research methodology involves a comprehensive analysis of various factors that influence the effectiveness of EA assumptions within the IRM study simulation. The findings of such analysis were compared against the operation reality based on historical data and observation, as well as future expectations of adequacy conditions for the neighboring systems. These comprehensive reviews help update the understanding of the regional system's dynamics and determining whether adjustments are needed in the RA modeling assumptions. This process ensures that the EA assumptions align with the current realities of the evolving energy industry and grid operation, enabling effective planning and management of the regional power system.

[1] https://www.nysrc.org/wp-content/uploads/2023/03/External-Area-Whitepaper.pdf

Review the Current Assumptions in the IRM Simulation

The review utilizes the output from the General Electric ("GE") Multi-Area Reliability Simulation ("GE MARS") to examine the availability and behavior of EA flows from external areas. In the current IRM assumptions, EA from the external areas is characterized by a set of restrictions:

- The interties remain open until EOP step 8, and the transfer capabilities of individual interties are determined based on the data available in the NPCC database.
- Priority of EA providers are in the order of IESO, HQ, ISONE, and PJM.[2]
- A global limit of 3,500 MW is placed on the total amount of EA that can be received from external areas at any given event. This limit ensures that the assistance remains within manageable bounds.
- Policy 5 requirements: External area modeling for EA must comply with the guidelines specified in Policy 5. This policy mandates aligning the top three peak load days of external areas with those of NYCA. Additionally, it stipulates that generation and load balancing in the external areas should not exceed their respective RA criteria, such as Loss of Load Expectation ("LOLE") and referenced margin.

The review also examines differences between different Load Forecast Uncertainty ("LFU") bins, which represent different levels of severity of weather conditions and associated probability of occurring.

The data analysis reviewed the frequency and magnitude of EA flows during the simulated Loss of Load events, as well as the composition of EA when needed. The following observations are made based on the data analysis:

- Maximum EA, i.e., 3500 MW, is reached under LFU bin 1-3; under LFU bin 4 which represents normal weather condition, maximum about 1000 MW EA is required.
- More EA flows exist in upper LFU bins, compared to lower LFU bins, in terms of both frequency and magnitude.
- IESO and ISONE are the main providers of EA during the simulation. Under more severe weather conditions, i.e., LFU bin 1, EA from IESO and ISONE is replaced by PJM.
- EA from HQ is constantly maxed out at 280 MW which is the limit implemented in the IRM study assumption to account for firm imports from HQ.

The following figures show the EA flow distribution during LOLE and composition of EA flows during top LFU bins based on the 2023-2024 IRM Final Base Case. Refer to Appendix 1 for details on other statistics of EA flows in the IRM simulation.

[2] The EA priority order as input in the model drives down the significant reliance on PJM, especially for lower Bins, but does not impact system LOLE or the IRM.

Figure 1 – EA Flow Distribution during LOLE

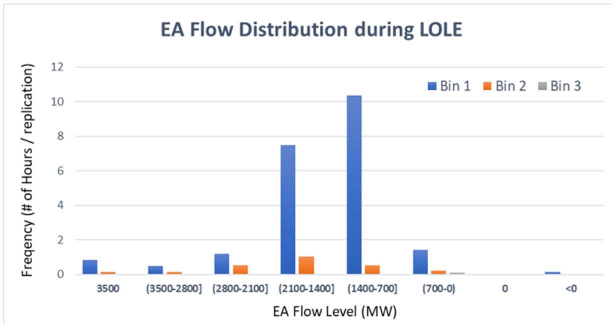
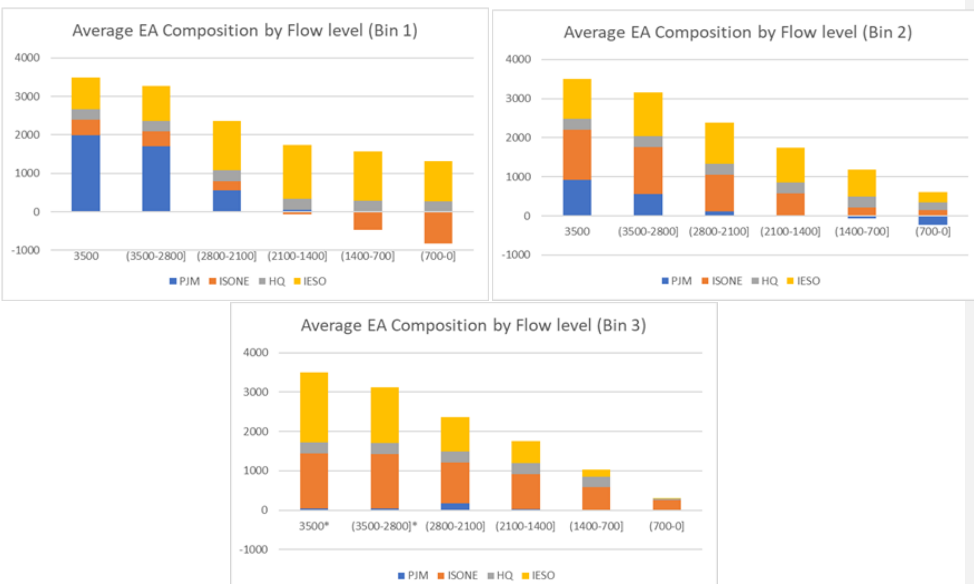


Figure 1 - EA Flow Composition in Top LFU Bins



Review the Recent Operational Experience and Future RA Outlooks of the External Systems

Historical Review

Understanding the recent real-time operational experience plays a crucial role in understanding Northeast regional system's dynamics. It is important to note that the Grid Operations statistics are based on actual historical load data and may not align with the at-criteria MARS simulation. The Grid Operations have not encountered LFU Bins 1, 2, or 3 summer loads over the past several years.

The analysis based on historical observation of transactions with externals during peak day operation for the past few years shows that NYCA's summer peak load days coincides with ISONE and IESO. PJM's summer loads do not always coincide with NYCA, so it allows NYCA to rely on PJM more during summer peak load days. Hence, during tight operation conditions, PJM is the primary supplier of imports during peak days, followed by IESO and HQ. In contrast, NYCA tends to export to ISONE during these events regardless of the season. See Table 1 below.

Table 1 – Historical NYCA Peak Load Days Coinciding with Neighbors

Neighboring ISO/RTO	IESO	PJM	ISONE
Summer	67%	50%	100%
Winter	83%	33%	100%

Future Outlook Review

To enhance the understanding of the dependency between NYCA and its neighboring systems, the assessment of the outlook of external areas was conducted based on the NPCC seasonal assessment and the NERC long-term assessment.

In the short-term, while the NPCC region appears to be adequate from the overall region basis, some areas are showing tight operating conditions during beyond-the-average weather conditions. For example, the NPCC 2023 Summer Assessment[3] shows low and negative operating margins for various regions. While low operating margins do not mean load shedding and only indicate the potential need to rely on operating procedures and external supports, low margins across multiple regions could lead to reduced support for each other.

Over the longer term, the resource adequacy outlook of each external region surrounding the NYCA is important to indicate their ability to provide support to NYCA during emergency conditions. Based on the review of the NERC Long-Term Reliability Assessment,[4] the region is showing varying risk levels and adequacy challenges for IESO, ISONE, and HQ in the future.

- IESO is identified as a high-risk area for not meeting RA criteria due to a significant shrinkage in its reserve margin over the next decade.

[3] https://www.npcc.org/content/docs/public/library/reports/seasonal-assessment/2023/npcc-2023-summer-reliability-assessment.pdf

[4] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf

- ISONE is identified as an elevated-risk area for potential shortfalls during extreme conditions.
- HQ poses no regional risk during the summer, due to its winter peaking system, but experience growing winter demand.
- PJM currently faces no immediate risk.

Winter Consideration

The Northeast region has been focused on reliability during summer season due to summer peaking nature of the region. Except for Quebec, New York, New England, Ontario and PJM regions have been summer peaking in the past years. However, most of the regions start to experience tight winter operating conditions and some regions are expected to switch to winter peaking system by the end of this decade.

- NPCC's 2022-2023 Winter Assessment shows low margins in New England and Quebec beyond the 50/50 forecast level.
- IESO's 2022 Annual Planning Outlook shows switching to winter peaking in the mid-2030s.
- PJM recently announced significant shift in reliability risk to the winter based on preliminary analysis.

In summary, the external area review demonstrates tighter conditions and increased risk across the entire region, as shown in table 2 below. Details of the external area review can be found in Appendix 2.

Table 2: External Area Review for Winter Considerations

External Area	Summary
IESO	•Identified as High-Risk area for not meeting RA Criteria •Reserve Margin shrinks significantly in the next 10 years •Short-term reliability relies largely on imports from other areas •When NYCA experiences harsh weather condition, IESO is likely to experience similar condition
	<u>Winter Consideration</u>: IESO is expected to turn into winter peaking in the mid-2030s
ISONE	•Identified as Elevated Risk area for being at risk of shortfall during extreme conditions •Short-term reliability relies largely on imports from other areas
	<u>Winter Consideration</u>: On-going concern with fuel availability during extended cold spell
HQ	•No regional risk identified in the summer due to winter peaking •Main source of emergency support during summer for Northeast region •Reached all-time summer peak in August 2021 and expect to set summer peak record in 2023
	<u>Winter Consideration</u>: Requires support from the Northeast region during winter season
PJM	•No immediate regional risk identified, •Low penetration of limited and variable resources •Thermal resources are under environmental regulation pressure •Long-term projection suggests difficulty keeping up with expected demand growth by 2030 •Recent market issues
	<u>Winter Consideration</u>: Recently announce shift of reliability risk to winter season

Conclusion

Based on the review of IRM database, historical grid operations data, as well as the conversation with the neighboring systems, it is concluded that the current EA assumptions in the IRM study are too optimistic, and that further restrictions in the EA limit should be implemented.

- Substantial amount of EA is required in the IRM study, mainly from IESO and ISONE
- During real time operations under tight conditions, PJM can provide primary support to NYCA while NYCA typically exports to support ISONE.
- Tight supply conditions are expected across all Northeast region, especially for IESO in the summer and ISONE / HQ during winter.

In addition, supply mix changes across all neighboring jurisdictions lead to further downward pressure on systems' resource adequacy conditions as traditional thermal fleet is replaced by intermittent resources. Concerns over winter also start to emerge across the Northeast region as several systems are showing tight conditions during winter seasons.

Coordination on EA assumptions with external areas has also been conducted, via outreach and research on external areas' EA assumptions in their respective RA models. In general, the neighboring systems have more conservative, i.e., lower, EA assumptions in their RA model and both ISONE and PJM expressed desire to further lower their EA assumptions. See Table 3 below for EA assumptions in other RA models.

Table 3 - EA Assumptions in Other RA Models

External Area	EA/Tie Benefits – 2015 Whitepaper	Update/Expected Trend
IESO	0 MW	Unchanged
ISONE	1,624 MW	2,100 MW for FCA 17: Currently reviewing Tie Benefits study methodology
HQ	1,100 MW	1,600 MW[5]
PJM	3,500 MW	Unchanged

Modeling Options and Considerations

To improve the IRM modeling with more limited EA assumptions, 4 options have been considered:

1. Improve the external area data to reflect more detailed representation of the external systems
2. Increase the targeted LOLE for external area under Policy 5 adjustment (e.g., 0.2 LOLE instead of 0.1 LOLE)
3. Include EOPs in external area modeling during Policy 5 adjustments, and then removing the EOPs after implementation of Policy 5 adjustments
4. Implement additional limits on topology to restrict EA flows

[5] file://hpcfs1.ad.aws1.nyiso.com/HPCCloud-Capacity/IRM/Whitepapers/EOP/Background/2021-12-31-review-of-interconnection-assistance-reliability-benefits.pdf

To screen these modeling options, 5 factors were considered:

- Feasibility: is the modeling option possible to implement in the IRM model?
- Seasonality: is the modeling option possible to support winter modeling?
- LFU Bin Specific: is it possible to accommodate different assumptions for different weather conditions, i.e. LFU bins?
- Goal of Policy 5: is the modeling option going to achieve the goal of Policy 5 of avoiding overdependence on external areas given the current modeling provides too optimistic EA support in the IRM simulation?
- Justifiable and Repeatable: is the modeling based on a set of analysis or processes that can be repeated over time?

Table 4 – Modeling Considerations

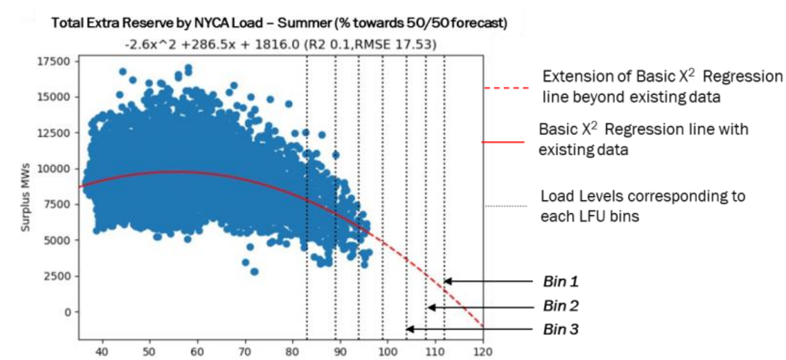
Options / Considerations	**1.Improve Data** *Get better data and more detailed external data*	**2.Increase LOLE** *Model the external area at higher LOLE*	**3.Model EOPS** *Include the EOPS in the external areas during Policy 5*	**4.Toplogy Limits** *Add limits to transfer capabilities into NYCA*
Feasibility	-Limited control over source data -Lead time required to coordinate -Not able to replicate external's own RA study	-Can be implemented easily	-Can be implemented if EOP data is available	-Can be implemented easily
Seasonality	-Depends on the seasonal representation of external data	-The annual LOLE criteria will not facilitate seasonal assumptions	-The EOP steps are applied annually and will not facilitate seasonal assumptions	-Topology limits can be seasonal specific
LFU Bin Specific	-Depends on the LFU bin specific modeling in external data	-The annual LOLE criteria will not facilitate LFU bin specific assumptions	-LFU bin specific assumption can be facilitated if structured in the EOP data -Same application across all LFU bins is the current default	-Topology limits can vary by LFU bins
Goal of Policy 5	-May not address the issue of overly optimistic EA support in the current model	-Likely address the issue of overly optimistic EA support in the current model	-Including EOPs will result in holding more MW in external areas (except for IESO) and therefore will lead to more optimistic EA support compared to the current model	-Likely address the issue of overly optimistic EA support in the current model
Justifiable and Repeatable	-Owners are on the external areas to submit representative data	-Higher than required criteria is arbitrary	-Owners are on the external areas to provide up to date EOP data	-Depends on the analysis supporting the additional topology limits

Based on the screening from the 5 considerations, modeling option 4 is recommended to proceed with further development.

Modeling Inputs Development

To provide emergency assistance to an external system, it is expected that the area will need to have available MW from reserves, in the amount above the area's operating reserve requirement. Therefore, historical hourly extra reserve data for each of the external jurisdictions is extracted for the period between 2021 and April 2023. The hourly extra reserve data is then aligned with the NYCA hourly load for regression analysis. Relationship between the hourly extra reserves and NYCA load is established using Basic X^2 Regression and the regression relationship is then further extended rightwards to arrive at potential input assumptions for higher NYCA load levels that correspond to each LFU bin in the IRM model. The analysis is demonstrated in figure 3 below:

Figure 3: Total Extra Reserve by NYCA Load



The exercise is performed for all the individual external areas with extra reserves data, as well as the total combined reserves from all areas. The intersections of the regression line and the calculated load levels for each bin become the area- and LFU bin-specific EA limits.

Analysis with extra reserve data during winter season, as well as analysis using historical NPCC seasonal operating margins were also conducted. However, the NPCC data does not include assessment for PJM and the data analysis did not arrive at meaningful modeling inputs for the revised EA modeling. Details of the data analysis for modeling inputs are available in Appendix 3.

Table 5 below summarized the modeling inputs for additional topology limits to restrict EA flow in the IRM study. As no winter-specific inputs were developed, modeling inputs based on assessment with the summer data are applied for the winter season.

Table 5 – Additional topology limits to restrict EA flows

Area	Bin 1	Bin 2	Bin 3	Bin 4	Bin 5	Bin 6	Bin 7
IESO	550 MW	660 MW	750 MW	860 MW	No additional limits (1950/2100 MW)		
ISONE	50 MW	540 MW	1,000 MW	1,530 MW	No additional limits (1804 MW)		
PJM	580 MW	1,110 MW	No additional limits (1412 MW)				
HQ	No additional limits (280/1162 MW)						
Total	1,470 MW	2,600 MW	No additional limits (3500 MW)				

Impact Assessment

Preliminary impact analysis was conducted on the 2023-2024 Final Base Case. Implementing the recommended EA modeling results in about 2% increase in the IRM and minimum change in the LCRs.

Table 6 – Impact of the Initial Recommendations

Tan45 Results	***IRM***	***J LCR***	***K LCR***
2023-2024 IRM FBC	19.90	78.20	107.40
2023-2024 IRM FBC + Recommended EA modeling	21.91	77.862	107.065
Delta	*2.01*	*-0.338*	*-0.335*

Additional sensitivity with the recommended EA modeling was conducted on the 2024-2025 Preliminary Base Case, and similar impacts were observed. Annual EOP calls, LOLH and EUE statistics, with no major movement observed, were also collected from the sensitivity results.

Table 6a – Impact of the Initial Recommendations

Tan45 Results	**2024 - 2025 PBC**	**2024 - 2025 PBC + recommended EA modeling**	***Delta % (ICAP) from PBC***
IRM	20.800%	23.043%	*+2.243% (+727.9 MW)*
J LCR	72.719%	72.405%	*-0.314% (-35.5 MW)*
K LCR	109.880%	109.524%	*-0.356% (-18.1 MW)*
GRP G-J	84.252%	84.022%	*-0.230% (-35.5 MW)*
NYBA EOP (Days/Year)	7.552	6.158	*-1.394*

Table 6b – Impact of the Initial Recommendations

Case	**LOLE**	**LOLH**	**Normalized LOEE (EUE) "Simple Method" ppm**	**Normalized LOEE (EUE) "Bin Method" ppm**
2024-2025 PBC	0.100	0.337	1.188	1.031
2024-2025 PBC + recommended EA modeling	0.100	0.368	1.498	1.292

Model behavior was also reviewed by analyzing EA flow data as output from the sensitivity case simulation. The recommended EA modeling also achieved the objectives of lowering overall EA and reducing reliance on IESO / ISONE at upper LFU bins. Details of the model behavior analysis are available in Appendix 4.

Recommendations

Based on the conclusion from reviewing the IRM simulation as well as the external areas, adopting the additional area- and LFU bin specific limits on EA, as detailed in the following table, is recommended.

Table 7 – Recommendations based on IRM simulation

Area	Bin 1	Bin 2	Bin 3	Bin 4	Bin 5	Bin 6	Bin 7
IESO	550 MW	660 MW	750 MW	860 MW	No additional limits (1950/2100 MW)		
ISONE	50 MW	540 MW	1,000 MW	1,530 MW	No additional limits (1804 MW)		
PJM	580 MW	1,110 MW	No additional limits (1412 MW)				
HQ	No additional limits (280/1162 MW)						
Total	1,470 MW	2,600 MW	No additional limits (3500 MW)				

However, these assumptions for EA limits will need to be updated regularly in order to reflect changing conditions on the Northeast interconnected system. The following process is also recommended to be implemented:

- For the next two years, repeat the regression analysis with historical extra reserves data for any potential updates to the IRM study assumptions.
    - To maintain reasonable stability of the IRM study, the EA assumptions are only updated if the regression analysis results in changes that are ≥ 25 MW.
- Continue to explore methodologies to develop winter-specific EA assumptions.
- Leverage regional collaboration and neighboring areas progress with emergency assistance assumptions to review or improve the current methodology beyond 2024.
    - Participate in the NPCC working group and support the working group effort to improve regional tie-benefits study.
    - Continue the conversation and collaboration with the neighboring systems, such as PJM and ISONE, to monitor their progress in revising their adequacy study assumptions for emergency assistance.

Consideration for Advancing EA prior to EOPs

Advancing EA prior to EOPs will result in more optimistic support from the external areas during the IRM simulation, therefore such treatment will offset some level of conservatism in the recommended EA modeling. In addition, advancing EA prior to EOPs can potentially improve the current ELR functionality. However, the effect of such treatment will need to be assessed in conjunction of potential changes to the SCR modeling as part of a separate NYISO project.

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Therefore, it is recommended not to consider advancing EA prior to EOPs in the IRM model at this point. Additional review can be resumed in the future when the SCR modeling is revised.

Appendix 1 – Review of Current Assumptions in the IRM Simulations

During GE MARS simulations, EA flows from external areas are available only when the following conditions are met:

- Deficiencies in NYCA are not addressed by the first seven steps of the EOP.
- When the interties are closed, the external jurisdictions have surplus generation.
- Flows of EA from a given jurisdiction are limited by the intertie capabilities.
- The total flows of EA from all external jurisdictions do not exceed the global limit of 3,500 MW.

In numerous instances,[6] the EA flows at and after EOP step 8 successfully mitigate the risk and NYCA deficiencies, avoiding potential loss of load events. But EA continues to exist during loss of load event when deficiencies in NYCA cannot be addressed.

Another key area to understand in this analysis is the difference between different Load Forecast Uncertainty ("LFU") that are modeled in the IRM studies. There are seven different load levels, also known as bins. These bins represent different uncertainties of load by the variabilities in peak weather conditions, and each bin is assigned with a certain probability within the simulation. The analysis demonstrates a strong correlation between EA flows and the assigned LFU bins. By categorizing system conditions into different LFU bins, the study identifies distinct patterns in EA flows and their relationship with the frequency of loss of load events. LFU Bin 1, representing the most severe weather conditions (1 in 160-year), is assigned with the lowest probability of occurrence. Bin 2 represents 1 in 15-year hot peak day, and Bin 3 is where the 90/10 forecast can be observed. Bin 4 represents the 50/50 forecast and is associated with the highest probability of occurrence. Bin 5-7 represent lower than average peak weather condition. The probabilities of each Bin occurring are listed in *Table 8* below.

Table 8 – Probabilities of Occurrence for each LFU Bin

LFU Bin	1	2	3	4	5	6	7
Probability of Occurrence	0.62%	6.1%	24.2%	38.3%	24.2%	6.1%	0.62%

The research findings indicate that during LFU Bin 1, NYCA requires an average of 21.98 hours of EA. Conversely during Bin 3 and below, the expected hours of assistance are less than 1 hour. This demonstrates the severity of assistance during LFU Bin 1, and the relative stability during Bins 3 and below. The analysis reveals that in LFU Bins 1-3, NYCA requires the full external assistance of 3,500 MW. However, in Bins 4 / 5, while some assistance is necessary, the flow does not reach the maximum level.

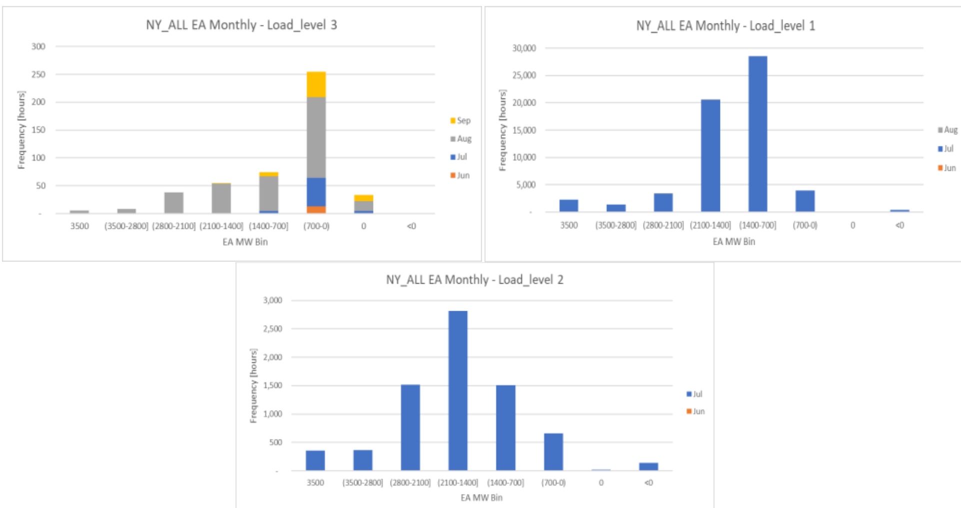
Table 9 - EA Flow Level by LFU Bin

LFU Bins	MAX EA (MW)	Expected Hours with EA (hours)
Bin 1 [1 in 160 years]	3500	21.98
Bin 2 [1 in 15 years]	3500	2.68
Bin 3 [1 in 3 years]	3500	0.17
Bin 4 [Expected Load]	995	0.02
Bin 5	404	<0.01
Bin 6	0	0
Bin 7	0	0

[6] During IRM simulation, EA is utilized to avoid over 1/3 of the loss of load events.

Further analysis reveals that NYCA does not consistently require the maximum EA of 3,500 MW during LFU Bins 1-3. Instead, most EA flows fall within the range of 700 MW to 2,100 MW during Bins 1 and 2, and between 0 MW to 700 MW during Bin 3. Maximum assistance is needed only for small percent of time. Figure 4 below shows the frequency of EA during loss of load at different flow levels.

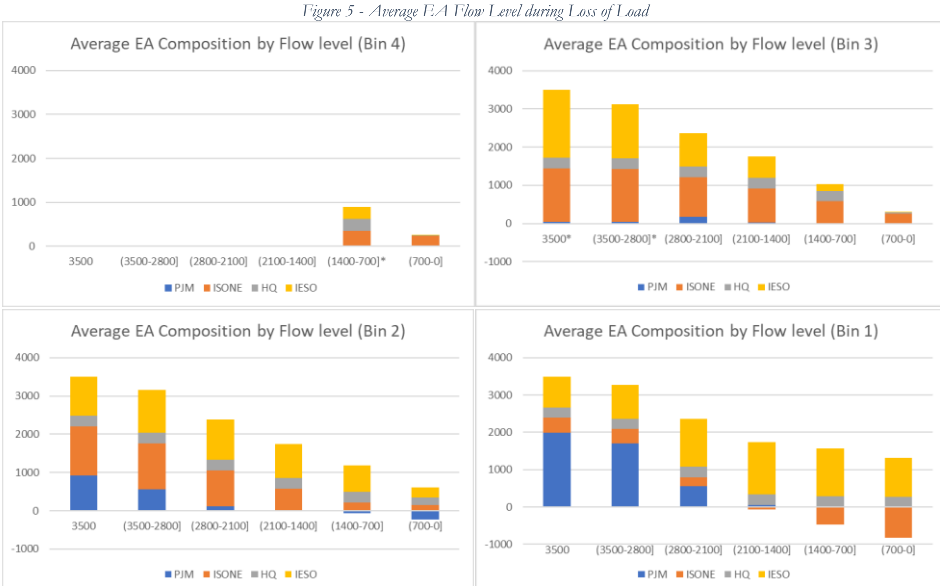
Figure 4 - Distribution of EA during Loss of Load 7



The composition of EA from which NYCA receives assistance during loss of load events is a critical factor in assessing the effectiveness and impact of external support. On average, NYCA relies heavily on assistance from IESO and ISONE. The priority order input assumption ensures a consistent flow of EA from IESO, while ISONE provides higher support at lower flow levels, whereas the support from HQ remains consistent. In scenarios where the EA flow reaches higher levels, particularly in the top LFU bins, the support from PJM becomes critical. PJM bridges the assistance gap when both IESO and ISONE are likely experiencing the similar extreme conditions, ensuring continuous support to NYCA. Figure 5 below shows the average composition of EA during loss of load, at different flow levels.

[7] The graphs are based on the raw data across 2,750 replications. The graphs are to represent the flow distribution of EA at different LFU Bins, and are not on the same scale.

Figure 5 - Average EA Flow Level during Loss of Load



<u>Appendix 2 – Review of the Recent Interaction and RA Conditions of the External Systems</u>

The NPCC 2023 Summer Assessment shows low and negative operating margins for IESO and ISONE at all forecast levels (see table 10 & 10a below).

Table 10 – New England Operating Capacity Forecast[8]

Week Beginning June 25, 2023	50/50 Forecast	90/10 Forecast	Above 90/10 Forecast
Installed Capacity (+)	28,869	28,869	28,869
Net Interchange (+)	1,030	1,030	1,030
Dispatchable DSM (+)	447	447	447
Total Capacity	30,346	30,346	30,346
Peak Demand Forecast (-)	24,664	26,479	28,154
Interruptible Load (+)	0	0	0
Known Maintenance & Derates (-)	346	346	346
Operating Reserve Requirement (-)	2,305	2,305	2,305
Unplanned Outages (-)	2,800	2,800	2,800
Operating Margin	231	-1,584	-3,259
Operating Margin (%)	0.9	-6.0	-11.6

[8] https://www.npcc.org/content/docs/public/library/reports/seasonal-assessment/2023/npcc-2023-summer-reliability-assessment.pdf

Table 10a - Ontario Operating Capacity Forecast[8]

Summer 2023	50/50 Forecast	90/10 Forecast	Above 90/10 Forecast
Installed Capacity (+)	38,273	38,273	38,273
Net Interchange (+)	223	223	223
Dispatchable DSM (+)	687	687	687
Total Capacity	39,183	39,183	39,183
Interruptible Load (+)	0	0	0
Known Maintenance & Derates (-)	13,690	14,722	14,722
Operating Reserve Requirement (-)	1,401	1,401	1,401
Unplanned Outages (-)	1,565	873	873
Peak Load Forecast (-)	22,439	24,420	27,021
Operating Margin	88	-2,438	-5,058
Operating Margin (%)	0.4	-10.0	--18.7

In the NERC 2022 Long-Term Reliability Assessment[9] highlights risks across the regions:

- IESO is identified as a high-risk area for not meeting RA criteria due to a significant shrinkage in its reserve margin over the next decade. The region's short-term reliability depends heavily on imports from other areas. Given the similarities in weather conditions between IESO and NYCA, emergency situations in NYCA are likely to be mirrored in IESO. Additionally, IESO is expected to turn into a winter peaking system in the late 2020s.
- ISONE is identified as an elevated-risk area for potential shortfalls during extreme conditions. Like IESO, its short-term reliability heavily depends on imports from other regions. Notably, ISONE faces ongoing concerns with fuel availability during extended cold spells, adding to the potential challenges during emergencies.
- HQ poses no regional risk during the summer, due to its winter peaking system. It serves as the main source of emergency support for the Northeast region during the summer months. However, the region experienced an all-time summer peak in August 2021, and is expected to set another peak record in 2023. During winter, HQ requires support from the Northeast region.
- PJM currently faces no immediate regional risk. However, it has a low penetration of limited and variable resources and is under environmental regulation pressure concerning thermal resource. Long-term projections suggest PJM may struggle to keep up with expected demand growth by 2030, raising concerns about resource adequacy in the future. Recent market issues further highlight the importance of assessing PJM's support capabilities to NYCA.

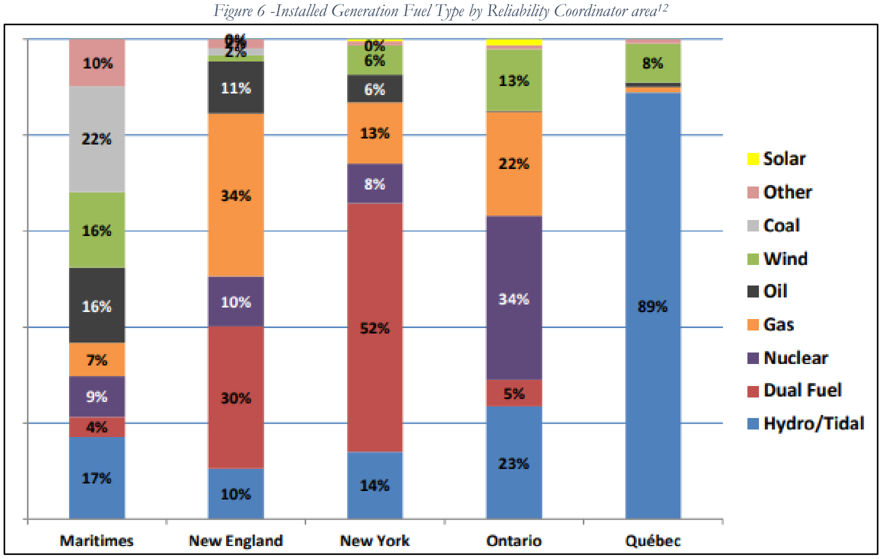
Some regional neighbors are either a winter peaking system or are forecasted to become a winter peaking system in the coming years. NPCC's most recent winter assessment (2022-2023)[10] shows low margins in New England and Quebec, beyond 50/50 load forecast levels.

An MMU analysis of New England found that fuel deliverability risk for gas generators is one of the factors impacting New England's winter margin under moderate weather conditions. Energy security risks in New England are well-documented, with heightened concerns this winter due to sharp increases

[9] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf
[10] https://www.npcc.org/content/docs/public/library/reports/seasonal-assessment/2022/npcc-winter-2022-2023-assessment.pdf

in global energy demand, supply chain contraction and retirement of fuel-secure generators are a consideration for New England. [11] Similar consideration is also applicable for the entire northeast region. Figure 6 depicts northeast region's installed generation resource profile; ISONE has the largest reliance on gas compared to other NPCC regions. Long-duration Energy Emergencies could have far more serious consequences to residents and the economy than a capacity deficiency for ISONE.

Figure 6 -Installed Generation Fuel Type by Reliability Coordinator area[12]



- For the past two years, Quebec set two all-time demand records during the winter season (40,500 MW in 2022 and 42,700 MW in 2023) and frequently requires external support during the winter season. This fact is supported by how Hydro-Quebec winter peaking load is almost two times the historical summer peaking load.[9]
- PJM announced a significant shift in reliability risk to the winter based on preliminary analysis with updated reliability risk modeling. [13]
- IESO's 2022 Annual Planning Outlook suggests a transition to a winter peaking system in the early 2030s and can be further advanced with significant electrification uptake in the industrial sector. IESO was originally forecasted to continue to be a summer peaking system beyond 2040 in the 2021 Planning Outlook. [14]

[11] https://www.npcc.org/content/docs/public/library/reports/seasonal-assessment/2023/npcc-2023-summer-reliability-assessment.pdf
[12] Figure 6 depicts installed generation resource profiles for each Reliability Coordinator area and for the NPCC Region by fuel supply infrastructure as projected for the NPCC coincident peak week
[13] https://www.pjm.com/-/media/committees-groups/cifp-ra/2023/20230530/20230530-item-03---reliability-risk-modeling.ashx slide 15
[14] https://www.ieso.ca/en/Sector-Participants/IESO-News/2022/12/2022-Annual-Planning-Outlook

Figure 7: PJM Preliminary Analysis Indicates Shifting Risks to winter[15]

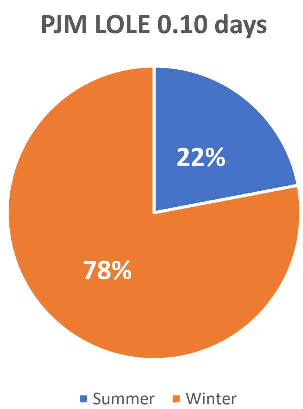


Table 11 - All-Time Winter Peak Demand by Area[16]

Reliability Coordinator Area	Load (MW)	Date and Time
Maritimes	5,733	January 27, 2022, HE8 EST
New England	22,818	January 15, 2004, HE19 EST
New York	25,738	January 07, 2014, HE19 EST
Ontario	24,979	December 20, 2004, HE18 EST
Quebec	40,410	January 27, 2022, HE08 EST

The emergency operating procedures considers seasonal similarities between the Northeast regional power system to ensure the stability of the grid during peaking conditions. Each reliability coordinating area overlaps with at least one other region that experiences peaking season conditions.

Appendix 3 – Data Processing for Modeling Inputs

Processing the Extra Reserves Data

Multiple analyses were conducted to produce appropriate modeling input. The main analysis involved using the hourly extra reserve data from the external areas between 2021 and April 2023.

- For IESO and ISONE, the data for hourly surplus reserves is available. For IESO, the data is further adjusted to account for impacts from Demand Response program, based on the reported hourly program impact during the peak load days.

[15] https://www.pjm.com/-/media/committees-groups/cifp-ra/2023/20230530/20230530-item-03---reliability-risk-modeling.ashx slide 09

[16] https://www.npcc.org/content/docs/public/library/reports/seasonal-assessment/2022/npcc-winter-2022-2023-assessment.pdf

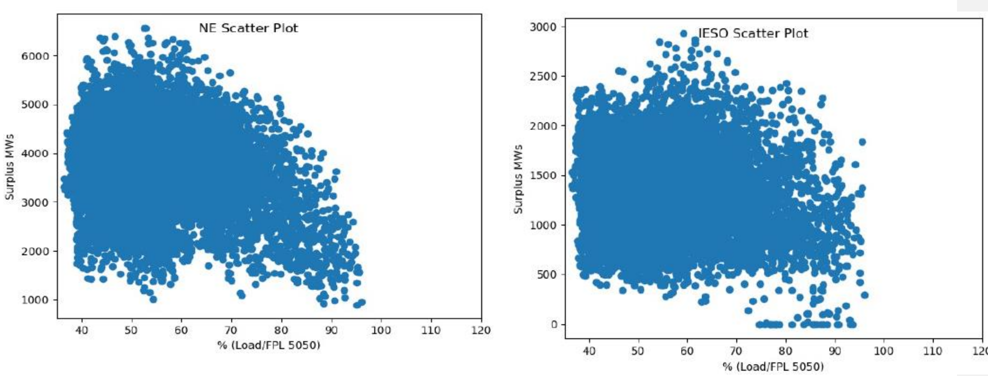
- For PJM, the hourly extra reserves data for the mid-Atlantic region within PJM footprint and calculated the hourly surplus reserves by subtracting the mid-Atlantic region's 30-minute reserve requirements. The 30-minute reserve requirement for mid-Atlantic region is proportional to the PJM total reserves requirement based on the region's share of the system forecasted peak load.
- For HQ, such data is not available. Based on the IRMs study assumption, surplus from HQ is assumed to be 280 MW which is the maximum EA that can be transferred across the interface. In the IRM model, transfer capability between NYCA and HQ has been reduced by the firm transaction amount to 280 MW.

By aligning the hourly extra reserves data with the NYCA hourly load provides the available extra reserves in external areas at corresponding NYCA load levels. Figure 8 shows the scatter plots between extra reserves and % of NYCA 50/50 Forecast Peak Load ("FPL") for the summer season.

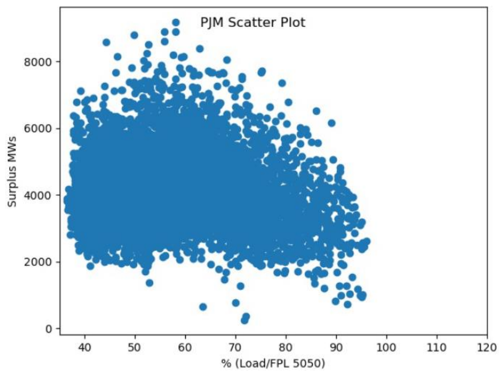
Regression analysis was performed to arrive at Basic X^2 Regression as the best representation of the relationship between NYCA load and available extra reserves in external areas. However, since such analysis is conducted on historical data and NYCA has not seen load beyond ~95% of the 50/50 FPL, extending the regression beyond the available data is needed to develop modeling inputs for conditions beyond 50/50 FPL.

Figure 8 – X^2 Regression results

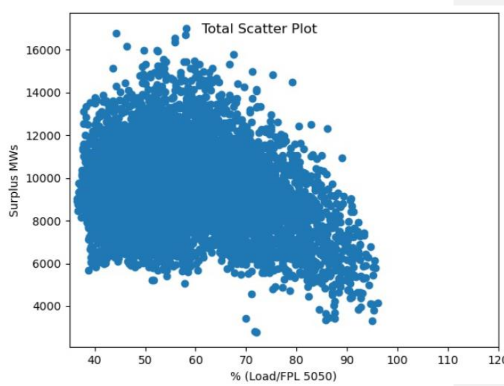
NE Scatter Plot *IESO Scatter Plot*



PJM Scatter Plot



Total Scatter Plot



LFU multipliers from the 2023-2024 IRM study is used to develop NYCA coincident peak load levels for each LFU bins, expressed as a percentage of the NYCA 50/50 FPL.

Table 13 - NYCA coincident peak load levels for each LFU bin

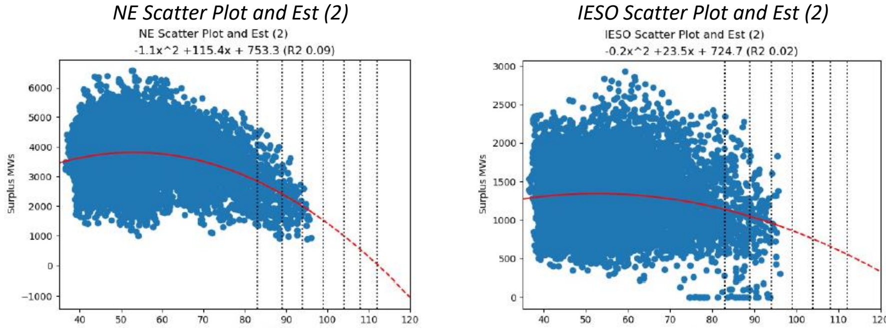
Zone	A	B	C	D	E	F	G	H	I	J	K	NYCA
2024 Coincident Peak (MW)	2701.0	2190.1	2783.3	692.0	1428.0	2412.0	2137.0	620.0	1397.0	11083.0	5008.1	32451.5

Bin	A-E	F&G	H&I	J	K	NYCA Weighted Average LFU Multiplier
Bin 1	113.93%	110.69%	110.18%	108.88%	116.62%	112%
Bin 2	109.54%	107.86%	107.34%	105.42%	111.14%	108%
Bin 3	104.86%	104.04%	103.09%	101.61%	105.52%	104%
Bin 4	100.00%	99.46%	97.81%	97.51%	100.00%	99%
Bin 5	95.00%	94.29%	91.70%	93.12%	94.48%	94%
Bin 6	89.91%	88.61%	84.93%	88.45%	88.89%	89%
Bin 7	84.79%	82.53%	77.65%	83.48%	83.27%	83%

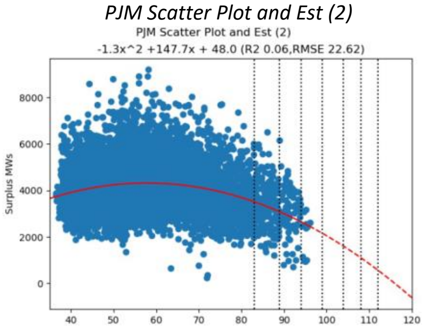
Therefore, combing the load level definition for each LFU bins and the regression relationship between extra reserves and the NYCA load, modeling assumptions for EA limitations can be developed for IESO, ISONE and PJM as well as the total system limits, for the summer season.

Figure 9 – Regression relationship between extra reserves and NYCA load

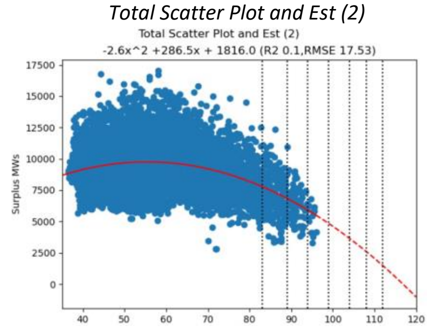
NE Scatter Plot and Est (2) *IESO Scatter Plot and Est (2)*



PJM Scatter Plot and Est (2)

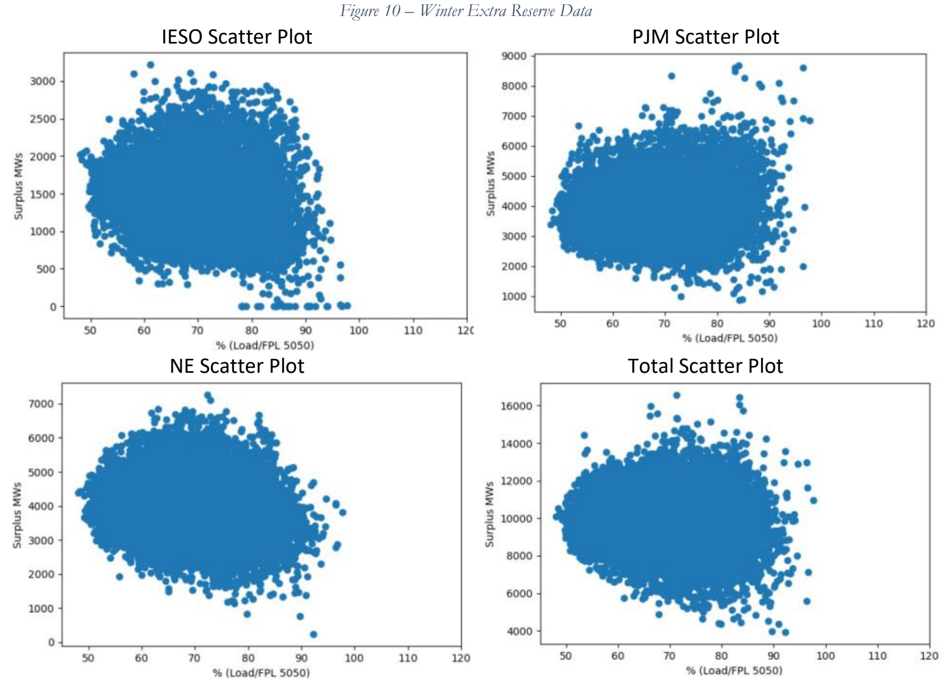


Total Scatter Plot and Est (2)



Same analysis was conducted using the extra reserves data during winter season. However, no meaningful relationship can be extracted between available extra reserves and NYCA load.

Figure 10 – Winter Extra Reserve Data



Processing the NPCC Seasonal Operating Margins Data

Analysis using historical NPCC seasonal operating margins from 2019 to 2023 was also conducted. As the NPCC assessment does not cover PJM, the historical operating margins are available only for Ontario, New England and Quebec.

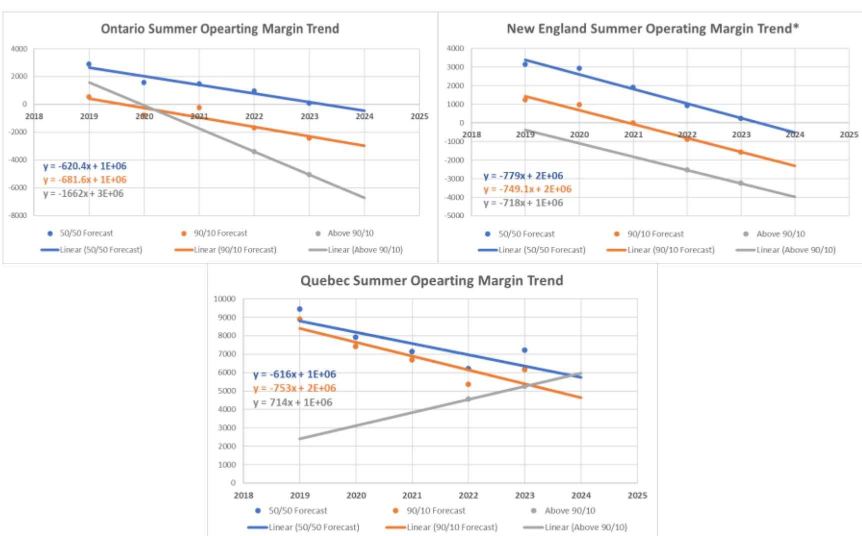
The table below is a summary of the summer operating margins in form of MW available beyond forecast peak load under various conditions. The operating margins for above 90/10 forecast level are only available for year 2022 and 2023. 5- year averages were calculated for each of the regions.

Table 14 – Summary Operating Margins beyond forecasted peak load

Area	Ontario			New England (Capacity Obligations)			Quebec		
Forecast	50/50	90/10	> 90/10	50/50	90/10	> 90/10	50/50	90/10	> 90/10
2019	2887	514		3125	1236		9429	8899	
2020	1558	-803		2920	962		7922	7413	
2021	1468	-250		1900	-1		7125	6675	
2022	952	-1715	-3396	918	-889	-2541	6210	5359	4537
2023	88	-2438	-5058	231	-1584	-3259	7202	6161	5251
5-year Average	1390.6	-938.4	-4227.0	1818.8	-55.2	-2900.0	7577.6	6901.4	4894.0

Based on above data on NPCC summer operating margin, linear trendlines were also applied to all three forecast levels.

Figure 11 – Forecasted level linear trendline



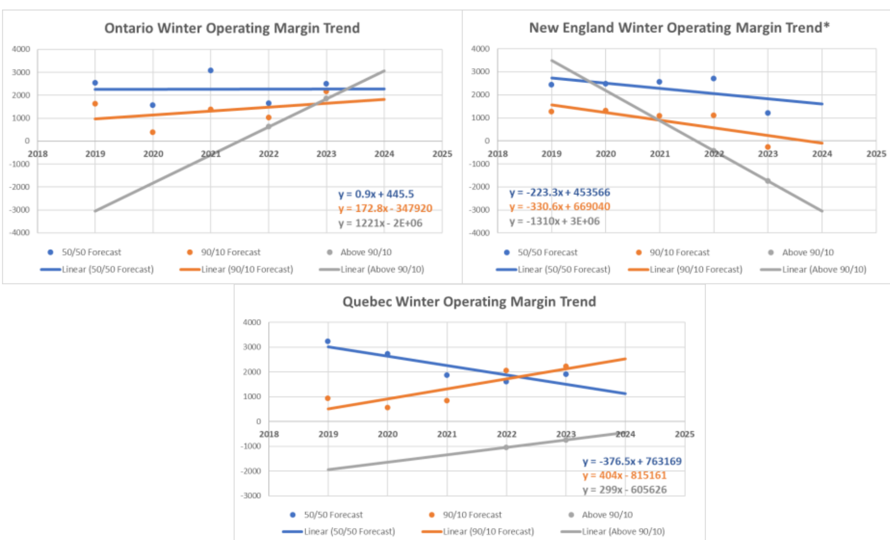
Same analysis was conducted with the winter margin data. The table below is a summary of the past 5-years' winter operating margins. The operating margins for above 90/10 forecast level are only available for year 2021-22 and 2022-23.

Table 15 - Past 5-years' winter operating margins

Area	Ontario			New England (Capacity Obligations)			Quebec		
Forecast	50/50	90/10	> 90/10	50/50	90/10	> 90/10	50/50	90/10	> 90/10
2018-19	2453	1616		2437	1270		3226	940	
2019-20	1559	386		2477	1313		2720	562	
2020-21	3070	1364		2560	1076		1861	844	
2021-22	1646	1012	621	2704	1109	-436	1603	2054	-1048
2022-23	2504	2167	1842	1207	-281	-1746	1902	2214	-749
5-year Average	2264.4	1309	1231.5	2277	897.4	-1091	2262.4	1322.8	-898.5

Based on above data on NPCC winter operating margin, liner trendlines were also applied to all three forecast levels.

Figure 12 – Forecasted levels linear trendlines



The NPCC operating margins do not include assessment for PJM and the historical data analysis yields either extremely conservative or optimistic available margins in the external area – neither provides meaningful assumptions for the IRM model.

Appendix 4 – Impact Assessment – Additional Model Behavior Analysis

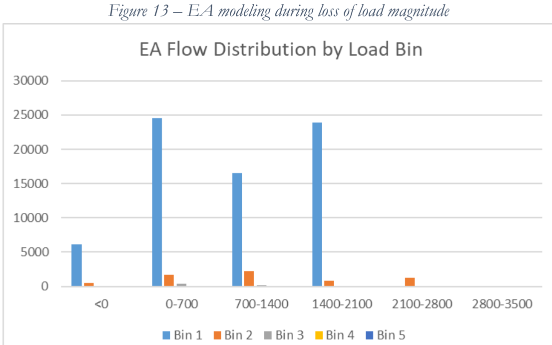
With the implementation of the recommended EA modeling, when NYCA needs external assistance, the assigned maximum EA flow level is reached during Bin 1 (1,470 MW) and 2 (2,600 MW), but do not always require the maximum level of assistance. The maximum EA level is reached 21% of the time in Bin 1, and 12% of the time in Bin 2. During Bin 3 and 4, the maximum observed EA flow is 2,740 MW and 920 MW respectively, and the EA flow does not reach the maximum EA level of 3,500 MW.

During Bin 1, EA flows are dispersed across the flow range, whereas during Bin 2, EA flows are concentrated between 0 MW – 1400 MW. During Bin 3 and 4, EA flows are concentrated between 0 MW to 700 MW. The table below shows the percent distribution of EA during loss of load, and the bar graph shows the magnitude.[17]

Table 15 –EA modeling during loss of load

EA Flow Range	Bin 1 (*1,470 MW*)	Bin 2 (*2,600 MW*)	Bin 3 (*3,500 MW*)	Bin 4 (*3,500 MW*)
@ Max EA Level	21%	12%	0%	0%
2,800 MW – 3,500 MW	0%	0%	0%	0%
2,100 MW – 2,800 MW	0%	20%	2%	0%
1,400 MW – 2,100 MW	34%	12%	5%	0%
700 MW – 1,400 MW	23%	35%	30%	10%
0 MW – 700 MW	35%	26%	63%	90%
< 0 MW	9%	7%	0%	0%

Figure 13 – EA modeling during loss of load magnitude



The composition of EA from which NYCA receives assistance during loss of load events is a critical factor in assessing the effectiveness and impact of external support. On average, NYCA relies on IESO and ISONE the most. In scenarios where the EA flow reaches higher levels, particularly in the top LFU bins, the support from PJM becomes critical. PJM bridges the assistance gap when both IESO and ISONE are

[17] Emergency Assistance during loss of load across 2,750 replications

likely experiencing the similar extreme conditions. NYCA often exports to ISONE during severe and extreme conditions. This is consistent with the historical data from grid operations. The bar graphs below represent the average EA flow composition by LFU bin, at different flow levels.

Figure 14 – Average EA flow by LFU bin

Hourly LOLE distribution was also extracted to assess the impact of the recommended EA modeling to the risk hour window on a given day.

Figure 15 – Hourly LOLE distribution

HB	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
2024 Preliminary Base Case	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	3%	4%	7%	13%	22%	24%	12%	9%	4%	1%	0%	0%
Initial Recommendation (#6a)	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	3%	4%	6%	12%	19%	22%	12%	11%	7%	3%	0%	0%

The hourly LOLE distribution shows the high-risk hours concentrated at HB15 – HB18 for both the Preliminary Base Case and with the implementation of the initial EA recommendation, but the hourly risk distribution is dispersed slight to later in the day with the new EA assumptions.