# Enhanced Load Modeling Whitepaper – BTM Solar Modeling Phase 2

## Executive Summary

The estimated impact of behind-the-meter (BTM) solar energy reduction is currently embedded in the load shape used in the installed reserve margin (IRM) study. The absence of explicit modeling may not adequately capture the impact and risk of BTM solar as compared to other similar, intermittent supply resources. In addition, with the expectation of increasing BTM solar penetration over time, monitoring and quantifying the impact of BTM solar resources in the IRM study is of increasing importance. By modeling BTM solar explicitly as a supply resource, the impact of BTM solar would be accounted for consistent with similar intermittent supply resources. Such explicit modeling would also facilitate direct measuring of the impact of BTM solar on the New York Control Area (NYCA) system.

As part of the 5-year modeling improvement plan for 2024, the New York State Reliability Council (NYSRC) Installed Capacity Subcommittee (ICS) developed a methodology to model BTM solar explicitly as a supply resource in the IRM model.[1] The BTM solar modeling enhancements involve both load-side and supply-side modeling adjustments. The NYSRC, however, also identified limitations with the current load shape adjustment procedure that could adversely impact implementation of the BTM solar modeling enhancements.[2] For example, the lack of annual energy representation in the load shape adjustment process is particularly problematic with modeling BTM solar explicitly as a supply resource because the available BTM solar hourly production data is normalized based on the forecasted annual energy level. The current load shape adjustment procedure also lacks the winter demand modeling, which may result in inaccurate representation of BTM solar impact during the winter periods. Without complementary improvements to the current load side modeling, this issue will be exacerbated when accompanied by an explicit modeling of BTM solar as a supply resource. After thorough review, the ICS recommended improvement of the load shape adjustment procedure and implementing such improvements together with the BTM solar modeling changes.

As part of the updated modeling improvement strategic plan for 2025, development of enhanced load modeling (ELM) was added as part of the efforts to improve winter load modeling. The load modeling improvement effort addressed herein focuses on seasonal specific load modeling to reflect summer and winter peak forecasts as well as annual energy requirements. The proposed ELM workflow includes three additional steps, along with the updates to the existing adjustment methodology procedures to ensure that the seasonal peaks align with the target load forecasts, as well as the corresponding annual energy forecasts.

## 1. Background

### 1.1. 2024 BTM Solar Modeling Effort

[1] BTM Solar Modeling Whitepaper – NYSRC: https://www.nysrc.org/wp-content/uploads/2025/01/BTM-Solar-Modeling-Whitepaper-11122024.pdf
[2] Current IRM Load Shape Adjustment Procedure – 02.27.2024 ICS: https://www.nysrc.org/wp-content/uploads/2024/02/IRM-Load-Shape-Adjustment-Procedure-02272024-ICS28518.pdf

As part of the 5-year modeling improvement strategic plan for 2024, the ICS developed a methodology to model BTM solar explicitly as a supply resource in the IRM model. Modeling BTM solar explicitly as a supply resource involves both load-side and supply-side modeling adjustments. This is due to the current IRM load modeling construct where the impact of BTM solar is embedded within the underlying load shapes resulting in the conduct of the IRM study on a net-of-BTM-solar basis (i.e., load shapes and peak forecasts are net of estimated BTM solar production). Thus, the impact of BTM solar needs to be "added back" to the load shapes to provide load modeling on a gross basis. The BTM solar modeling enhancements reflect BTM solar as a supply resource using negative Demand Side Management (DSM) profiles for the load-side modeling in conjunction with 5-year historical BTM solar production profiles for the supply-side modeling. This supply-side modeling is consistent with the other intermittent resources, such as in-front-of-the-meter (FTM) solar. An impact assessment conducted with Tan45 methodology demonstrated a 1.05% increase to the IRM from the approved 2025-2026 IRM Preliminary Base Case (PBC), as well as increases to the Tan45-determined locational capacity requirements (LCRs). An updated impact assessment using the 2025-2026 IRM Final Base Case (FBC) is presented herein.

### 1.1.1. Load-side modeling

The load-side modeling entails adding the estimated BTM solar penetration back to the underlying load shapes used in the study, resulting in effectively modeling the expected gross load.

To avoid the issues related to the existing load shape adjustment method, utilizing negative DSM shapes is recommended to represent the load-side modeling of BTM solar. 2013, 2017, and 2018 BTM solar zonal hourly load profiles are programmed to be aligned with the underlying load shapes.

| | LFU Bins 1 – 2 | LFU Bins 3 – 4 | LFU Bins 5 – 7 |
|---|---|---|---|
| **Representative Historical Weather Year** | 2013 | 2018 | 2017 |

The negative hourly DSM shapes effectively mimic the effect of hourly load shapes independent of the underlying load shape adjustment process. The use of DSM shapes also avoids application of the Load Forecast Uncertainty (LFU) multipliers to the BTM solar production.

### 1.1.2. Supply-side modeling

The supply-side modeling of BTM solar is consistent with current modeling approach for intermittent resources within the IRM study, which involves random selection from 5 years of historical productions profiles.

Due to the nature of BTM solar resources, explicit historical production data is not available. Therefore, the NYISO's estimated BTM solar hourly production data was utilized. Specifically, hourly estimated production profiles for 2019–2023 were used in the impact assessment for the BTM solar modeling enhancements. Modeling random selection of these BTM solar profiles is consistent with other intermittent resources to ensure weather-year consistency during GE Multi-Area Reliability Simulation software program (MARS) simulations.

### 1.2. Current IRM Load Shape Adjustment Process and Limitations

The current load shape adjustment procedure used in the IRM study includes non-coincident peak (NCP), coincident peak (CP), and G–J Locality peak adjustments. In the current IRM study, BTM solar adjusted 2013, 2017, and 2018 historical load shapes, as determined based on the "LFU Phase 2 study,"[3] are adjusted to reflect the forecasted summer peak demand for the Capability Year covered by each IRM study. Once the NYCA load shapes are adjusted the external load shapes are adjusted to ensure that the external control areas have the same top three peak load days as the NYCA. The current procedure does not include any annual energy forecast adjustment. However, due to the nature of the non-coincident peak scaling method, the historical load shapes with less prominent peak loads, particularly the 2017 and 2018 load shapes, would result in overinflated annual energy levels. The lack of annual energy representation in the load shape adjustment process is particularly problematic with modeling BTM solar explicitly as a supply resource because the available BTM solar hourly production data is normalized based on the forecasted annual energy level. The current load shape adjustment procedure also lacks modeling winter demand, which may result in inaccurate representation of the impact of BTM solar during the winter periods. Although these concerns exist today, they would be exacerbated by the BTM solar modeling enhancements. The ICS, therefore, recommended improvement of the load shape adjustment procedure and implementing such improvements together with the BTM solar modeling changes.

### 1.3. 2025 Enhanced Load Modeling Effort

Continuing the 2024 efforts to model BTM solar resource explicitly as a supply resource in the IRM model, the updated modeling improvement strategic plan for 2025 includes load modeling improvement efforts which seek to address the following:

- Production of load shapes aligned with seasonal (summer/winter) peak forecasts
- Production of load shapes aligned with annual energy forecasts

This whitepaper addresses the proposed ELM methodology, as well as the potential impact of the BTM solar and ELM improvements on the IRM.

## 2. ELM Assumptions

### 2.1. Summer Peak Forecast:

Consistent with the summer peak forecast assumptions used in the 2025-2026 IRM FBC, the NYISO used the "NYSRC Fall Forecast" values[4] and the zonal Behind-the-Meter Net Generation

[3] Load Forecast Uncertainty (LFU) Phase 2 Study – Updated Load Shape Recommendation: https://www.nyiso.com/documents/20142/29418084/07%20LFU%20Phase%202_Recommendation.pdf

[4] NYSRC Fall Forecast Update (2025 Final IRM Forecast) – 10.04.2024 ICS: https://www.nysrc.org/wp-content/uploads/2024/10/01-NYSRC-Fall-Forecast-Update-2025-Final-Installed-Reserve-Margin-Forecast.pdf

Resource (BTM:NG) peak proxy load for the summer peak forecast in assessing the proposed ELM methodology.

**2025 IRM Zonal Peak Forecasts With BTM:NG Adjustments**

| BTM:NG Adjustments to Load | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| A | B | C | D | E | F | G | H | I | J | K | NYCA |
| 0.5 | 50.5 | 62.6 | | 1.3 | | | | | 18.3 | 37.4 | 170.6 |

| Zonal Coincident Peak Forecast With BTM:NG Adjustments | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| A | B | C | D | E | F | G | H | I | J | K | NYCA |
| 2,926.8 | 1,925.4 | 2,596.5 | 693.0 | 1,291.2 | 2,239.2 | 2,235.5 | 600.7 | 1,323.1 | 10,802.3 | 5,016.0 | 31,649.7 |

| Zonal Non-Coincident Peak Forecasts With BTM:NG Adjustments | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| A | B | C | D | E | F | G | H | I | J | K |
| 3,089.2 | 1,971.1 | 2,675.8 | 721.3 | 1,326.2 | 2,293.8 | 2,286.2 | 614.2 | 1,352.7 | 11,043.9 | 5,092.1 |

| G-to-J Locality Peak Forecast With BTM:NG Adjustments | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| A | B | C | D | E | F | G | H | I | J | K | G-to-J |
| | | | | | | 2,271.8 | 610.5 | 1,344.7 | 10,978.1 | | 15,205.1 |

*Note: Forecast values include large loads.*

## 2.2. Winter Peak Forecast:

The NYISO used the 2024 Load & Capacity Data report (Gold Book) "Baseline Forecast"[5] (Gold Book Tables I-3b, I-4b, and I-5) for the 2025-2026 winter forecast values underlying this assessment. The zonal BTM:NG peak proxy load values for summer are added on top of the Gold Book winter forecast values presented below.

**Table I-4b: Baseline Winter Non-Coincident Peak Demand, Historical & Forecast**

*Includes Impacts of Energy Saving Programs, Behind-the-Meter Generation, Electrification, & Large Loads*

**Non-Coincident Winter Peak Demand by Zone - MW**

| Year | A | B | C | D | E | F | G | H | I | J | K |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2014-15 | 2,419 | 1,617 | 2,689 | 725 | 1,339 | 1,925 | 1,556 | 537 | 954 | 7,481 | 3,406 |
| 2015-16 | 2,253 | 1,486 | 2,469 | 667 | 1,307 | 1,861 | 1,496 | 453 | 889 | 7,274 | 3,164 |
| 2016-17 | 2,295 | 1,600 | 2,573 | 671 | 1,395 | 1,867 | 1,549 | 530 | 917 | 7,482 | 3,285 |
| 2017-18 | 2,313 | 1,533 | 2,766 | 735 | 1,398 | 2,012 | 1,638 | 506 | 933 | 7,822 | 3,425 |
| 2018-19 | 2,107 | 1,566 | 2,668 | 747 | 1,416 | 2,066 | 1,618 | 534 | 941 | 7,674 | 3,390 |
| 2019-20 | 2,100 | 1,460 | 2,482 | 741 | 1,305 | 1,854 | 1,468 | 479 | 842 | 7,398 | 3,124 |
| 2020-21 | 2,095 | 1,505 | 2,418 | 750 | 1,251 | 1,856 | 1,481 | 485 | 869 | 6,689 | 3,143 |
| 2021-22 | 2,120 | 1,507 | 2,512 | 846 | 1,283 | 1,894 | 1,506 | 491 | 861 | 7,116 | 3,101 |
| 2022-23 | 2,087 | 1,566 | 2,637 | 835 | 1,344 | 1,927 | 1,580 | 522 | 872 | 7,070 | 3,123 |
| 2023-24 | 2,154 | 1,464 | 2,378 | 827 | 1,294 | 1,826 | 1,528 | 494 | 855 | 7,200 | 3,043 |
| 2024-25 | 2,220 | 1,526 | 2,518 | 878 | 1,306 | 1,935 | 1,517 | 519 | 886 | 7,420 | 3,284 |
| 2025-26 | 2,308 | 1,597 | 2,486 | 1,043 | 1,315 | 1,934 | 1,535 | 519 | 895 | 7,480 | 3,312 |
| 2026-27 | 2,374 | 1,639 | 2,592 | 1,194 | 1,312 | 1,943 | 1,559 | 523 | 906 | 7,560 | 3,347 |
| 2027-28 | 2,428 | 1,660 | 2,680 | 1,284 | 1,327 | 2,013 | 1,602 | 533 | 924 | 7,630 | 3,410 |

5 2024 Load & Capacity Data Report – NYISO: https://www.nyiso.com/documents/20142/2226333/2024-Gold-Book-Public.pdf

**Table I-3b: Baseline Winter Coincident Peak Demand, Historical & Forecast**

*Includes Impacts of Energy Saving Programs, Behind-the-Meter Generation, Electrification, & Large Loads*

**Coincident Winter Peak Demand by Zone - MW**

| Year | A | B | C | D | E | F | G | H | I | J | K | NYCA |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2014-15 | 2,419 | 1,617 | 2,689 | 725 | 1,339 | 1,925 | 1,556 | 537 | 954 | 7,481 | 3,406 | 24,648 |
| 2015-16 | 2,253 | 1,486 | 2,469 | 667 | 1,307 | 1,861 | 1,496 | 453 | 889 | 7,274 | 3,164 | 23,319 |
| 2016-17 | 2,295 | 1,600 | 2,573 | 671 | 1,395 | 1,867 | 1,549 | 530 | 917 | 7,482 | 3,285 | 24,164 |
| 2017-18 | 2,313 | 1,533 | 2,766 | 735 | 1,398 | 2,012 | 1,638 | 506 | 933 | 7,822 | 3,425 | 25,081 |
| 2018-19 | 2,107 | 1,566 | 2,668 | 747 | 1,416 | 2,066 | 1,618 | 534 | 941 | 7,674 | 3,390 | 24,727 |
| 2019-20 | 2,100 | 1,460 | 2,482 | 741 | 1,305 | 1,854 | 1,468 | 479 | 842 | 7,398 | 3,124 | 23,253 |
| 2020-21 | 2,095 | 1,505 | 2,418 | 750 | 1,251 | 1,856 | 1,481 | 485 | 869 | 6,689 | 3,143 | 22,542 |
| 2021-22 | 2,120 | 1,507 | 2,512 | 846 | 1,283 | 1,894 | 1,506 | 491 | 861 | 7,116 | 3,101 | 23,237 |
| 2022-23 | 2,087 | 1,566 | 2,637 | 721 | 1,344 | 1,927 | 1,580 | 487 | 872 | 7,070 | 3,078 | 23,369 |
| 2023-24 | 1,988 | 1,458 | 2,364 | 822 | 1,294 | 1,779 | 1,528 | 494 | 853 | 7,131 | 3,043 | 22,754 |
| 2024-25 | 2,196 | 1,514 | 2,513 | 860 | 1,283 | 1,923 | 1,506 | 508 | 876 | 7,350 | 3,271 | 23,800 |
| 2025-26 | 2,283 | 1,584 | 2,481 | 1,022 | 1,292 | 1,922 | 1,524 | 508 | 885 | 7,410 | 3,299 | 24,210 |
| 2026-27 | 2,348 | 1,626 | 2,587 | 1,169 | 1,289 | 1,931 | 1,548 | 512 | 896 | 7,490 | 3,334 | 24,730 |
| 2027-28 | 2,402 | 1,647 | 2,675 | 1,258 | 1,304 | 2,001 | 1,591 | 522 | 914 | 7,560 | 3,396 | 25,270 |

**Table I-5: Baseline Peak Demand in G-to-J Locality, Historical & Forecast**

*Includes Impacts of Energy Saving Programs, Behind-the-Meter Generation, Electrification, & Large Loads*

**G-to-J Locality Summer Peak Demand by Zone - MW**

| Year | G | H | I | J | G-J |
|---|---|---|---|---|---|
| 2014 | 2,046 | 585 | 1,348 | 10,572 | 14,551 |
| 2015 | 2,168 | 629 | 1,398 | 10,583 | 14,778 |
| 2016 | 2,123 | 636 | 1,392 | 10,990 | 15,141 |
| 2017 | 2,125 | 611 | 1,367 | 10,671 | 14,774 |
| 2018 | 2,130 | 642 | 1,379 | 10,979 | 15,130 |
| 2019 | 1,992 | 582 | 1,336 | 10,767 | 14,677 |
| 2020 | 1,992 | 648 | 1,368 | 10,139 | 14,147 |
| 2021 | 2,197 | 673 | 1,407 | 10,352 | 14,629 |
| 2022 | 2,133 | 671 | 1,385 | 10,779 | 14,968 |
| 2023 | 2,017 | 664 | 1,239 | 10,357 | 14,277 |
| 2024 | 2,177 | 619 | 1,347 | 11,077 | 15,220 |
| 2025 | 2,188 | 624 | 1,353 | 11,116 | 15,281 |
| 2026 | 2,198 | 629 | 1,360 | 11,146 | 15,333 |
| 2027 | 2,214 | 634 | 1,370 | 11,176 | 15,394 |

**G-to-J Locality Winter Peak Demand by Zone - MW**

| Year | G | H | I | J | G-J |
|---|---|---|---|---|---|
| 2014-15 | 1,500 | 515 | 941 | 7,632 | 10,588 |
| 2015-16 | 1,524 | 442 | 896 | 7,297 | 10,159 |
| 2016-17 | 1,549 | 530 | 917 | 7,483 | 10,479 |
| 2017-18 | 1,638 | 506 | 933 | 7,822 | 10,899 |
| 2018-19 | 1,593 | 521 | 941 | 7,727 | 10,782 |
| 2019-20 | 1,468 | 479 | 842 | 7,398 | 10,187 |
| 2020-21 | 1,465 | 533 | 841 | 6,829 | 9,668 |
| 2021-22 | 1,506 | 491 | 861 | 7,116 | 9,974 |
| 2022-23 | 1,580 | 487 | 872 | 7,070 | 10,009 |
| 2023-24 | 1,515 | 483 | 846 | 7,200 | 10,044 |
| 2024-25 | 1,503 | 506 | 876 | 7,394 | 10,279 |
| 2025-26 | 1,521 | 506 | 885 | 7,454 | 10,366 |
| 2026-27 | 1,545 | 510 | 896 | 7,535 | 10,486 |
| 2027-28 | 1,588 | 520 | 914 | 7,605 | 10,627 |

## 2.3. Annual Energy Forecast:

In conducting the assessment of the proposed ELM methodology, the NYISO used the 2024 Gold Book "baseline zonal annual energy forecast" (Gold Book Table I-2) as the basis for the 2025 annual energy requirement. The zonal BTM:NG peak proxy load values × 8,760 are added on top of the Gold Book annual energy forecast values presented below.

**Table I-2: Baseline Annual Energy, Historical & Forecast**

*Includes Impacts of Energy Saving Programs, Behind-the-Meter Generation, Electrification, & Large Loads*

**Annual Energy by Zone - GWh**

| Year | A | B | C | D | E | F | G | H | I | J | K | NYCA |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2014 | 15,885 | 9,899 | 16,345 | 4,835 | 8,155 | 12,008 | 9,832 | 2,694 | 6,281 | 52,529 | 21,563 | 160,026 |
| 2015 | 15,761 | 9,906 | 16,299 | 4,441 | 8,141 | 12,422 | 10,065 | 2,847 | 6,299 | 53,485 | 21,906 | 161,572 |
| 2016 | 15,803 | 9,995 | 16,205 | 4,389 | 7,894 | 12,298 | 9,975 | 2,856 | 6,139 | 53,653 | 21,591 | 160,798 |
| 2017 | 15,261 | 9,775 | 15,819 | 4,322 | 7,761 | 11,823 | 9,669 | 2,883 | 5,976 | 52,266 | 20,815 | 156,370 |
| 2018 | 15,894 | 10,090 | 16,561 | 4,670 | 7,995 | 12,375 | 9,965 | 2,807 | 6,071 | 53,360 | 21,326 | 161,114 |
| 2019 | 14,872 | 9,715 | 15,809 | 4,825 | 7,868 | 11,829 | 9,574 | 2,816 | 5,976 | 52,003 | 20,545 | 155,832 |
| 2020 | 14,514 | 9,698 | 15,450 | 5,047 | 7,626 | 11,827 | 9,217 | 2,849 | 5,729 | 48,060 | 20,181 | 150,198 |
| 2021 | 14,731 | 9,797 | 15,560 | 5,415 | 7,616 | 11,827 | 9,262 | 2,884 | 5,781 | 48,832 | 20,273 | 151,978 |
| 2022 | 14,687 | 9,616 | 15,365 | 5,884 | 7,357 | 11,935 | 9,325 | 2,902 | 5,775 | 49,740 | 20,095 | 152,681 |
| 2023 | 14,613 | 9,135 | 14,693 | 5,698 | 7,038 | 11,096 | 9,014 | 2,686 | 5,412 | 48,280 | 19,385 | 147,050 |
| 2024 | 15,490 | 9,300 | 14,950 | 5,770 | 7,190 | 11,300 | 9,220 | 2,760 | 5,500 | 49,260 | 19,800 | 150,540 |
| 2025 | 15,960 | 10,000 | 14,590 | 5,850 | 7,010 | 11,030 | 9,230 | 2,740 | 5,530 | 49,210 | 19,870 | 151,020 |
| 2026 | 16,100 | 10,330 | 14,810 | 7,380 | 6,740 | 10,780 | 9,280 | 2,740 | 5,560 | 49,290 | 19,980 | 152,990 |
| 2027 | 15,950 | 10,310 | 14,890 | 8,640 | 6,530 | 10,730 | 9,380 | 2,760 | 5,610 | 49,560 | 20,170 | 154,530 |

*Tables 1 and 2* below show the winter peak demand and annual energy requirements modeled in the 2025-2026 IRM FBC compared to the target winter forecasts and annual energy requirements modeled with the proposed ELM.

*Table 1 - Modeled Winter Peak Demand (MW)*

| | 2025-2026 IRM | | | ELM | | |
|---|---|---|---|---|---|---|
| **Max of…** | Y2013 | Y2017 | Y2018 | Y2013 | Y2017 | Y2018 |
| **Zone A** | 2,797.0 | 3,011.6 | 2,699.9 | 2,308.5 | | |
| **Zone B** | 1,654.0 | 1,857.9 | 1,492.8 | 1,647.5 | | |
| **Zone C** | 2,566.8 | 2,838.3 | 2,513.7 | 2,548.6 | | |
| **Zone D** | 856.2 | 979.9 | 868.5 | 1,043 | | |
| **Zone E** | 1,274.8 | 1,450.8 | 1,426.1 | 1,316.3 | | |
| **Zone F** | 1,981.8 | 2,214.3 | 1,934.5 | 1934 | | |
| **Zone G** | 1,680.6 | 1,889.8 | 1,757.1 | 1535 | | |
| **Zone H** | 471.2 | 578.4 | 545.7 | 519 | | |
| **Zone I** | 887.4 | 964.8 | 930.3 | 895 | | |
| **Zone J** | 7,259.0 | 7,973.4 | 7,901.5 | 7,498.3 | | |
| **Zone K** | 3,192.4 | 3,550.0 | 3,345.9 | 3,349.4 | | |
| **NYCA** | 24,297.3 | 27,016.7 | 25,296.0 | 24,380.6 | | |
| **G – J Locality** | 10,187.1 | 11,261.7 | 11,082.9 | 10,384.3 | | |

*Table 2 - Modeled Energy (TWh)*

| 2025-2026 IRM | | | ELM | | |
|---|---|---|---|---|---|
| Y2013 | Y2017 | Y2018 | Y2013 | Y2017 | Y2018 |
| 154.1 | 167.2 | 157.0 | 152.5 | | |

## 3. <u>Proposed ELM Overview</u>

The 2025-2026 IRM FBC overstated the winter load levels due to the existing load adjustment procedure. The overrepresentation of winter load was especially prominent in the lower LFU bins. This is because the lower LFU bins represent a flatter load profile with lower peak load. Using the current NCP adjustment procedure that increases load all hours by the NCP ratio exacerbates the overstatement of load values during non-peak hours, leading to higher load in winter period.

*Figures 1 – 3* below show the NYCA load profiles of the modeled winter CP day (24-hour period). The proposed ELM effectively models the winter peaks to match the target load forecast. With the proposed ELM, the variability of different weather scenarios will be more predictable and be dependent on the existing LFU multipliers in the model.

*Figure 1- Y2013 winter CP day (LFU bins 1 - 2)*

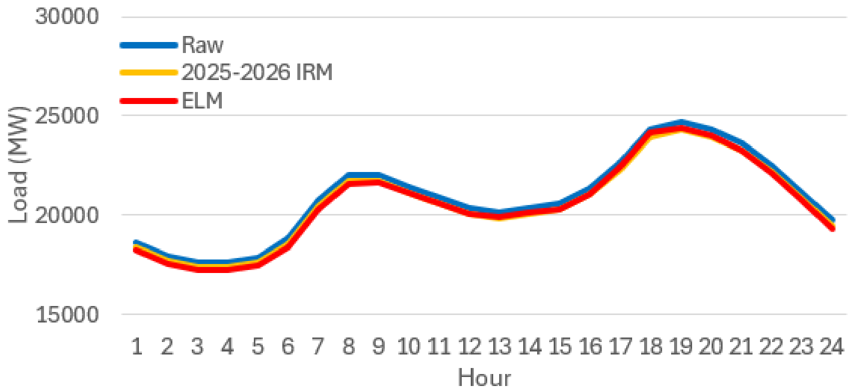



*Figure 2 - Y2018 winter CP day (LFU bins 3 - 4)*

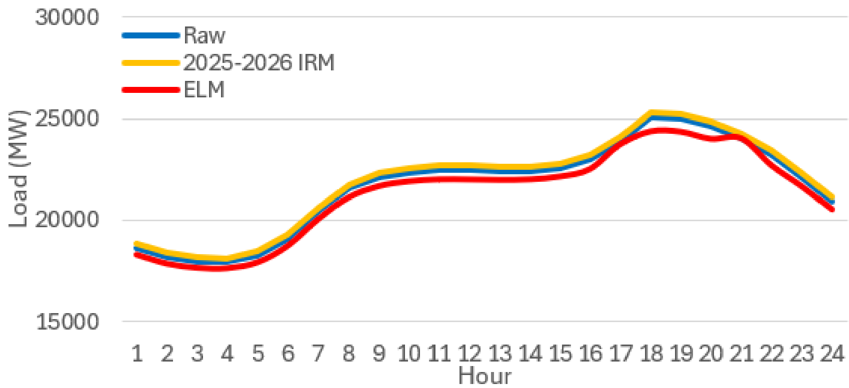
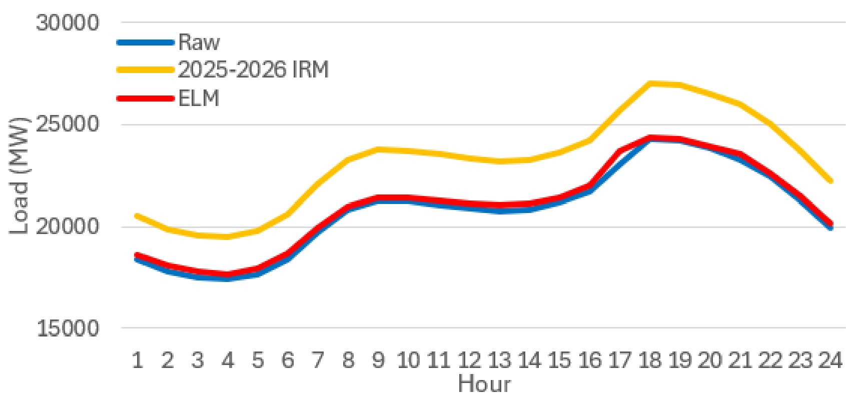



*Figure 3 - Y2017 winter CP day (LFU bins 5-7)*




Based on the per-unit load (relative to annual peak) duration curve comparison analysis of top 100 hours, the 2013 load shapes in *Figure 4* show negligible differences in the load profiles between the raw shape, the load shape used in 2025-2026 IRM FBC, and the load shape created using the proposed ELM.

The differences in the load profiles between the 2025-2026 IRM FBC shape and the load shape created using the proposed ELM observed for the 2018 shapes in *Figure 5* is due to the reduction in modeled energy using the proposed ELM. However, the proposed ELM retains the “peakier” load profiles (with a more prominent peak) of the 2013 load shape compared to the 2018 shape, as intended based on the “LFU Phase 2 study.”

*Figure 4 - Y2013 Load Duration Curve*

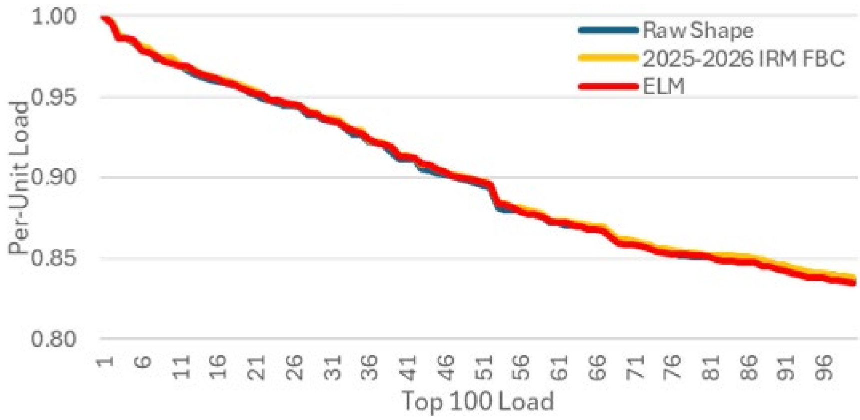
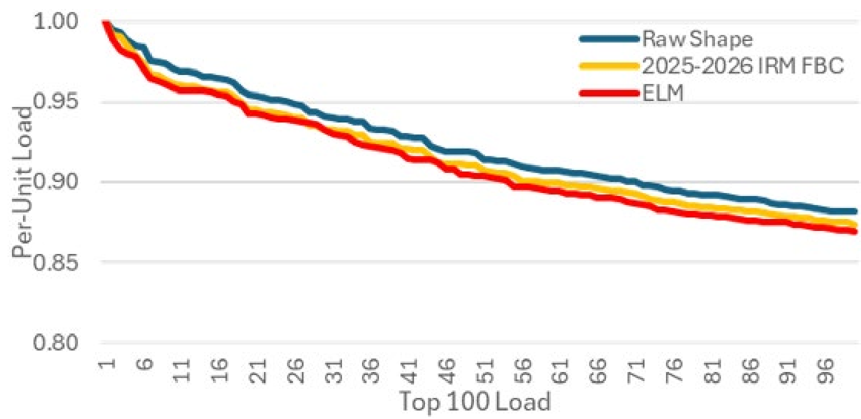



*Figure 5 - Y2018 Load Duration Curve*




## 4. <u>Proposed ELM Methodology</u>

### 4.1. NYCA Load Shape Adjustment Overview

The current IRM load shape adjustment process workflow consists of the following:

NCP adjustment → CP adjustment → G–J Locality peak adjustment

The proposed ELM workflow includes an additional step before the overall process, as well as modifications to the existing steps as follows:

*Energy Adjustment* → NCP adjustment → CP adjustment → G–J Locality peak adjustment

Additional NCP correction and energy recalibration may be needed to correct any misalignments.

### 4.2. Energy Adjustment

The zonal energy adjustment ratio $r_{Zone}$, is calculated as follows:

$$r_{Zone} = \frac{Target\ Energy_{Zone}}{Historical\ Energy_{Zone}}$$

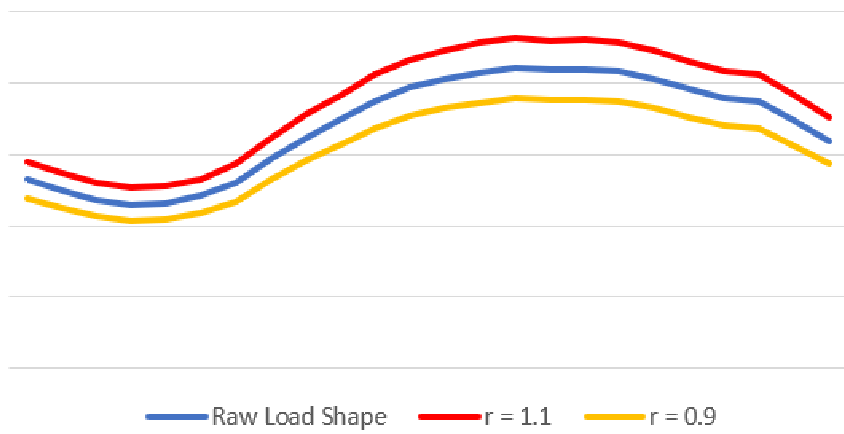
For example, if the historical energy for Load Zone A was 15,349 GWh, and the target annual energy for Load Zone A was 15,964 GWh including BTM:NG load, then $r_A = \frac{15{,}964}{15{,}349} \approx 1.04$

The historical zonal load shapes are scaled up or down by multiplying the hourly load of the historical load shapes by the corresponding zonal energy adjustment ratio $r_{Zone}$.

The zonal energy adjustment ratio is calculated for each zone and all hours in the zone are multiplied by the same ratio.

*Figure 6* below is an illustrative example of how different energy ratio $r_{Zone}$ affects the raw load shape.

*Figure 6 - Energy Adjustment (Illustrative Example)*




### 4.3. NCP Adjustment ("shrink and stretch" method)

Prior to the NCP adjustment, the energy adjusted historical load shapes are separated into summer (May – October) and winter (January – April, November – December) shapes and treated separately.

The NCP adjustment factor $\lambda_{Load_{i,Z}}$, for each load hour is calculated as follows:

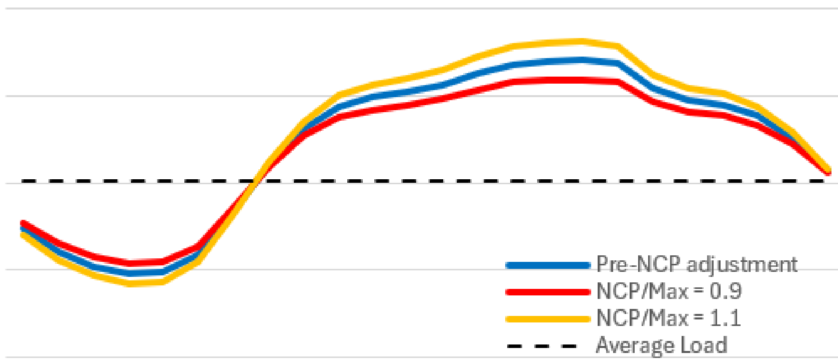
$$\lambda_{Load_{i,Z}} = 1 + \frac{Load_{i,Z} - \overline{Load_Z}}{Max(Load_Z) - \overline{Load_Z}} \times \frac{NCP_Z - Max(Load_Z)}{Max(Load_Z)}$$

where: $Load_{i,Z}$ represents the load value at $i$th (chronological) load hour of Load Zone $Z$, and $\overline{Load_Z}$ represents the average load value of Load Zone $Z$.

Each hourly load value $Load_{i,Z}$ is multiplied by the unique corresponding adjustment factor $\lambda_{Load_{i,Z}}$, (i.e., $\lambda_{Load_{i,Z}} \times Load_{i,Z}$).

Conceptually, this treatment pivots the load shape around the average load value based on the NCP/maximum load ratio. As shown in the illustrative example in *Figure 7* below, if the NCP is smaller than the maximum load, then the updated NCP adjustment proportionally shifts down the load values that are greater than the average load, while shifting up the load values that are less than the average load. Similarly, if the NCP is greater than the maximum load, then the revised adjustment proportionally shifts up the load values that are greater than the average load, while shifting down the load values that are less than the average load. This adjustment method effectively captures the NCP with minimal changes to the previously adjusted energy level.

*Figure 7 - NCP Adjustment - behavior near the average load (Illustrative Example)*




## 4.4. CP Adjustment

The CP adjustment method is similar to the current load shape adjustment method. First, the dates and hours of the historical NYCA seasonal peaks are identified as the target NYCA summer/winter CP hours. The difference $\Delta_Z$, between the scaled historical (after NCP adjustment) summer/winter maximum NYCA load and the forecasted CP of the corresponding season by zone, is then calculated as follows:

$$\Delta_Z = Target\ CP_Z - Scaled\ Historical\ CP_Z$$

For example, if the peak for Load Zone A after the NCP adjustment was 2,000 MW, and the forecasted CP for Load Zone A was 2,050 MW, then $\Delta_A = 2{,}050 - 2{,}000 = 50$. If the scaled historical peak for Load Zone B is 1,900 MW, and the forecasted CP for Load Zone B is 1,880 MW, then $\Delta_B = 1{,}880 - 1{,}900 = -20$.

The scaled zonal demand for the CP hour of each season is then adjusted by the calculated difference $\Delta_Z$ . The resulting zonal CP values are then assessed for alignment with the target value for each zone, using the formula below.

$$Scaled\ Historical\ CP_Z + \Delta_Z = TargetCP_Z$$

To smoothen the load shape around the peak, $0.5 \cdot \Delta_Z$ (50% of $\Delta_Z$) and $0.25 \cdot \Delta_Z$ (25% of $\Delta_Z$) are subsequently added to the $CP \pm 1$ and $CP \pm 2$ hours respectively for each zone.

## 4.5. G–J Locality Peak Adjustment

Similar to the CP adjustment, the dates and hours of the historical G–J Locality seasonal peaks are identified as the target G–J Locality summer/winter peak hours. If the historical G–J Locality peak hour occurs at the same time as the NYCA CP, the hour preceding the NYCA CP hour is identified to serve as the G–J Locality peak hour.

For each zone of the G–J Locality, calculate, using the formula below, the difference $\delta_Z$, between the zonal load of the identified G–J Locality summer/winter peak hour and the corresponding zonal values associated with the forecasted G–J Locality peak.

$$\delta_Z = Target\ GJ_Z - Determined\ GJ_Z$$

The scaled zonal demand for the identified G-J Locality peak hour of each season is then adjusted by the calculated difference $\delta_Z$. The resulting G-J Locality seasonal peak values are then assessed for alignment with the target for each zone, using the formula below:

$$Determined\ GJ_Z + \delta_Z = Target\ GJ_Z$$

### 4.6. NCP Correction

As a result of the CP and G–J Locality peak adjustments, some zones, which were previously adjusted to match the corresponding summer/winter NCP targets, may have deviated from the target. If this occurs, further adjustments are necessary to meet the zonal NCP target.

For each seasonal NCP that has deviated from its target, the hour succeeding the seasonal CP hour is identified to serve as the seasonal NCP hour for the applicable zone and the load value for such hour is adjusted to match the corresponding zonal NCP target.

### 4.7. Energy Recalibration

As a result of NCP, CP and G–J Locality peak adjustments, the zonal energy may have deviated from the target annual energy of each zone. Based on the analysis conducted for this proposal, the average deviation of the modeled annual energy caused by the subsequent peak adjustments was less than 0.15% of the target annual energy at the NYCA level.

For each zone, the delta between the modeled energy and the target annual energy is determined as follows:

$$Energy\ Delta_Z = Target\ Energy_Z - Modeled\ Energy_Z$$

Energy in shoulder months is proportionally adjusted by a zonal factor $\varepsilon_Z$ calculated using the formula below:

$$\varepsilon_Z = 1 + \frac{Energy\ Delta_Z}{Shoulder\ Months\ Energy_Z}$$

Based on the observations from the assessment conducted for this whitepaper, the modeled CP, NCP, and G-J Locality peaks do not occur during the shoulder months (March – May, October – November).

To derive the adjusted hourly energy modeled in the study, each hourly load value, $Load_{i,Z}$ during the shoulder months is multiplied by the corresponding zonal factor $\varepsilon_Z$, i.e., $\varepsilon_Z \cdot Load_{i,Z}$.

### 4.8. External Load Modeling

The same historical load shapes selected for the NYCA (i.e., 2013, 2017, and 2018) are used for the modeling of external areas.

In compliance with NYSRC Policy No. 5,[6] the top three summer peak load days of an external area should be specified in the load model as coincident with the NYCA top three peak load days. This is intended to capture the higher likelihood that there will be considerably less load diversity between the NYCA and external areas on very hot summer days.

With the proposed ELM, the external load shapes are adjusted to ensure that the top three summer and top three winter peak load days for each external area are coincident with the NYCA top three summer and top three winter peak load days.

The seasonal alignment of the top load days is performed by swapping the daily load shape data (the 24-hour period) of the date for each external area to match the dates of the top NYCA load days for each seasonal.

## 5. <u>Results</u>

Using the Tan45 methodology, an impact assessment of the BTM solar modeling enhancements and proposed ELM were conducted on the 2025-2026 IRM FBC. As indicted in the *Table 3* below, the impact assessment demonstrated that the combined modeling of the BTM solar enhancements and proposed ELM produced a 0.8% increase to the IRM, as well as increases to the LCRs.

*Table 3 - Impact Assessment (Tan45)*

| Case Description | IRM | Load Zone J LCR | Load Zone K LCR | G-J Locality |
|---|---|---|---|---|
| **2025–2026 IRM FBC** | 24.40% | 75.58% | 107.30% | 86.91% |
| **+ BTM Solar** | 25.42% (*+1.02*) | 76.49% (*+0.91*) | 108.86% (*+1.57*) | 87.57% (*+0.66*) |
| **+ ELM*** | 24.16% (*-0.24*) | 75.34% (*-0.25*) | 107.46% (*+0.16*) | 86.73% (*-0.18*) |
| **+ BTM Solar and ELM*** | 25.20% (*+0.80*) | 76.04% (*+0.46*) | 108.77% (*+1.47*) | 87.25% (*+0.34*) |

*: The result includes additional Policy 5 adjustments to external areas

The implementation of the explicit modeling of BTM solar alone would increase the IRM by 1.02% due to the probabilistic nature of the BTM solar modeling construct which increases randomness and uncertainty in the model. The Load Zone K LCR demonstrated a greater increase because the quantity of BTM solar in Load Zone K is almost double that of Load Zone J. This result is consistent with the BTM solar sensitivity which was presented as part of in 2024 modeling development efforts.[7]

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[6] NYSRC Policy No. 5-18 06.14.2024: https://www.nysrc.org/wp-content/uploads/2024/06/NYSRC-Policy-5-18-06_14_24-Final.pdf

[7] BTM Solar Modeling Sensitivity – 09.04.2024 ICS: https://www.nysrc.org/wp-content/uploads/2024/08/BTM-Solar-Modeling-Sensitivity-09042024-ICS34671.pdf

The implementation of the proposed ELM alone would decrease the IRM by 0.24%. The primary driver of the impact is attributed to the decreased total energy requirement modeled in the study. Load Zone K LCR sees a small increase because the target energy modeled for Load Zone K using the ELM is greater than the energy that is modeled for Load Zone K for 2025-2026 IRM FBC.

The hourly risk analysis for the 2025-2026 IRM FBC presented in *Figure 8 and Table 4* below show that the combined modeling of the BTM solar enhancements and proposed ELM shift the daily risk to earlier in the day. The shift in daily risk is primarily driven by the BTM solar modeling enhancements. This is because modeling BTM solar as a supply resource increases variability and uncertainty in the probabilistic modeling, leading to greater risk during the day when more solar production is available. The proposed ELM has minimal impacts on the hourly loss of load expectation (LOLE) profile.

*Figure 8 - Hourly LOLE Distribution*

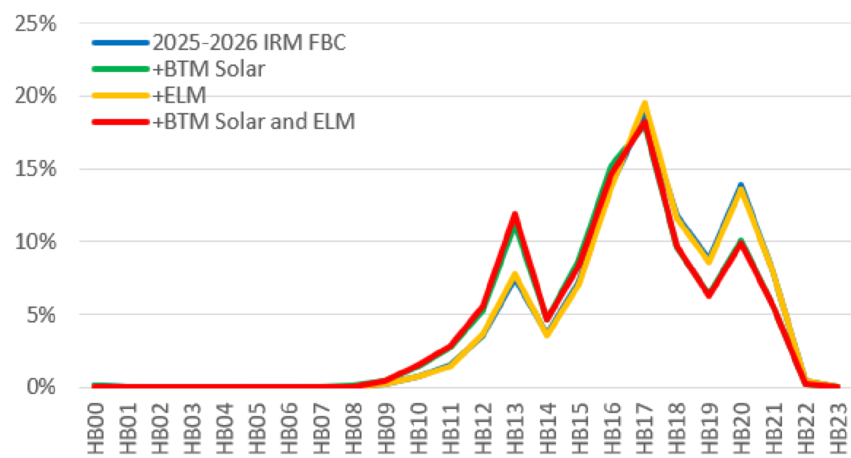


*Table 4 - Hourly LOLE Distribution*

| | HB00 | HB01 | HB02 | HB03 | HB04 | HB05 | HB06 | HB07 | HB08 | HB09 | HB10 | HB11 | HB12 | HB13 | HB14 | HB15 | HB16 | HB17 | HB18 | HB19 | HB20 | HB21 | HB22 | HB23 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2025-2026 IRM FBC | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 1% | 2% | 4% | 7% | 4% | 7% | 14% | 19% | 12% | 9% | 14% | 8% | 0% | 0% |
| + BTM Solar | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 1% | 3% | 5% | 11% | 5% | 9% | 15% | 18% | 10% | 6% | 10% | 6% | 0% | 0% |
| + ELM | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 1% | 1% | 4% | 8% | 4% | 7% | 14% | 19% | 12% | 9% | 14% | 8% | 0% | 0% |
| + BTM Solar and ELM | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 2% | 3% | 6% | 12% | 5% | 8% | 15% | 18% | 10% | 6% | 10% | 6% | 0% | 0% |

The pronounced increase in hourly risk at hour beginning (HB) 13 is primarily driven by the load-side modeling adjustments of BTM solar enhancements. Modeling load on a gross basis result in material increases in the modeled load during the period from HB10-HB13. Under the prior net-of-BTM solar (or "net summer load") modeling convention, the daily average net summer load was highest at HB18. Implementing the BTM solar modeling enhancements result in the daily average gross summer load being highest at HB13. *Table 5* below shows the change in average daily summer load profiles.

*Table 5 – Daily Weighted-Average Summer Load*

| HB | Net Summer Load (MW) | Summer BTM Solar (MW) | Gross Summer Load (MW) |
|---|---|---|---|
| 0 | 15873.6 | 0.0 | 15873.6 |
| 1 | 15153.0 | 0.0 | 15153.0 |
| 2 | 14696.5 | 0.0 | 14696.5 |
| 3 | 14509.3 | 0.0 | 14509.3 |
| 4 | 14698.4 | 6.6 | 14705.0 |
| 5 | 15427.0 | 133.0 | 15560.0 |
| 6 | 16536.8 | 562.0 | 17098.8 |
| 7 | 17406.0 | 1281.3 | 18687.3 |
| 8 | 17783.3 | 2089.1 | 19872.4 |
| 9 | 17869.9 | 2779.2 | 20649.1 |
| 10 | 17883.7 | 3245.0 | 21128.6 |
| 11 | 17926.9 | 3428.8 | 21355.7 |
| 12 | 18095.5 | 3381.0 | 21476.4 |
| 13 | 18399.7 | 3126.2 | 21525.8 |
| 14 | 18800.7 | 2653.8 | 21454.5 |
| 15 | 19384.4 | 1979.4 | 21363.8 |
| 16 | 20109.8 | 1198.6 | 21308.4 |
| 17 | 20724.2 | 533.6 | 21257.8 |
| 18 | 21008.5 | 142.3 | 21150.8 |
| 19 | 20989.3 | 7.4 | 20996.7 |
| 20 | 20630.0 | 0.0 | 20630.0 |
| 21 | 19728.5 | 0.0 | 19728.5 |
| 22 | 18332.3 | 0.0 | 18332.3 |
| 23 | 16950.5 | 0.0 | 16950.5 |

## 6. Recommendation

Based on the research and analysis conducted and summarized herein, the BTM solar modeling enhancements and the proposed ELM provides a better representation, and an improvement of the load and resource modeling reflected in the IRM study. As a result, adoption of the BTM solar modeling enhancements and proposed ELM is recommended for the 2026-2027 IRM PBC.

## References

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