Generator Maintenance Modelling Whitepaper

Contents

Executive Summary 1
1. Objective 3
2. NYISO Maintenance Scheduling and Approval Process 3
3. Existing IRM Study Modeling of Maintenance Outages and Derates 4
4. Enhanced Maintenance Outage Assessment Methodology 5
5. 2027-2028 IRM Study: Seasonal Maintenance Assessment Results and Recommended Assumptions 6
6. Impact Assessment, Final Recommendations, and Future Enhancements 8
7. Conclusion 8
8. References 9

Executive Summary

As reliability risks tighten across the New York Control Area (NYCA), accurately representing generator availability during peak summer and winter periods remains an important component of the Installed Reserve Margin (IRM) study. Planned maintenance outages are a necessary part of generator operations and can affect the quantity and location of available capacity during periods of high load. Modeling maintenance outages within the IRM study is therefore important to appropriately reflect the operational reliability risks associated with generator maintenance activities. [1] In particular, the tightening winter reliability prompted a review of the existing maintenance modeling approach, including an assessment of whether winter-specific maintenance assumptions should be added to the IRM study model. [2]

Historically, the IRM study represented the reliability impact of planned maintenance outages through a fixed 50 MW peak summer assumption allocated equally between Load Zones J and K (i.e., 25 MW assigned to each Load Zone). [3] To improve the representation of aggregate maintenance impacts during the peak summer (June–August) and winter (December–February) periods, [4]the NYISO reviewed maintenance scheduling and reporting requirements and the treatment of maintenance-related events in the GE Multi-Area Reliability Simulation (MARS) model.

DRAFT

Throughout 2026, the NYISO's maintenance scheduling practices were reviewed, together with the representation of maintenance outage and derating events in Generator Transition Rate Matrix (GTRM) modeling used by the MARS model, in conjunction with the historical outage data for NYCA generators. Based on that review, the recommended summer procedure for implementation beginning with the 2027–2028 IRM study includes two complementary analyses. The first is an annual summer assessment using the most recent rolling five-year period of historical outage data. The assessment identifies outages longer than seven days that occurred on days during the peak summer period (June through August) when system load was at or above 90 percent of the coincident summer peak.[1] Applied to 2021–2025 data, this assessment produced a 65 MW peak summer maintenance outage assumption for the 2027-2028 IRM study: 10 MW in Load Zone A, 15 MW in Load Zone G, 15 MW in Load Zone J, and 25 MW in Load Zone K. The values are rounded to the nearest 5 MW, consistent with existing zonal maintenance assignment practices. [5] The second is the historical "Annual Summer Maintenance Analysis," which uses the most recent single year of outage data and will continue in parallel. This one-year analysis will supplement, rather than be replaced by the proposed new assessment methodology. Continuation of the separate one-year lookback assessment is intended to help monitor recent changes and identify any potential significant differences that may warrant sensitivity cases or adjustments to the maintenance outage assumptions for a given study year.

Because sufficiently representative historical winter outage data is not available at this time, it is recommended that the maintenance outage assumptions developed for the summer of each study year be applied as a transitional winter assumption. The use of the summer-derived assumptions for the winter period would remain in place until sufficient representative winter data becomes available to develop a winter-specific assessment.

A parametric assessment using the 2026–2027 IRM Final Base Case Special Sensitivity Case showed that the updated maintenance outage assumptions developed for the 2027-2028 IRM study had an approximately 0.066 percent increase in the IRM, comparable effects on tan45-dervived locational capacity requirements, an approximately 0.90 percent increase in winter loss of load expectation risk, and a corresponding 0.90 percent decrease in summer loss of load expectation risk. [5]

The use of a broader range of historical outage data during high-load conditions to inform maintenance outage assumptions is designed to improve the representation of maintenance activity in the IRM study. The summer assessment methodology and transitional winter assumptions establish an initial framework that can evolve through future IRM study cycles. The rolling five-year historical data assessment will support periodic updates, while continuance of the "Annual Summer Maintenance Analysis" will provide ongoing monitoring

[1] For purposes of this whitepaper, high-load conditions are days when system load is at or above 90 percent of the coincident summer or winter peak load.

of recent outage activity and emerging trends. As representative winter data become available, a winter assessment methodology can be developed considering the interaction of winter maintenance outage assumptions with other winter reliability modeling assumptions included in the IRM study, such as winter fuel availability constraints.

1. Objective

The objective of this whitepaper is to establish a repeatable methodology for evaluating planned maintenance outages and determining seasonal maintenance outage assumptions for the IRM study. Beginning with the 2027–2028 IRM study, the methodology is intended to improve the representation of maintenance-related reliability risks in the NYCA.

This whitepaper: (1) reviews NYISO practices for scheduling, approving, and managing planned maintenance outages; (2) evaluates how maintenance-related events are represented in MARS through the GTRM; (3) and reviews the methodology developed for annually assessing/updating seasonal maintenance outage assumptions for the IRM study.

This initiative supports the broader efforts to improve how operational reliability risks are represented in the IRM study. The analysis therefore focuses specifically on maintenance outages that occur during near-peak load days, which may affect available generating capacity and contribute to resource adequacy risks.

2. NYISO Maintenance Scheduling and Approval Process

The maintenance modeling initiative began by examining how maintenance outages are scheduled and managed operationally by the NYISO. Maintenance outages are planned through an established approval process intended to balance generator maintenance requirements with the reliability needs of the electric system. Generators submit maintenance outage requests to the NYISO, which are evaluated through capacity margin assessments[2] that compare expected available capacity with forecast system load over the proposed outage period. Long-term maintenance outages are submitted for the next two calendar years and coordinated through reliability assessments of projected weekly operating reserves. Short-term maintenance outage requests are generally submitted at least 30 days before the applicable month in which the proposed maintenance outage occurs but may be approved with as little as two days' advance notice when the NYISO and local Transmission Owner(s) determine that no adverse impacts to reliability are anticipated to occur. [6]

[2] Capacity margins are calculated by subtracting the base load forecast, known maintenance outages, an allowance for unplanned forced outages based on historical average unavailability, and the NYCA 30-minute reserve requirement from total projected seasonal capacity. The NYISO Installed Capacity & Load Maintenance Survey, an annual report issued before each summer, refers to this measure as the 'Maintenance Margin' and presents the forecast level of maintenance for that year.

If in real-time operations the capacity margin assessment identifies reliability concerns, the NYISO may require maintenance outage requests to be modified or rescheduled consistent with applicable outage coordination requirements. The timing and approval of maintenance outages depend on generator maintenance requirements, forecasted system conditions, available reliability margins, and outage duration.

Given the limited potential reliability impacts in the operational timeframe, maintenance activity tends to be concentrated during spring and fall shoulder periods, when system conditions are generally less constrained. Maintenance outages also occur during peak summer and winter periods, although at lower levels because operating margins are tighter and reliability concerns are greater during such periods. The occurrence of maintenance outages during higher load periods makes their potential impact on resource adequacy an important consideration within the IRM study. It is important to note that as reliability margins continue to tighten, the NYISO continues to monitor its maintenance outage scheduling practices to identify any potential need for adjustments. In fact, the NYISO is currently engaged in ongoing discussions with its stakeholders regarding potential refinements to the scheduling of generator maintenance outages during peak summer and winter operating periods.

3. Existing IRM Study Modeling of Maintenance Outages and Derates

Because maintenance activity can occur during high load periods, this initiative also examined how maintenance-related events are represented in MARS. MARS represents generator availability through the GTRM developed from historical outages and derates reported through the Generating Availability Data System (GADS). Planned derates and maintenance derates are incorporated into the GTRM as generator derating states, allowing these event types to affect the probabilistic modeled capacity of the individual resource on which they occurred. [3]

Maintenance outages and planned outages are treated differently from maintenance and planned derates. Unlike derates, maintenance and planned outage event types are not incorporated directly into the GTRM stochastic outage transition process. Their aggregate effect has instead been historically represented in the IRM study through a fixed 50 MW summer maintenance assumption allocated equally between Load Zones J and K. Since 2014, an “Annual Summer Maintenance Analysis” was conducted using hourly system load and GADS outage data from the most recent prior summer, the analysis quantifies maintenance occurring from June 1 through September 15 on days when gross peak load exceeds 28,000 MW. [3]

The proposed method developed as part of this initiative is intended to preserve the existing GTRM methodologies and the treatment of maintenance derating events within MARS while

establishing a repeatable methodology to quantify maintenance outage events not otherwise reflected in the existing availability modeling. Given the emergence of winter risk and the absence of maintenance outage assumptions for the winter period, this effort also included a separate assessment of winter maintenance outage data and modeling options.

4. Enhanced Maintenance Outage Assessment Methodology

The proposed enhancements are designed to facilitate annual reassessment of seasonal maintenance assumptions for the IRM study. An assessment methodology was developed based on a rolling five-years of historical data. As outlined below, the methodology establishes standardized criteria for developing seasonal maintenance assumptions using a rolling five-year dataset and will be refreshed during the Preliminary Base Case (PBC) development for each IRM study. The historical "Annual Summer Maintenance Analysis" remains a useful supplement for monitoring recent summer maintenance activity. Material differences between the rolling five-year assessment and the annual summer analysis based on the most recent prior summer's data will serve as the basis for further consideration of potential sensitivities or adjustments to the maintenance outage assumptions that are more reflective of recent trends. To focus the rolling five-year assessment on maintenance activities most relevant to resource adequacy risk, the methodology evaluates historical outages occurring during periods of high load using four primary criteria.

Table 1: Maintenance Outage Assessment Methodology

Criterion	Methodology	Reason
Historical assessment period	Most recent five years of GADS outage data	Better align with the rolling five-year outage dataset utilized in the GTRM process while reducing sensitivity to individual outage events.
Peak/seasonal periods	Summer (June-August) and Winter (December-February)	Three month seasonal peak operating periods better reflect seasonal risk periods and are also consistent with how maintenance outages are currently modeled in peak summer months
Outage duration	Greater than seven days	The seven day threshold reflects the Day-Ahead Market's seven day forward load forecast, which is used to evaluate capacity margins as part of the NYISO's maintenance scheduling,

		review, and approval processes. Outages extending beyond this forecast period are approved with less certainty regarding system conditions and are therefore considered higher risk for this assessment.
Load condition	Days at or above 90% of coincident seasonal peak load	This threshold limits the assessment to outage activity occurring during conditions where maintenance outages have the greatest potential to affect reliability outcomes

The objective screening criteria above allow for an assessment methodology that is repeatable. Such methodology facilitates annual reassessment of seasonal maintenance assumptions for the IRM study and adjustments thereto as outage patterns and operating conditions evolve. [4]

5. 2027-2028 IRM Study: Seasonal Maintenance Assessment Results and Recommended Assumptions

For the 2027-2028 IRM study, the rolling five-year assessment methodology used data from 2021-2025. This assessment found that maintenance outages occurring during high-load summer conditions were concentrated in a limited number of Load Zones. [5] The highest historical levels were observed in Load Zones A, G, J, and K.

The five-year historical assessment for the 2027-2028 IRM study identified an average of 70.8 MW of summer maintenance outages across the NYCA. [5] Table 2 presents the raw, unrounded results used to develop the final model assumptions for the 2027-2028 IRM study.

Table 2: Historical Average Summer Maintenance Outages by Load Zone

Load Zone	Average Maintenance (MW)
A	11.4
F	2.0
G	16.9
J	13.2
K	27.4
NYCA Total	**70.8**

A separate assessment evaluated whether currently available historical winter maintenance outage data could support development of a winter-specific assumption at this time. The available data was not considered sufficiently representative because winter reliability concerns and tighter capacity margins have emerged more recently. Prior years generally reflect higher winter maintenance outage levels that may not be indicative of future behavior. For example, the introduction of firm fuel elections for capacity accreditation starting with the 2026–2027 Capability Year may change how winter outages are scheduled and managed going forward. The historical dataset identified that approximately 91 percent of the observed winter maintenance outages during peak winter periods were associated with generators that submitted firm fuel elections for the 2026–2027 Capability Year, and those outages were heavily concentrated in Load Zones J and K. Additionally, the NYISO is currently engaged in ongoing discussions with its stakeholders regarding proposed enhancements to winter outage scheduling practices that may further impact future outage behavior. Based on these considerations, it is recommended that the maintenance outage modeling assumption developed for the summer be applied as a transitional interim winter assumption until approximately four winters of representative data become available under the firm fuel framework and any implemented winter outage scheduling enhancements. [5]

The final recommendation involves utilizing the rolling five-year historical assessment and rounding assumed maintenance outage levels to the nearest 5 MW to maintain consistency with existing zonal outage assignment practices. For the 2027-2028 IRM study, this process produced an aggregate NYCA-wide assumed level of maintenance outages equal to 65 MW as shown in Table 3. [5]

Table 3: Recommended Maintenance Outage Assumptions for the 2027-2028 IRM Study

Load Zone	Average Maintenance (MW)
A	10
G	15
J	15
K	25
NYCA Total	**65**

Beginning with the 2027-2028 IRM study, it is recommended that the 65 MW zonal allocation shown in Table 3 be modeled during both the peak summer period (June-August) and the peak winter period (December-February), regardless of modeled load conditions. [5] The maintenance assumptions will be reevaluated annually based on the updated rolling five-year assessment and adjusted as appropriate.

6. Impact Assessment, Final Recommendations, and Future Enhancements

A parametric assessment was conducted using the 2026-2027 IRM Final Base Case Special Sensitivity Case to evaluate the potential impact of the recommended maintenance methodology. Implementation of the recommended assumptions for the 2027-2028 IRM study resulted in an approximate increase of 0.066 percent in the IRM, comparable impacts on the tan45-derived locational capacity requirements, and an increase of approximately 0.90 percent in winter loss of load expectation risk. [5]

Table 4: Impact on the IRM

Case	IRM (%)	J LCR (%)	K LCR (%)	G-J LCR (%)	Winter Risk (%)	Summer Risk (%)
2026-2027 FBC (Special Sensitivity)	25.60	79.85	107.50	89.22	14.80	85.20
Recommended Maintenance Modeling	25.66	79.90	107.56	89.27	15.7	84.3
Delta	+ 0.066%	+ 0.05%	+ 0.06%	+ 0.02%	+ 0.9%	-0.9%

The analysis demonstrates that maintenance outage assumptions can affect both the overall IRM and the seasonal distribution of reliability risk within the IRM study. Incorporating seasonal maintenance assumptions based on historical outage behavior therefore provides a more structured approach for representing maintenance-related reliability risks.

7. Conclusion

Based on the research and analysis conducted, it is recommended that the proposed maintenance outage modeling methodology be implemented beginning with the 2027-2028 IRM study. The methodology provides a repeatable process for determining seasonal maintenance assumptions using observed outage behavior during periods of high load while maintaining consistency with existing IRM study practices.

Additionally, it is recommended that the "Annual Summer Maintenance Analysis" be continued in parallel with the rolling five-year approach to monitor recent year-to-year changes in maintenance outage trends. Although the annual analysis may exhibit greater volatility

because it relies on only a single year of historical data, it can identify granular changes that may be less apparent in the five-year dataset. Both results will be reviewed during the IRM study cycle, and sensitivity cases or adjustments to the maintenance modeling assumptions for a given study cycle may be considered when significant differences arise between the two methodologies.

Overall, the maintenance outage methodology is intended to establish an initial framework that can continue to evolve through future study cycles. Maintenance assumptions should continue to be updated using the rolling five-year historical assessment, while annual maintenance reviews continue to monitor recent outage activity and identify emerging trends. [5] As additional representative winter outage data becomes available, future enhancements may be considered to further refine winter maintenance assumptions and evaluate interactions with other winter reliability modeling constructs in the IRM study such as winter fuel availability constraints.

8. References

[1] NYSRC ICS, "NYISO Outage Scheduling Process: Maintenance Modeling - Output Factor," ICS Meeting #314, 4 March 2026. [Online]. Available: https://www.nysrc.org/wp-content/uploads/2026/02/Maintenance-Modeling-Output-Factor-03042026-ICS.pdf.

[2] NYSRC ICS, "NYISO Resource Adequacy Modelling Improvements Strategic Plan (2026-2030)," ICS Meeting #308, 1 October 2025. [Online]. Available: https://www.nysrc.org/wp-content/uploads/2025/09/RA-Modeling-Improvement-2026-Strategic-Plan-10012025-ICS.pdf.

[3] NYSRC ICS, "Maintenance Modeling & Output Factor Curves - IRM/MARS fundamentals: Maintenance modeling - Output Factor," ICS Meeting #315, 31 March 2026. [Online]. Available: https://www.nysrc.org/wp-content/uploads/2026/03/Maintenance-Modeling-Output-Factor-ICS-3-31-2026.pdf.

[4] NYSRC ICS, "Maintenance Modeling & Output Factor Curves - Modeling Seasonal Maintenance: Maintenance Modeling - Output Factor," ICS Meeting #317, 3 June 2026. [Online]. Available: https://www.nysrc.org/wp-content/uploads/2026/06/Maintenance-Modeling-Output-Factor-ICS-317-Uploaded.pdf.

[5] NYSRC ICS, "Maintenance Modeling Whitepaper - Final Recommendations: Maintenance Modeling - Output Factor," ICS Meeting #318, 8 July 2026. [Online]. Available: https://www.nysrc.org/wp-content/uploads/2026/07/Maintenance-Modeling-Output-Factor-07082026-ICS.pdf.

[6] NYISO, "Manual 29 - Outage Scheduling Manual," May 2026. [Online].