ATTACHMENT A

Consolidated Edison Company of New York, Inc.

January 2026 Reliability Needs Report

ISSUED: JANUARY 20, 2026

CASE 25-E-0764

1. Executive Summary

On December 18, 2025, the Commission directed Con Edison to develop a "NYC Reliability Contingency Plan" and to begin by filing a report with the Commission identifying the specific reliability needs that Con Edison sees arising in its service territory, the dates of those needs, and the underlying assumptions and methodologies used in determining those needs.[1] The Commission further directed Con Edison to update its analysis every six months.

As of January 2026, Con Edison projects a reliability need in the New York City 345/138 kV Transmission Load Area (TLA)[2] of 125 MW in 2032, reaching 750 MW by 2036. The details behind this assessment are explained in this report as required by the Commission.

The January 2026 reassessment[3] refines and updates the December 2025 preliminary assessment Con Edison presented at the NYISO.[4] In December 2025, Con Edison identified reliability needs starting at 250 MW in 2030 and increasing to 1,325 MW in 2035, based on the Company's 2024 load projection. The January 2026 reassessment incorporates 2025 load projections, which use the 2025 Distribution Load Area (DLA) peak demand forecast using a more granular 24-hour load modeling methodology which reduced the reliability need, offset in part by a 175 MW reduction in capacity sales from PJM, which increased the need.

Further, Con Edison projects capacity shortfalls in the overall New York City 345/138 kV TLA to continue to grow beyond the planning period covered by this report, reaching 925 MW by 2037 and 2,350 MW by 2045. These increasing capacity shortfalls result from a large number of factors, some of which offset each other. On the customer and demand side, shortfalls are driven principally by continued economic growth in New York City as well as building and transportation electrification aided by state and local programs that advance the ambitious goals established by the Climate Leadership and Community Protection Act (CLCPA), and offset partially by the adoption of distribution battery energy storage systems (BESS) and continued increases in energy efficiency. On the supply side, the shortfalls are driven primarily by generation retirements and state law limiting electric generation emissions, offset in part by gradual ramping up of intermittent clean and renewable development. The net impact of these dynamic factors in the demand and supply balance results in the expectation that capacity shortfalls in Con Edison's Transmission District will rise significantly.

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[1] Case 25-E-0764, Proceeding on Motion of the Commission to Address New York City Reliability Needs, Order Initiating Proceeding and Directing Reliability Contingency Plan (December 18, 2025) (Order).

[2] As defined in the NYISO Open Access Transmission Tariff (OATT), a Transmission District is "the geographic area in which a Transmission Owner, including LIPA, is obligated to serve Load, as well as the customers directly interconnected with the transmission facilities of the Power Authority of the State of New York." *See* NYISO OATT, Section 1.20.

[3] Typically, the information underlying the January 2026 reassessment would receive further Company review before being finalized, but Con Edison is filing this report now at the Commission's direction. The Company will continue its review and update this report in six months, as required by the Commission. As the Company continues to review the data underlying the January 2026 reassessment, it may refine its conclusions.

[4] Con Edison presented its December 2025 assessment as part of its preliminary Local Transmission Plan (LTP) at NYISO's December 3rd joint meeting of the Electric System Planning Working Group and Transmission Planning Advisory Subcommittee. At that time, Con Edison indicated that it would update its LTP in early 2026.

2. Introduction

Con Edison is required to develop a Local Transmission Plan as part of NYISO's Comprehensive System Planning Process[5] and to post[6] its Transmission Planning Criteria (Specification TP-7100[7]*)* and Local Transmission Planning Process study assumptions[8] on its public website. Con Edison's criteria meet or exceed the standards established by the North American Electric Reliability Council (NERC), the Northeast Power Coordinating Council (NPCC), and the New York State Reliability Council (NYSRC). Additionally, Con Edison must consider comments from customers, market participants, and other stakeholders regarding the posted materials. Con Edison received no comments on the assumptions for this cycle.

Con Edison initiated its Local Transmission Planning Process for its Transmission District in mid-2025. Based on load projections developed at the initiation of the 2025 Local Transmission Plan (LTP), Con Edison identified a deficiency within its New York City 345/138 kV TLA. These results were presented as preliminary in December 2025 to the NYISO stakeholder committee[9] meeting and posted publicly. Subsequently, Con Edison has refined its analysis to reflect its 2025 DLA peak demand forecast and preliminary LTP assessment — which uses a more granular 24-hour model and incorporates updated modeling assumptions. As a result, the January 2026 reassessment reflects a later and reduced need than the December 2025 preliminary assessment: the deficiency is now projected to emerge in 2032 at 125 MW, growing to 750 MW by the end of the shifted planning horizon in 2036 (2027–2036).

3. Assumptions

The January 2026 reassessment is based on the system represented in the database derived from the 2025 NYISO FERC Form No. 715 filing(s) and NYISO Load & Capacity Data "Gold Book." The database was further updated consistent with the NYISO Reliability Planning Process practices, rules, and procedures.

The FERC Form No. 715, or the Annual Transmission Planning and Evaluation Report, is a mandatory federal filing that provides the most granular technical snapshot of the United States' high-voltage transmission grid. FERC 715 contains highly sensitive data used primarily by engineers and regulators for advanced power system modeling. Power Flow Base Cases are the core "database" component, consisting of mathematical models (often in PSS/E format) that simulate the physics of the grid. They show exactly how power moves across lines, including voltages, real/reactive power flows, and

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[5] Each CSPP cycle commences with Transmission Owners providing data via their Local Transmission Planning Process for the Reliability Planning Process (RPP), covering years four through ten of a study period. This occurs alongside NYISO's Short-Term Reliability Process (STRP), which covers years one through five following the Short-Term Assessment of Reliability (STAR) start date. The NYISO CSPP and STRP are approved by the Federal Energy Regulatory Commission (FERC), with requirements detailed in Attachments Y and FF, respectively, of the NYISO OATT. The next CSPP cycle will begin with the 2026 RPP, consisting of two key studies: the Reliability Needs Assessment (RNA) and the Comprehensive Reliability Plan (CRP). See https://nyisoviewer.etariff.biz/ViewerDocLibrary/MasterTariffs/9FullTariffNYISOOATT.pdf

[6] NYISO OATT Section 31.2.1

[7] See https://www.coned.com/-/media/files/coned/documents/business-partners/transmission-planning/transmission-planning-criteria.pdf?la=en

[8] https://www.coned.com/en/business-partners/-/media/files/coned/documents/business-partners/transmission-planning/2025-long-range-plan-study-assumptions.pdf

[9] ESPWG/TPAS

transformer settings under various seasonal and future load conditions. The database is Critical Energy Infrastructure Information (CEII) and can be requested from the NYISO.[10]

The NYISO Load & Capacity Data Report,[11] commonly known as the "Gold Book," is an annual comprehensive publication that serves as the definitive technical record for New York State's electric grid. It provides detailed historical data and forecasts for electricity demand (load) and the available supply (capacity) from generating units and transmission facilities.

3.1 Load Projections

3.1.1. Background

The January 2026 reassessment relies on a ten-year load projection predicated on the Company's most recent Summer DLA Peak Demand Forecast, which was finalized in November 2025. The Summer DLA Peak Demand Forecast is produced annually to provide the Company with an outlook of the 24-hour peak day projections for each of the 97 unique load areas (83 networks and 14 non-networks) that comprise Con Edison's electric system's grid. After completion, the DLA Peak Demand Forecast is provided to transmission and distribution planning teams.

Due to a diverse service territory and uniqueness of load areas, the Summer DLA Peak Demand Forecast independently projects future demand for each load area. Each forecast begins with a Weather-Adjusted Peak, which is an estimate of what the actual peak demand for the DLA would have been if design conditions had occurred based on the most recent summer experience.

The forecast then considers the factors that increase and decrease the summer peak day demand for each DLA. The factors considered in the forecast that increase demand include traditional new business, climate change, electric vehicles, and building electrification. Factors that reduce demand include photovoltaic generation, distributed generation and combined heat and power, and energy efficiency (organic and programmatic). The impact from distribution BESS is also included, but their effect can be either increase or decrease demand, depending upon their expected charging and discharging schedules. These factors, often referred to as forecast load modifiers, are each described in the Appendix to this report.

The Company has developed a proprietary Reforming the Energy Vision/Distributed Energy Resources (REV/DER) forecasting tool to generate forecasts for five load-modifying technologies: BESS, Building Electrification (BE), Electric Vehicles (EV), Photovoltaics (PV) and Distributed Generation and Combined Heat and Power (DG/CHP). It uses a highly customized set of technical and behavioral assumptions to assess peak demand impacts for each DLA. The Appendix explains in detail how this forecasting tool is used to calculate each of these forecasts.

The modifier forecasts incorporate policy considerations at local, state, and federal levels through the modeling inputs, reflecting their influence on technology adoption and market trends. For example, the anticipated impacts of New York's CLCPA and supporting legislation, such as Local Law 97, are embedded within these inputs. To clarify, while all policies are considered, the forecasts do not necessarily assume policy goals will be met simply because they exist; rather, they incorporate the

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[10] See nyiso.tfaforms.net/187

[11] See 2025-Gold-Book-Public.pdf

expected progress made towards goal achievement from existing or anticipated incentive program funding or legislative action while also factoring in customer economics when adopting these new technologies. Additionally, recognizing that future government administration changes may lead to policy volatility at the local, state, and federal levels, the Company acknowledges that increased uncertainty is a particularly important and expected characteristic of future forecasts.

The 2025 Summer DLA Peak Demand Forecast is the first time the Company has incorporated each modifier of the forecast (e.g. EV, BESS, etc.) on a 24-hour basis. This has resulted in a final output that forecasts each hour of a peak day rather than just a single peak hour. The general approach is to stack each of the modifiers onto one another to generate each load area's 24-hour forecast showing peak demand at design criteria. As expected, each modifier displays distinct characteristics that cause distinct impacts varying both in magnitude and in time of the peak day. The stacking approach allows the aggregated modifiers to determine the expected peak hour for each load area. This method enhances the Company's understanding of how modifiers impact the peak day and enables the Company to detect shifting peak hours and identify the potential for changing load shapes within each load area across the forecast horizon.

The Company's most recent Summer DLA Peak Demand Forecast is the basis for the January 2026 reassessment while the December 2025 preliminary assessment used load projections based on the Company's 2024 Summer DLA Peak Demand Forecast. As with any comparison of forecast vintages, there are differences in projected values. While no modifier remains stagnant across vintages, notable differences include the following three factors. The first is the Company's transition from forecasting a single peak hour to forecasting each of the 24 hours of the peak day. This enhancement requires all modifiers of the forecast to be in a 24-hour format resulting in increased visibility and application of each modifier. [12] The second factor is due to policy changes incorporated into the forecasts. The Company's forecasts consider policy changes at local, state, and federal levels which dynamically impact load-modifying technology adoption. It is at the federal level, with the expiration of tax incentives and the implementation of restrictive tariffs, where the greatest impact is expected. The third factor is an increase in the Company's interconnection queue for BESS over the past year. The sizable surge in BESS projects signing interconnection agreements is seen as a key milestone toward project completion and resulted in a significant impact to the overall forecast change.

Because the Company's forecasting is a fully integrated process, with policy-driven impacts, shifts in customer plans, market activity such as the surge in BESS projects and routine technical updates all assessed within a single, unified framework, precisely quantifying the influence of any one driver is not possible. Moreover, the methodological change to forecasting each of the 24 hours of the peak day makes directly comparing the 2024 and 2025 Summer DLA Peak Demand Forecasts difficult, particularly at the load-modifier level. Under the new 24-hour approach, the DLA peak hour can vary across the 24-hour period. As a result, a comparison may unintentionally be made between a morning peak hour in 2024 and an overnight peak hour in 2025. These peak hours represent fundamentally different customer demand profiles and contributions from load modifier forecasts. The Appendix provides additional detail regarding each modifier as developed in the most recent Summer DLA Peak Demand Forecast used in this reassessment.

[12] As noted, the 2024 Summer DLA Peak Demand Forecast informed the load projections used in the December 2025 preliminary assessment. The 2025 Summer DLA Peak Demand Forecast informed the load projections used in the January 2026 reassessment.

Con Edison and NYISO coordinate regularly throughout each year's forecasting cycle to discuss methodologies and assumptions, and to exchange information regarding their respective forecasts. Because the forecasts are produced independently of one another, Con Edison's and NYISO's forecasts do differ, primarily in their geographic scopes, peak hour definitions, and underlying data inputs, which can produce different assessments of reliability needs.

Con Edison, for example, prepares a system-wide peak demand forecast for its entire electric service territory, encompassing New York City and Westchester County, in addition to individual forecasts for 97 DLAs, each based on its respective peak hour. The 97 DLA forecasts are provided to Con Edison's transmission and distribution planning teams. By contrast, NYISO publishes coincident peak demand forecasts for NYISO Load Zone J, which includes New York City but excludes Westchester County, and which aligns with the statewide New York Control Area (NYCA) coincident peak hour. This Zone J/NYCA coincident peak hour can differ from Con Edison's system peak hour. NYISO also publishes and uses in its reliability assessments non-coincident summer peak forecasts for applicable zones, which are independent of the system-wide peak.

In addition to these geographic and structural distinctions, Con Edison incorporates granular, bottom-up data sources into its forecasting process, including customer service requests, applications for new or expanded service, and associated load letters. The Company further leverages AMI data to analyze usage profiles of emerging customer segments within its service territory, such as commercial and residential battery and PV installations and buildings with electric heating. Additionally, Con Edison integrates clean energy policy considerations into its forecasting methodology to account for anticipated adoption of load-modifying technologies and their potential impact on system conditions, as NYISO also does, though its assumptions may differ.

3.1.2. Load Projections used in Power Flow

Con Edison's power flow assessment is underpinned by a highly granular, ten-year forecast, which is updated annually to reflect evolving policy mandates, shifting demographic and localized economic drivers. This forecast is developed for each of the 97 unique distribution load areas (comprising 83 secondary networks and 14 non-network radial areas) that constitute the Con Edison electric system.

Upon completion, the forecast is integrated into the Transmission and Distribution planning framework. The Transmission planning team, using specific localized data from Distribution planning, aggregates these granular forecasts into 17 distinct TLAs. This methodology produces a specialized Load Projection that accounts for the unique load shapes and 'coincidence factors' of each area. By establishing independent peak conditions for each TLA rather than relying on a singular system-wide peak, Con Edison can more accurately identify localized constraints and determine the actual maximum peak demand requirements for specific corridors of the 345 kV and 138 kV systems.

The following is Con Edison's load projection, specifically tailored to one of the 17 TLAs, the NYC 345/138 kV TLA, establishing an independent peak condition for this TLA.

Con Edison's 2024 Electric System load projection for years 2026 through 2035, is as follows:

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Load	11,091	11,397	11,646	11,908	12,302	12,516	12,733	12,953	13,203	13,458

Con Edison's 2025 Electric System load projection for years 2027 through 2036, developed during the on-going process of refining and updating the LTP, is as follows:

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Load	11,277	11,443	11,642	11,783	11,922	12,049	12,186	12,311	12,542	12,700

Con Edison's 2025 Electric System load projection long-term for years 2037 through 2045, is as follows:

	2037	2038	2039	2040	2041	2042	2043	2044	2045
Load	12,867	13,034	13,213	13,388	13,562	13,733	13,905	14,076	14,242

3.2 Generator Retirements / Additions

Both January 2026 and December 2025 assessments are based on the system represented in the database derived from the 2025 NYISO FERC 715 filing(s) and NYISO Load & Capacity Data "Gold Book."

Key assumptions related to generation resources for the 10-year Planning Horizon (NYC only):

- Gowanus 2 and 3 and Narrows 1 and 2: Assumed to be out-of-service.
- The New York Power Authority (NYPA) Small Gas Plants: Assumed an equivalent amount of generation is available, pending the outcome of the ongoing assessment detailed in the NYPA Small Natural Gas Power Plant Transition Plan.
- Empire Wind Off-Shore Wind (OSW): Assumed to be in-service beginning in 2027.

Additionally, Con Edison continues to model the Champlain Hudson Power Express (CHPE) HVDC connection from Quebec, Canada to New York City as in-service starting in 2026. This aligns with the "planned" scenario (in contrast to NYISO's "Status Quo" scenario) used in the NYISO Short-Term Assessment of Reliability (STAR) report.[13]

3.3 Transmission Reconfigurations

3.3.1. Local Transmission System Upgrades / Reconfigurations

Both January 2026 and December 2025 assessments assume the following local system upgrades that result in system topology changes:

- Starting in Year 2034: Establish Sunset Park 345 kV Substation as a double-ring bus configuration intercepting 345 kV feeders 25 & 26 that run between 345 kV Goethals and Gowanus substations.
- Starting in Year 2034: Establish Industry City 27 kV Distribution Area Station with three 93.3 MVA 138/27 kV transformers and 30 MVAR capacitors to be supplied from 345 kV Sunset Park Substation.

[13] Short-Term Assessment of Reliability: 2025 Quarter 3, October 13, 2025, available at: https://www.nyiso.com/documents/20142/39103148/2025-Q3-STAR-Report-Final.pdf/86d4e2d9-e1eb-475b-c5db-ee5de81ea799

- Starting in Year 2034: Transfer (about 120 MW) from Greenwood 27 kV Distribution Area Station to Industry City 27 kV Distribution Area Station.

Moreover (for information only), the following projects are currently under construction and were already included in the 2025 NYISO FERC 715 filing(s) and NYISO Load & Capacity Data “Gold Book” database:

- Starting in Year 2026: New transmission path: 4th 345/138 kV PAR controlled Gowanus – Greenwood feeder
- Starting in Year 2028: New transmission substation: 138kV Eastern Queens Substation
- Starting in Year 2028: New transmission substation: 345kV Brooklyn Clean Energy Hub

3.3.2. Feeders A-2253, B-3402 and C-3403

Tie feeders B-3402 and C-3403 continue to be on a long-term outage. The flow assigned to tie feeder A-2253 is based on the NYISO/PJM Joint Operating Agreement. This assumption is carried throughout the 10-year study and are reflected in both the January 2026 and December 2025 assessments.

4. Assessment

Con Edison’s Transmission System is divided into 17 TLAs. In determining the reliability of each of the TLAs relative to the established design criteria, transmission and/or generation resource constraints are evaluated. In addition, each TLA’s design contingency level depends on its Bulk Power System (BPS) or Bulk Electric System (BES) status. A TLA may be designed to Second contingency (N-1/-1/-0) or to First contingency (N-1/-1). The list of Con Edison’s TLAs with their design contingency level can be found in Specification TP-7100 *Transmission Planning Criteria*.

The study uses the Siemens PTI PSS®E and Powered TARA programs.

4.1 New York City 345/138 kV TLA – Criteria

Con Edison NYC 345/138 kV TLA is designed (and operated) for the occurrence of a Second Contingency. Con Edison’s definition of a Second Contingency means that a TLA is planned to withstand, at peak customer demand, the most severe of two independent contingencies and return the electrical system within its normal parameters, expressed as N-1/-1/-0. This is the sequence:

- The "N" represents the system in its normal state (I.e., all generators, transmission lines, transformers, etc. are operating in-service within normal parameters).
- The “N-1” is a basic standard for reliability (The system is constantly operated – in technical terms “secured – to an N-1). The system must be able to handle a single contingency without causing a power outage or damage to equipment. In this case the rest of the system immediately and automatically reroutes the power through remaining transmission after a contingency has occurred (the remaining equipment handles the full load). There is no planner (or operator) action.
- The “N-1/-0” is an intermediate step where the planner (or operator) has a short time to adjust the system to stabilize it after the first loss. This could mean turning on a generator (or ramping

up generator output, etc.), rerouting power flows, etc. The goal is to get the system into a normal state ready to withstand another event.

- The "N-1/-1" represents the system in a state with one element already is out-of-service with second contingency occurring. Again, like step N-1, the system must be able to handle this contingency without causing a power outage or damage to equipment. The rest of the system immediately and automatically reroutes the power through remaining transmission after a contingency has occurred (the remaining equipment handles the full load). There is no planner (or operator) action.
- The "N-1-/1/-0" is the final step where the planner (or operator) has a short time to adjust the system to stabilize it after the second loss. This could mean turning on a generator (or ramping up generator output, etc.), rerouting power flows, etc. Again, like N-1/-0 state, the goal is to get the system into a normal state.

Essentially, N-1/-1/-0 is a planning requirement to ensure the electrical system is reliable enough to survive the two worst, sequential, and independent contingencies.

4.2 New York City 345/138 kV TLA – Assessment

In the case of Con Edison NYC 345/138 kV TLA, the reliability needs were established under the sequential and independent loss of CHPE (at 1,250 MW) followed by loss of Ravenswood 3 (at 986.8 MW), whereas multiple 345 kV and 138 kV feeders were identified to be above their normal operating parameters (i.e., overloaded).[14] To bring back the loading below the normal operating parameters additional – proxy (or compensatory) – generation was inserted downstream of the feeders. The proxy (or compensatory) injection represents the magnitude of the need.

The December 2025 preliminary assessment identified a reliability need within the New York City 345/138 kV TLA for the ten-year planning horizon (2026–2035) beginning in 2030 at 250 MW and reaching 1,325 MW by 2035 (See Table 1).

Table 1: New York City 345/138 kV TLA Reliability Needs (Y2024 Load Projection)

	2026-2029	2030	2031	2032	2033	2034	2035
Peak MW Need	-	(250)	(450)	(575)	(800)	(1,050)	(1,325)
Hours	-	4	7	7	9	11	12
Duration	-	3PM-7PM	1PM-8PM	1PM-8PM	noon-9PM	11AM-9PM	11AM-11PM
Approx. MWh	-	(700)	(1,800)	(2,650)	(4,475)	(6,900)	(10,000)

[14] The assessment tested every possible combination of design contingencies to determine which two sequential and independent events would result in the worst-case scenario.

The January 2026 reassessment, which refined the December 2025 assessment as discussed in this report, reflects a deferred and reduced need. The requirement is now projected to begin in 2032 at 125 MW, growing to 750 MW by the end of the shifted planning horizon in 2036 (2027–2036) (See Table 2).

Table 2: New York City 345/138 kV TLA Reliability Needs (Y2025 Load Projections)[15]

	2027-2031	2032	2033	2034	2035	2036
Peak MW Need	-	(125)	(275)	(400)	(600)	(750)
Hours	-	3	4	5	6	9
Duration	-	- - - 15-16 16-17 17-18 - - -	- - 14-15 15-16 16-17 17-18 - - -	- - 14-15 15-16 16-17 17-18 18-19 - -	- 13-14 14-15 15-16 16-17 17-18 18-19 - -	12-13 13-14 14-15 15-16 16-17 17-18 18-19 19-20 20-21
~MWh by Hour	-	- - - 15-16: 125 16-17: 25 17-18: 50 - - -	- - 14-15: 100 15-16: 275 16-17: 175 17-18: 225 - - -	- - 14-15: 200 15-16: 400 16-17: 300 17-18: 375 18-19: 150 - -	- 13-14: 175 14-15: 375 15-16: 600 16-17: 525 17-18: 575 18-19: 350 - -	12-13: 75 13-14: 300 14-15: 525 15-16: 750 16-17: 675 17-18: 750 18-19: 500 19-20: 150 20-21: 50
Approx. MWh	-	(200)	(775)	(1,425)	(2,600)	(3,775)

It should be noted that the peak demand forecast continues to grow beyond in 2036 and beyond, and New York City 345/138kV TLA would, if unaddressed, continue to experience a growing capacity shortfall. Table 3 projects approximate reliability needs beyond 2036, through 2045.

Table 3: New York City 345/138 kV TLA Needs – Years 2037-45 (Y2025 Load Projections)

	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak MW Need	(925)	(1,100)	(1,300)	(1,475)	(1,650)	(1,825)	(2,000)	(2,175)	(2,350)

The reliability needs identified above are driven by a combination of increasing load demand, cumulative generation retirements, no incremental new generation and loss of generation as the design

[15] The new forecast allows a more dynamic view of how new technologies will impact the shape of the 24-hour load curve.

basis, and assuming the loss of CHPE and Ravenswood, for a total loss of 2,236.8 MW, as the two largest contingencies.

5. Conclusion

This January 2026 reassessment confirms that while the immediate reliability timeline has shifted from 2030 to 2032, the long-term requirement for solutions to address this need remains critical, as the Company is projecting a reliability need of 750 MW by 2036. As the transmission planning process evaluates the impact of major resource additions like CHPE and Empire Wind, generation retirements, and continued load growth, it must do so during a period of considerable uncertainty regarding the supply for that incremental demand. Looking beyond the 10-year planning horizon, capacity shortfalls are projected to grow to 2,350 MW by 2045, underscoring that the system remains in a period of significant transition. The Company will update this report, as required by the Commission's December 2025 Order.

Appendix A.

The following sections provide additional detail regarding each forecast modifier as developed in the Company's most recent Summer DLA Peak Demand Forecast and utilized in the updated January 2026 reassessment.

1. Weather Adjusted Peak (WAP)

The Weather Adjusted Peak (WAP) process is a methodology used to estimate peak electric demand under designed weather conditions. The process begins with careful data selection (elimination of outliers), focusing on periods that best represent the conditions being modeled. Irregular days such as holidays and days affected by outages are analyzed and removed if necessary. Demand Side Management events, such as demand response, voltage reductions, and emergency generator deployment, are measured or estimated and added back to the actual load to reflect the total demand before utility or NYISO controlled resources are dispatched to mitigate demand. Weather variables like temperature, and wet bulb, are incorporated to ensure the model accurately reflects the impact of weather on demand. Model selection is then performed, balancing complexity and accuracy to capture the most representative relationship between customer's demand and the weather variables. The process may involve reviewing multiple years of data, especially when recent years lack extreme weather events.

2. Temperature Variable

Con Edison uses a weather concept called "Temperature Variable" (TV) as a reference point in designing its electric transmission and distribution systems. The TV (equivalent to the "Real-Feel of the Heat") is used to calculate and forecast future system peak demands, considering summer weather conditions sustained high temperatures and humidity over a three-day period, that we would expect to experience in the New York metropolitan area DLAs.

Using a TV factor as a reference point, which incorporates temperature and humidity, is a standard planning practice throughout the utility industry. Con Edison's TV design has been set for some time as 86°. Specifically, the TV factor used for Service Area analysis is calculated as a weighted average of the highest three-hour temperature (called dry-bulb) and humidity (called wet-bulb) readings each day, as registered at the NWS stations at Central Park and LaGuardia Airport. The weather variables for the two stations are re-calculated using Clausius–Clapeyron relation. Merging the two weather stations to calculate TV began in July 2002. Prior to July 2002, the Central Park station was used exclusively. (Note: Network Area forecasting uses a similar formulation for TV, but links the calculation to network specific weather stations. For example, Westchester networks are reviewed using NWS White Plains data.)

Since heat "buildup" over a hot spell of a few days' duration significantly increases air conditioning use and stress on Con Edison's electric system, the formula for calculating the daily Service Area TV incorporates three days' worth of data. The current day's weather is weighed at 70%, the previous day's at 20%, and two days before at 10%. There is a clear correlation between TV and peak demand.

Note – Maximum effective Wet-Dry Bulb temperature is the average of the three consecutive Wet/Dry hourly temperatures occurring between the hours of 9 a.m. and 9 p.m. yielding the highest Wet/Dry Average.

3. Traditional New Business Forecast

The Traditional New Business modifier accounts for projections of new construction and modifications to existing service. Traditional New Business is distinct from growth arising from emerging technologies such as Electric Vehicles and Building Electrification which are accounted for separately and described further in subsequent sections.

The Company implements two approaches when forecasting load growth attributed to Traditional New Business, a bottom-up approach to help capture the idiosyncrasy of new customer interconnections and locationally-specific load behavior, and a top-down approach to help capture direction and trend. The former leverages vetted customer load requests and applications for new and modified service while the latter relies on econometric modelling. The two approaches are eventually married into a final Traditional New Business forecast.

The bottom-up approach uses submitted applications for new and additional electric service. Each electric service request from a customer is accompanied by a load letter developed under the guidance of a licensed engineer. Load letters list functional uses of load as part of the customer's service request. Job requests that specify load derived from electric vehicle and/or electrification of space heating are flagged with that load excluded from the Traditional New Business projection. A multi-departmental team of subject matter experts comprehensively vets each job request to ensure appropriate service date, DLA, summer load estimate, and ramp rate. This vetting process is only done for new service requests above 100 kVA and additional service requests above 300 kVA. Additionally, "headline jobs" may also be included as a part of Traditional New Business. Headline jobs refer to known jobs that may not have submitted formal load requests but are expected to occur and have an impact on planning efforts.

The top-down approach for Traditional New Business uses econometric modelling which considers various economic indicators to project future anticipated growth. Separate models are estimated for residential growth and commercial growth. Both models are at the system-level and are estimated at an annual periodicity. For dependent variables, historical peak load for residential and commercial customers are used for the respective models. Both models use TV and economic data as independent variables. For economic independent variables, the Company constructs two separate weighted indices – one for the residential model and one for the commercial model. The indices use economic series such as employment, gross metro product, households counts, and real income. Projections of economic series are provided by Moody's Analytics using their Baseline Scenario for New York City and Westchester County. Time-series components are utilized as necessary in the econometric models. After models are estimated and forecasts are produced, system-wide projections are allocated to DLAs based on the load share from the bottom-up method. The first five years of the forecast period exclusively uses the bottom-up method. Beyond year 5 of the forecast horizon, the forecast uses the higher of the bottom-up and top-down method with each DLA independently analyzed. Because job requests tend to markedly decline beyond five years, the top-down method is typically employed for outer years of the forecast. However, there are instances where a DLA's bottom-up projection is greater than its top-down projection beyond the 5th year.

4. Battery Energy Storage Systems Forecast

The BESS modifier forecast models the charging and discharging contribution of customer-owned, distribution-connected batteries to system and DLA loads. First, a list of all BESS units currently installed or in the NYS Standardized Interconnection Requirements (SIR) queue within the Con Edison service territory is generated. Key technical details are considered, including nameplate capacity, customer segment, the presence of paired on-site Solar PV, and the local DLA where the battery will interconnect. Each BESS project is assigned a behavioral segment with distinct assumptions for charging and discharging determined through consultation with internal energy storage project teams, where factors such as the interconnection agreement parameters, compensation mechanism and system size are considered.

The BESS installations forecast (in MW of nameplate capacity) is a combination of bottom-up, queue-based growth and top-down industry growth projections. In the early years of the forecast horizon, the BESS installations forecast is developed using in-queue projects that have signed interconnection agreements. Using estimated in-service dates from internal energy storage teams' detailed tracking of project development stages and timelines, these projects are directly placed into the forecast in the expected year and DLA of interconnection due to their high confidence of completion. In the later years of the BESS forecast, top-down growth rates are derived from data from the most recent Bloomberg New Energy Finance Energy Storage Market Outlook. System-level top-down forecasts are allocated to DLAs based on percentage of combined BESS capacity installed and in-queue. These long-term outlooks reflect the latest policy and market drivers impacting the BESS supply chain and manufacturing, such as recent federal tax policy changes around material assistance from prohibited entities, as well as trade policy (tariffs).

Once the BESS installations forecast has been established, a series of inputs around BESS technical and behavioral assumptions are established to form the peak impact calculation. BESS charging and discharging assumptions are formed using actual AMI performance data analysis of currently installed BESS on peak days, to create representative profiles. Additionally, factors such as compensation mechanism, system size, and the presence of paired Solar PV systems dictate a variety of possible charge and discharge behaviors to be considered. A key driver of the forecast is the Standalone 1-5 MW BESS customer segment, and the VDER value stack compensation mechanism, some components of which incentivize discharging at local DLA peak hour ranges, which may not be coincident with the overall TLA need hours. The full 24-hour charging and discharging profile is considered when evaluating the MW impact of BESS on system and DLA peaks. Over the past year, the BESS interconnection queue has seen a surge in projects signing interconnection agreements, a key milestone toward completion. The operational complexity of these systems, paired with the varying stages of progress among these contracted projects add uncertainty to the forecast, especially as growth approached saturation in several areas in 2025.

5. Building Electrification Forecast

The Building Electrification (BE) forecast estimates how many customers in Con Edison's service territory will replace non-space heating fossil fuel equipment, such as water heaters, dryers, and stoves—with electric alternatives over the next decade. The model is built on a stock and flow framework, where the stock represents the existing fossil fuel load that could be electrified. This stock is developed using internal inputs, including the base natural gas volume forecast adjusted to exclude space heating and previously forecasted BE impacts, as well as external inputs such as heating oil usage data from the NYC Greenhouse Gas Inventory and the U.S. Energy Information Administration.

The flow component captures the rate at which customers electrify, using a scoring system based on macroeconomic conditions, customer economics, laws and regulations, and technical limitations to estimate annual declines in natural gas and oil usage. These annual reductions are then distributed across months using historical natural gas use seasonality. The model converts the resulting fossil fuel reductions into increased electricity demand through a technical conversion process that relies on efficiency assumptions informed by the state's Technical Resource Manual, historical AMI data, and EIA surveys.

Finally, the forecast translates annual changes in electric usage into expected impacts on DLA level peak demand using established ratios and historical load profiles, providing a detailed view of how building electrification will reshape energy consumption throughout the forecast horizon and for each DLA.

6. Climate Change Forecast

The Climate Change modifier is used to account for the impact on peak demand arising from anticipated changes to the service territory's climate such as an increasing TV. The Climate Change forecast modifier relies on information published as part of the Con Edison Climate Change Vulnerability Study (CCVS).16 The Company's most recent CCVS published in September 2023 leverages projections and data provided by the New York State Energy Research and Development Authority (NYSERDA) in partnership with Columbia University. The CCVS was performed by Con Edison with assistance from consultant ICF.

The 2023 CCVS projects an 89° TV in 2051 which is used as an endpoint to extrapolate from the Company's present design criteria of 86° TV. To estimate the megawatt impact from a rising TV, the slope from a system-wide WAP regression model is used. This value is then proportionally allocated to each of the load areas based on historical load share to produce the Climate Change modifier.

7. Distributed Generation/Combined Heat and Power Forecast

The DG/CHP forecast encompasses the following technologies: Internal Combustion Engines, Gas and Steam Turbines, Fuel Cells, Microturbines, and Combined Heat and Power. It segments the forecast into Large DG/CHP (capacity >= 1 MW) and Small DG/CHP (capacity < 1 MW) and provides data at both the system and DLA levels. First, a list of all DG/CHP units currently installed or in the NYS Standardized Interconnection Requirements (SIR) queue within the Con Edison service territory is generated, including details such as their nameplate capacity, technology type, and associated DLAs.

The DG/CHP Installations forecast (in MW of nameplate capacity) is a combination of bottom-up, queue-based growth and top-down industry growth projections. In the early years of the forecast horizon, the Large DG/CHP forecast is developed using in-queue projects with accurate estimated in-service dates from internal DG teams' detailed tracking of project development stages and timelines. In the later years of the Large DG/CHP forecast, top-down growth rates are derived from the historical pace of installations. Small DG/CHP forecasts apply top-down growth across all 20 years based on the historical pace of installations. System-level top-down forecasts for both Large and Small DG/CHPs are allocated to DLAs based on completed and pending DG capacity (excluding NWS & EE). Another factor considered in the installations forecast is DG/CHP retirements by facility owners seeking to comply with Local Law 97 (LL97). Based on internal Company estimates of penalties that some large, fossil-fuel powered DG/CHP owners could face, and when those owners would be faced with a decision between paying LL97 penalties or retiring their CHP system, the Company includes the predicted impact that these retirements would have on the peak demand of the local DLA. Customer outreach regarding operational

[16] Con Edison Climate Change Vulnerability Study

plans related to LL97 is often required to accurately estimate the law's impact on Large CHP owners in an ever-evolving policy landscape.

The DG/CHP electric peak impact calculation uses performance factors for both large and small existing technologies. This reflects their utilization rate based on last year's usage, validated through AMI data analysis, and nameplate ratings. These factors forecast future DG/CHP usage based on the rated capacity of operating units. By multiplying the performance factors with the nameplate capacities, we determine peak impact, assuming new units will operate similarly to existing ones.

8. Electric Vehicles Forecast

The EV forecast considers the demand associated with Level 1, Level 2, and Direct Current Fast Charging infrastructure. It encompasses anticipated load from both Light-Duty Vehicles (LDVs) and Medium- and Heavy-Duty Vehicles (MHDVs) within the Con Edison service territory over a 10-year planning horizon. In addition to these forecasts, it integrates demand originating from charging infrastructure projects currently in the customer project queue, ensuring alignment with near-term developments.

The EV fleet forecast includes detailed projections for both LDVs and MHDVs within the Con Edison service territory over the 10-year forecast horizon. The LDV forecast is developed using external scenario-based studies that account for varying levels of policy compliance, incorporating assumptions about regulatory adherence, incentive programs, and evolving market dynamics. These scenario insights are then integrated with historical EV registration data from the DMV and aligned with state policy targets to produce a comprehensive projection of future LDV adoption. The 2025 LDV adoption forecast reflects the anticipated impact of federal tax credit 30D's expiration, a development likely to reduce consumer demand and overall market growth. The forecast also incorporates historical patterns in consumer choices between full Battery Electric Vehicles and Plug-in Hybrid Electric Vehicles to project future trends.

The MHDV forecast spans nine distinct vehicle segments, including multiple classes of trucks, transit buses, and school buses. Electrification rates for these segments are informed by Advanced Clean Trucks Act sales targets and specific fleet electrification goals, with adjustments applied to account for potential policy non-compliance through a dedicated factor. This factor accounts for potential funding limitations and other barriers that could impact fleet conversion timelines. The 2025 MHDV adoption forecast accounts for the combined impact of federal tax credit 45W's expiration and the postponement of Advanced Clean Trucks Act enforcement, both factors expected to extend fleet electrification timelines. This comprehensive approach ensures that the forecast accurately reflects the expected growth and adoption of both LDVs and MHDVs in the service territory.

The methodology integrates a wide range of technical assumptions, including vehicle efficiency, battery size, degradation rates, and annual vehicle miles traveled. Charging behavior is modeled using Electric Vehicle Supply Equipment (EVSE) datasets, which detail the expected distribution of energy consumption across different charging locations and EVSE types. These datasets also inform assumptions about the share of energy delivered at home, public, and depot charging stations.

In addition, the forecast also integrates technical assumptions and charging behavior patterns. This includes the anticipated percentage of vehicles starting to charge during each hour of the day and the percentage of EVs participating in managed charging programs. These projections are informed by historical enrollment trends in the SmartCharge NY program and expected future growth.

Each input, including adoption forecasts and technical parameters, contributes to developing a top-down EV demand forecast that reflects expected growth driven by regional EV trends. To complement this, customer project data is incorporated by aggregating demand from requests for new or additional service connections associated with EV charger installations. When the projected demand from these customer projects exceeds the top-down forecast, that higher value is used to define the magnitude of the EV load curves. This robust approach ensures that the forecast remains aligned with actual market activity and is responsive to emerging needs.

9. Energy Efficiency Forecast

The energy efficiency (EE) forecast is an estimate of peak demand reduction as a result of customers reducing their use of electricity, either because they have taken part in EE programs offered by the Company, NYSERDA or NYPA, or because of improved building codes and energy performance standards. The forecast is provided as MW of peak reduction for each hour of the summer peak day, for each load area in Con Edison's system, and is separated between programmatic and non-programmatic (organic) energy efficiency.

The peak reduction MW values are developed by combining separate EE volume (MWh) forecasts for lighting, HVAC equipment, and other EE activities, using stock and flow models for the former two and an index model for the latter. EE volumes are developed using program projections and estimates of natural adoption for different EE technologies, modified to account for free ridership and other factors. A forecasting model is employed that allocates total EE volume by load area and end use, applies a combination of hourly load shapes to estimate the peak load reduction impact of EE for each end use, and then sums the results to obtain an estimate of peak load reduction for each load area.

10. Photovoltaics Forecast

This forecast projects PV panel installations and peak demand reductions from PV panel output in the Con Edison service territory over a 10-year period. It segments the forecast into PV Large (units over 25kW) and PV Small (units under 25kW) and provides data at both the system and DLA levels. Twenty-five kW was selected as an approximate divider between residential and commercial projects in order to apply the lead times of large and small PV projects to the forecast.

A list of solar projects in the SIR interconnection queue within the Con Edison service territory is compiled, categorizing projects as completed, in-queue, or canceled. The list includes details such as project number, status, and AC nameplate capacity (kW). The installed base is determined by accounting for completed projects and applying degradation factors.

The Company employs a combination of methods to forecast PV installations. In the latest peak forecast, a blend of queue-based/statistical approach and moving average methodology was applied. Within the queue-based/statistical approach, parameters such as cancellation rate, completion cycle, and average project size are calculated and used to estimate the completion of existing queued projects. Once the current queue is depleted, future cumulative capacity is forecasted for new projects projected to enter the interconnection queue, leveraging historical trends. The resulting installation forecast is then allocated across the networks based on historical shares of in-queue and completed projects. Additionally, a policy adjustment was incorporated to reflect the recent termination of the 25D and 48E federal tax credits which are both expected to slow down the adoption of solar panels.

After the PV installation forecast is developed and allocated to the various networks, a 24-hour solar generation curve (SGC) is applied to this forecast to arrive at peak impact at the hourly level. This 24-hour SGC is updated annually, using AMI data from approximately 800 solar customers with dedicated panel telemetry. This curve calculates the average peak impact as a percentage of the nameplate capacity of solar panels for each hour of the day.