March 16, 2026

VIA ELECTRONIC FILING
Hon. Michelle L. Phillips
Secretary to the Commission
New York State Public Service Commission
Three Empire Plaza
Albany, New York 12223

Re: 15-E-0751 and 19-E-0283 – In the Matter of the Value of Distributed Energy Resources

Dear Secretary Phillips:

NineDot Energy (NineDot) appreciates the opportunity to provide these comments to the Department of Public Service (DPS) Staff in response to DPS Staff Proposal on Updating DRV and LSRV for VDER Compensation in the Matter of the Value of Distributed Energy Resources.

We are available to discuss these comments further and can be reached at linda@nine.energy or +1-917-843-4878.

Respectfully submitted,

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I. Executive Summary

NineDot Energy (NineDot) appreciates the opportunity to provide comments on the Department of Public Service Staff (DPS) Proposal to update the Demand Reduction Value (DRV) and Locational Service Relief Value (LSRV) components of the Value of Distributed Energy Resources (VDER) Value Stack framework. NineDot commends the Commission and Staff for the significant work that has gone into this proceeding and the thoughtful approach to the current proposal. Marginal Cost of Service (MCOS) studies play a critical role in establishing pricing signals that ensure distributed energy resources (DERs) are compensated based on the long-run marginal costs they avoid on the electric system. When implemented correctly, these signals can unlock cost-effective, clean, and straightforward alternatives to traditional utility infrastructure investment while maintaining or enhancing system reliability.

The deployment of VDER-based BESS resources advances several important policy objectives established by the Commission and the State of New York. These include:

- **Allowing for billions of dollars in ratepayer savings through the deferral of expensive traditional transmission, area substation, load transfer, primary and secondary feeder, and transformer infrastructure upgrades.** While MCOS is measured based on the capability of the infrastructure added to the system rather than the load need that spurred the investment, utilities seek to "future proof" the utility grid by building new substations that have capability many multiples of the actual triggering load need. In its 2025 rate case, Con Edison proposed approximately **$12 billion in capital spending through 2034** to address forecasted load growth of roughly **590 MW**. Once financed and recovered from customers, this level of investment results in **annual ratepayer costs exceeding $1 billion over the life of the assets**, which typically remain in service for **30 to 50 years**.For example, Con Edison's 2025 rate case included capital spending for infrastructure of $12 billion through 2034 to meet an expected 590 MW load growth. In particular, the 17 distribution substation upgrades plan would provide capability of five times the forecasted 2034 load relief needs (see page 20 for further discussion). DERs allow for

better use of the existing power system; they can be right sized and added incrementally to the system over time to match load growth needs and changing use profiles. Importantly, this system-efficiency tool, available in nearly all other industries, has not been as commercially and cost-effectively scalable for the electric utility industry before now.

- **Enhancing electric distribution power system reliability** by providing dispatchable load relief during peak demand periods.
- **Helping meet the reliability shortfall needs of the transmission system.** The Commission has an active proceeding (25-E-0074) to address identified transmission reliability shortfalls in Con Edison's New York City (Zone J) service territory. VDER-based projects, particularly dispatchable battery energy storage (BESS), are already being built. Operations can be optimized to provide load relief at the identified times, which overlap to a large extent with peak demand on the distribution grid.
- **Enabling the maximization of renewable generation** added to the system through flexible load shifting and storage capabilities.
- **Reducing carbon emissions** by shifting loads to cleaner, less power-intensive times for the grid.
- **Allowing for the displacement of peaker plants** in compliance with the State goals under the Department of Environmental Conservation (DEC) Peaker Rule.
- **Providing meaningful benefits to Disadvantaged Communities (DACs)**, including directly reducing energy costs for low-income households through monthly utility bill credits and improved local air quality.

NineDot urges the Commission to act with expediency in updating utility MCOS value and DRV component of the VDER tariff. Updated pricing signals are needed to ensure that distributed energy resources can move forward in time to support New York City's identified reliability needs while also capturing benefits of the Federal Investment Tax Credit (ITC). DRV rates have remained unchanged since 2017, based on MCOS studies performed using 2012-2015 data; given this substantial timing lag, NineDot recommends that certain projects be eligible for a one-time option to lock in an updated DRV rate, including those that signed interconnection agreements after the release of MCOS studies on June 30, 2025, and projects that opt into the

LSRV Alt-2 proposal to meet transmission security and reliability needs (described below). Projects with signed interconnection agreements typically still face construction financing hurdles and an updated DRV will ensure that more projects progress to completion. Additionally, for market stability, we recommend that the Commission authorize maintaining them in effect until the end of 2030 or a minimum of three years from the adoption of updated DRV rates.

Comments on Staff's DRV/LSRV Proposal

NineDot appreciates the opportunity to provide the following comments on Staff's DRV and LSRV proposal. We agree with many of the elements introduced by Staff in their proposal, including the following:

- **DRV should be equal to MCOS.** NineDot agrees with Staff's position that DRV should be equal to MCOS rather than a "de-averaged" percentage of MCOS. The de-averaging of MCOS to derive DRV and LSRV is neither a rational nor equitable methodology and it has not been an effective locational pricing signal. As described in the proposal, *"Precisely because Staff proposes the DRV should be applicable everywhere in a utility's service area, Staff proposes that the DRV should be based on system-wide avoidable costs. Further, setting the DRV at the system-wide MCOS level would also place DRV-eligible resources on a more level playing field with energy efficiency programs, which are justified based on system-wide MCOS*."

- **The LSRV program should be materially enhanced to include additional operational requirements.** While DRV has driven a market for DERs in Con Edison's territory, Con Edison has shown a preference for other programs to provide locational relief, such as the Dynamic Load Management (DLM) and Non-Wires Solutions (NWS) programs given their higher requirements for dispatchability and performance. *"LSRV-compensated VDER resources may not result in a deferral and generally provide less distribution grid value than the dispatchable resources participating in DR programs and under NWA contracts."*[1] The LSRV zones have not been updated in Con Edison

[1] Case 15-E-0751, Joint Utilities DRV and LSRV Considerations (technical conference presentation), January 30, 2025

territory since 2017 and most of the original LSRV capacity of 87.7 MW[2] was diverted to other programs. Importantly, these other programs are opaque and administratively burdensome to scale, increasing costs for ratepayers.[3]

- **The modified LSRV program should incorporate the most effective components of these locational-based electric load relief programs, while simultaneously creating a program that can be efficiently and cost-effectively scaled as the dispatchable DER market matures.** The importance of scalability and operational simplicity can not be overstated. Programs that are administratively burdensome increase costs and significantly extend deployment timelines. According to the 6.0 GW Storage Roadmap, storage deployment in NYS is expected to reach 11.7 GW by 2040.[4]

- **The proposed substation aggregation method reflects a fair societal benefit-cost structure.** NineDot agrees with staff that it is appropriate to exclude substations with no planned upgrades from the calculation of the long-run marginal costs. As noted in the proposal, *"Staff's proposed method does depart from the earlier method in how it combines the costs for the various network segments of the distribution system (i.e., secondary, primary, substation, area station, transmission) when any of these segments have nonzero costs in a substation serving area."* Staff's updated method veered from the previous approach of summing each of the segments to derive MCOS by using a weighted sum of all projects across substations. NineDot agrees that this represents a fair balance between providing long-term, cost-based pricing signals to the market without overly compensating developers given that "very few, if any, substation areas are affected by proposed relief projects across all network segments."

- The proposed modified LSRV program with dynamic pricing signals and coupling charging behavior to export needs is a **meaningful step towards a fulsome**

[2] Con Edison Electric Tariff, PSC NO: 10-Electricity, Statement Of Value Of Distributed Energy Resources Value Stack Credits, 12/01/2017
[3] The contracting time for NWS projects often runs longer than a year.
[4] Case 18-E-0130, New York State Department of Public Service ("DPS") and NYSERDA, *New York's 6 GW Energy Storage Roadmap: Policy Options for Continued Growth in Energy Storage* (March 15, 2024) ("Energy Storage Roadmap").

Bidirectional Service Classification (SC), specific to a new form of energy consumers with completely flexible demand profiles. BESS projects strictly consume energy from the grid in order to be reliability resources at a later time, unlike at traditional consumers. A proposal for a Bidirectional SC was provided as part of NY-BEST's comment under the Grid of the Future proceeding (24-E-0165, 7/15/2025, Appendix A: "Designing a Bidirectional Electric Rate to Power New York's Grid of the Future: Today's Set of Tariff Kludges to a First-of-its-Kind, Integrated Bidirectional Service Classification (SC)").

NineDot also respectfully makes the following suggestions on the DRV framework and MCOS calculations for consideration.

- ***Extend the DRV value to reflect the useful life of the BESS.*** The DRV rate for a project coming onto the system should be fixed for as long as the project remains in service, similar to utility investments. This treatment is in line with that of traditional utility infrastructure investment, such as distribution and transmission substations, which are paid for by ratepayers over their useful life (in most cases 30-50 years). DERs that remain in service after the tenth year will continue to provide deferral value for infrastructure investments that may have been deferred in its first ten years of service, and it is appropriate that the DRV value reflects that value. This will provide cost certainty to enable more projects to be deployed, while also protecting ratepayers from the rapid inflation in utility infrastructure costs seen over the past decade. (Distribution plant construction costs have risen 7.2% per annum according to the Handy-Whitman Cost Trends of Electric Utility Construction for the North Atlantic Region from July 2015 to July 2024.[5]) At a minimum, the DRV rate should be fixed for 15 years to match similarly-designed utility programs, including the Buyback Exemption for standalone BESS, the Index Storage Credit (ISC) program[6], and the Con Edison Bulk Energy Storage Request for Proposal (RFP)[7].

[5] Whitman, Requardt & Associates, Handy-Whitman Bulletin No. 200: Cost Trends of Electric Utility Construction – North Atlantic Region (1973 = 100), Table E-1 (2016–2024)
[6] Based on the previous program data, the ISC contract term was selected as 15 years in "Order Establishing Updated Energy Storage Goal and Deployment Policy" (Case 18-E-0130, June 20, 2024).
[7] At the Joint Utilities' request, the competitive program term was extended from ten to fifteen years in "Order Directing Further Modifications To Energy Storage Solicitations" (Case 18-E-0130, March 16, 2023).

- ***Historical costs for substation and transmission projects should be included in the calculation of MCOS.*** Substation and transmission projects have long life spans with assets typically amortized over an extended period (30+ years). To the extent that a BESS can defer the building of these assets, the project costs should remain in the asset base used to calculate MCOS. In addition, including only projects that have yet to be built results in depressed MCOS values given that they include only partial values in the years leading up to the project coming online; this is significant given the length of time that it takes to bring a distribution or transmission substation online (6-8 years). Without including historical projects, MCOS will reflect a forward look at partial project costs for future grid infrastructure costs.

- NineDot has also laid out a proposal for a new framework for LSRV ("LSRV-Alt2") adders that provides locational pricing signals to optimize local distribution grid benefits and transmission system reliability needs, initially limited to dispatchable VDER resources in Con Edison territory[8]. NineDot agrees with Staff's position that de-averaging is no longer appropriate and LSRV compensation should reflect higher levels of service to the system. The LSRV proposals include a suite of modifications that can be easily implemented to address the issues that arise from the static nature of operations embedded in the current VDER pricing signals. The proposals seek to satisfy grid operator needs for additional operational requirements while preserving the bankable nature of the VDER tariff. NineDot intends this proposal will be a starting point for a broader conversation on the evolution of a scalable LSRV framework that allows for the optimization of the sizable queue of VDER resources for distribution and transmission security value while considering how dynamic charging can be directly tied to operations.

Comments on Con Edison's MCOS Study

NineDot has comprehensively reviewed the MCOS studies filed by the Joint Utilities and DPS Staff, with particular focus on Con Edison. While the MCOS Order laid out the principles that would ensure uniformity in the MCOS filings, NineDot observed that there continue to be

[8] As noted in its Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, And Related Matters, March 9, 2017, From the 2017 VDER Order, However, the Commission recognizes that symmetry across all of the utilities in all aspects of the distribution planning methods is not realistic, nor is it necessarily desirable.

important and material variations in the utilities' approaches to the MCOS filings made in June and July 2025. Below is a summary of findings and recommendations from this analysis, which are explained more fully in the body of this paper. These comments are also accompanied by an Excel workbook in which we recalculate Con Edison's MCOS to correct for data integrity and methodological errors embedded in the filing.

- NineDot recommends the following changes be made in the calculation of Con Edison's MCOS value:
    - ***Inclusion of Load Transfer Capital Costs Designed to Service New Load:*** Con Edison did not include $3 billion in capital costs related to load transfers from a constrained substation to another (often, new) substation to meet load growth needs (See pages 17 for further discussion)
    - ***Discounted Capacity Phase-In for Pre-In-Service Years:*** Con Edison's approach uses full as-built capability when a project is in its construction and pre-construction phases rather than discounting the pre-in-service megawatts, a more rational approach adopted by other utilities (See pages 14 for further discussion)
    - ***Correction of Substation Mislabeling:*** Four substations had two different names in Staff's workbook (See Appendix 5 for further discussion) leading to calculation errors
    - ***Corrected Weighted Average Cost of Capital (WACC) Discount Rate*:** It is common practice to use post-tax WACC, which represents the rate of return the utilities can earn over the service life of a plant addition. (See Appendix 4 for further discussion)

When these changes are incorporated, Con Edison's levelized MCOS is $365.97 per kilowatt-year, reflecting annual growth of 4.0% relative to the 2015 levelized MCOS value. This is reasonable and well below the annual inflation rate in distribution construction costs.[9]

[9] Distribution construction costs have grown at 7.2% per annum over the past nine years. See note on page 7 for further details.

- In our review of Con Edison's Marginal Cost of Service Study, we examined the underlying load-growth-driven system expansion capital projects using public exhibits from Con Edison's 2025 rate case. We systematically observed a substantial allocation for spare capacity embedded in planned projects, which on average was roughly four times the forecasted 2034 need. The Order recognized that utility investments will include spare capacity[10], and ordered the joint utilities to disclose and "fully explain" how spare capacity and reserves are reflected in the studies. The level of spare capacity was not explained in Con Edison's study nor was a discussion of the level of capacity needed to ensure system reliability.
- **While utilities often build significant spare capacity relative to the forecasted needs in order to "future proof" the system, the level of potential ratepayer savings from replacing that upgrade increases with DERs given that MCOS is measured as a function of built capability. We have provided an example in Appendix 1 which shows that replacing a traditional upgrade with dispatchable DERs results in ratepayer savings of more than 90%.** In addition, DERs can be added incrementally as need arises, more quickly, and with more locational targeting than traditional infrastructure.
- Considering this mismatch, NineDot recommends tracking an alternative MCOS ("$MCOS_{load\ growth}$") for the purposes of determining LSRV areas given the significant potential for ratepayer savings from deploying BESS with operational requirements to satisfy grid operation needs. While the Joint Utilities (JU) have calculated MCOS as the cost of an additional kilowatt per *built capacity*, we recommend that the additional kilowatt cost per *incremental load growth* should also be calculated. As defined in the 2024 MCOS Order, *"marginal costs are estimated as the expected change in cost resulting from a forecasted change in demand (or load).*" Given the considerable level of spare capacity relative to the forecasted need,[11] Con Edison's $MCOS_{load\ growth}$ is $1,812.70/kW-y.

[10] From the 2024 MCOS Order: "This is another issue that is significantly rendered moot by our choice of the NERA method for use by all the Joint Utilities. The amount of spare capacity and reserve margins to be reflected in the studies is significantly resolved as spare capacity headroom is considered by utilities' planning staffs in the sizing of the actual projects that will form the basis of the MCOS studies. However, the Joint Utilities shall fully explain how spare capacity and reserve margins are reflected in their NERA method MCOS studies."

[11] See Using Incremental Load Growth Rather than Capability with Spare Capacity on page 20 for further details

- LSRV areas would be determined by those that have $MCOS_{load\ growth}$ for distribution and transmission substation upgrades that are materially above the MCOS based on substation capacity given the ratepayer savings potential. Given that the utility will only propose a limited number of large substation and transmission projects with significant spare capacity at once, this is not incongruent with Staff's proposal that the LSRV area should capture ~10% of a company's service areas.[12] Con Edison has 63 area substations in its territory (and an additional six within its capital plan), so the two proposed in Staff's proposal fall well below that threshold[13] and also not solve the clustering problems highlighted by Con Edison in its Interconnection Constraints filing[14].

- ***Marginal cost of service studies should be audited and tiebacks to other project cost disclosures should be provided.*** NineDot strongly recommends that the utilities be required to provide more transparency for substation and transmission projects, including the load need driving the upgrade, an explanation of the spare capacity[15] and references to other project cost disclosures such as whitepapers included in rate cases or other public filings with explanations of any material deviations. Given the material omission noted in Con Edison's MCOS study of $3 billion in load transfers, we recommend that utility MCOS filings also be audited by an independent third party overseen by the DPS.

[12] Staff Proposal on DRV and LSRV, December 11, 2025, Case 15-E-0751, page 6
[13] Practically, the two identified LSRV substation areas (Gateway Park [$1.3 billion substation CapEx] and Nevins Street [$1.5 billion substation CapeEx]) are future planned projects with proposed in-service dates in 2028 and 2032. The load-growth areas with associated load transfers are the more-relevant current LSRV areas: Bensonhurst No. 2 (load transfer cost of $427 million) and Water Street (load transfer cost of $269 million).
[14] Case 25-E-0764, Proceeding on Motion of the Commission to Address New York City Reliability Needs, Con Edison Notice, January 14, 2026, page 2
[15] For example, the NYSEG and RG&E MCOS workpapers adjust the "Added Capacity (MW)" for each project at each segment by 10% to calculate the "Added Load Carrying Capability (MW)" used as the denominator in the Annual Unit Cost Calculation (in $/kW).

II. Historical Context of ConEd's MCOS Study

Background on 2015 MCOS Studies that Set Initial VDER Rates

Since 2017, the system-wide VDER DRV rate in Con Edison territory has been set to $199.40/kW-y[16]. This rate was calculated based on a "de-averaged" MCOS that excludes the estimated increased marginal costs in high-stress grid areas[17]. The MCOS used as an input to set the 2017 DRV rate was $226.00/kW-y. This is the single-year 2017 MCOS output from Con Edison's 2015 MCOS study[18] using the traditional NERA segment-aggregation method[19].

Applying a ten-year levelization to the 2015-2024 MCOS annual results, the annualized MCOS should have been $246.92/kW-y[20]. The 2015-2025 Gross Domestic Product (GDP) Implicit Price Deflator implies an escalator of 33.8%[21] or, equivalently, 3.0% per annum. Using a straight-forward approach of applying an inflation-adjustment to the 2015 Con Edison levelized MCOS to determine the 2025 MCOS, , the 2025 MCOS is estimated to be $330.38/kW-y.

2017 Con Edison Single-Year Segment-Aggregation MCOS	**$226.77**
2015 Con Edison Levelized Segment-Aggregation MCOS	**$246.92**
2025 Con Edison Segment-Aggregation MCOS (+3.0% per annum inflation adjustment)	**$330.38**

This is a helpful datapoint to evaluate reasonableness of the proposed MCOS levels, particularly in light of the higher level of inflation in utility upgrade costs.

[16] The equivalent per-kWh DRV rate is 85.360 cents/kWh for a VDER Phase 2 project's grid injections during 232-236 peak summer-period hours.
[17] High-stress areas (initially covering 19% of the Con Edison substation areas) are additionally compensated with the LSRV Adder of $140.76/kW-yr. The de-averaging formula is: DRV = (MCOS - 19% x 1.5 x MCOS) / (1-19%) where 1.5x is the estimated higher marginal cost for LSRV Zones (i.e., $339.00/kW).
[18] The single-year 2017 MCOS rate from the 2015 study was $226.77/kW-y, which was seemingly mistakenly "floored" to $226.00/kW-y.
[19] In 2015, Con Edison aggregated costs from seven Cost Center segments: Transmission Costs Excluding TCCs, Switching Station Costs – Transmission Functionality, Switching Station Costs – Substation Functionality, Area Substation and Substransmission Costs, System Weighted Primary Feeder Costs, System Weighted Transformer Costs, and System Weighted Secondary Cable Costs.
[20] This applies a discount rate of 6.82%, Con Edison's 2017 weighted-average cost of capital (after-tax). The error in using the *single-year* MCOS rather than the *levelized* MCOS means demand reduction from VDER resources has been undervalued by 9.3% since 2017.
[21] See Federal Reserve Economic Data (FRED) at https://fred.stlouisfed.org/series/GDPDEF.

Con Edison 2025 MCOS Study Results

In June and July 2025, Con Edison filed an updated MCOS study and Excel workpaper using the traditional NERA segment-aggregation method[22]. Applying a series of straightforward corrections to the Con Edison filing[23] and applying a ten-year levelization (discount rate set as the 2025 after-tax weighted average cost of capital [WACC] of 6.85%[24]), the 2025 MCOS result is $379.09/kW-y[25]. Over the ten-year period between 2015 and 2025, the implied compound annual growth rate is 4.4% ($246.92 to $379.09), which is consistent, as utility costs have risen faster than the 3.0% GDP-based inflation rate. As measured by the Handy-Whitman Cost Trends of Electric Utility Construction for the North Atlantic Region, distribution plant construction costs, for example, have grown at an annual rate of 7.2% over the nine years between July 2015 and July 2024.[26]

2015 Con Edison Segment-Aggregation MCOS	**$246.92**
2025 Con Edison Segment-Aggregation MCOS (implied +4.4% per annum growth rate)	**$379.09**

DPS 2025 MCOS Study Results

In December 2025, DPS filed a revised MCOS methodology and Excel workbook proposing a novel replacement for the traditional NERA segment-aggregation method. DPS proposed using a weighted average of substation levelized MCOS rates. With a series of straightforward corrections to the DPS filing[27] and applying the correct 6.85% discount rate, the 2025 weighted MCOS result is $270.03/kW-y[28].

[22] In 2025, Con Edison aggregated costs from five Cost Center segments: Transmission Costs, Area Station and Sub-Transmission Costs, Primary Feeder Costs, Transformer Costs, and Secondary Cable Costs.
[23] Corrections are: double application of inflation factor for Primary, Transformer, and Secondary Costs and reclassification of eight substations into their proper Region (i.e., borough or county).
[24] In DPS's workpaper, a discount rate of 8.42% was used which is an incorrect application of the pre-tax WACC. See Appendix 4 for an analysis of discount rates.
[25] Without making corrections, the 2025 Con Edison segment-aggregation MCOS is $392.03/kW-y.
[26] Whitman, Requardt & Associates, *Handy-Whitman Bulletin No. 200: Cost Trends of Electric Utility Construction – North Atlantic Region (1973 = 100),* Table E-1 (2016–2024), DocRefId {70EF1196-0000-CF15-8270-0D4A628F7281} posted on NYS DPS document repository.
[27] Four substations were mislabeled and their upgrades were excluded from the weighting formula. See Appendix 5 for a description of the corrections.
[28] DPS reported $252.54/kW-y, but this had the four substations mislabeled and applied the incorrect pre-tax WACC.

2025 DPS Weighted MCOS	$270.03

This result suggests that the MCOS used for setting VDER DRV rates has changed from $246.92 to $269.71 between 2015 and 2025. This implies an annual growth in value to the distribution grid of 0.9%, well below the rate of general inflation as well as that of distribution-grid spending.

III. Observations and recommendations from ConEd's 2025 MCOS Study analysis

Discounted Capacity Phase-In for Pre-In-Service Years

In Con Edison's MCOS filing, the utility estimates the marginal cost for each multi-year construction project *prior* to the in-service date.

As one example, the new Nevins Street area substation is scheduled to be in service date in 2032[29], with a total cost of $1.465 billion and capability of 358 megawatts. Construction will begin in 2026, with a first-year capital expense of $15 million. The all-in unit cost is $1.465 billion divided by 358 MW, or $4,092/kilowatt. In its MCOS study, Con Edison seeks to estimate the marginal cost of this substation project in years 2025-2031, seven years prior to when the substation is planned to serve any customer load and one year prior to commencing construction.

As an obvious practical matter, an incomplete substation does not serve any customer load. As an exercise, one could ask how many MWs of load a partially-completed substation can theoretically serve. For example, if a substation is 50% constructed, one could estimate that 50% of the capability is notionally "available" (in the case of Nevins Street, 179 MW). The cumulative costs expended may be a proxy for project competition (in the case of Nevins Street, $733 million in cumulative spending represents 50% of the project cost). This is a compelling and effective tool for "smoothing out" the lumpiness of infrastructure spending, a central goal of long-term marginal cost methods. It is particularly important to include the pre-in service

[29] The Nevins Street project is a part of a broader package of upgrades including the Brooklyn Clean Energy Hub (BCEH) transmission substation, the Gateway Park distribution substation (formerly called Gateway Park No. 1), the Atlantic distribution substation (formerly called Gateway Park No. 2), and load transfers from the existing Bensonhurst No. 2, Water Street, and Brownville No. 2 substation areas with a total cost of $5.9 billion from prior to 2025 to 2034.

projects given the lack of completed projects in the MCOS study and NineDot strongly agrees with the inclusion of these costs within the current MCOS framework[30]. However, there is no standard practice for calculating marginal costs prior to a project's in-service date.

Con Edison's pre-in-service accounting method is materially different from other utilities' MCOS filings[31]. Con Edison's method assumes that 100% of each project's MW capability is available each year *prior* to the operational date. For example, for the Nevins Street area substation project, Con Edison includes 358 MW of effective capability in each year prior to 2032, including in 2025 when there had not yet been any project spending nor construction progress.

Con Edison Nevins Street Area Substation Project Con Edison Accounting Method for Pre-In-Service "Available" MW Capability								
Year	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Cumulative Spending (M$)	0	15	90	190	415	865	1,240	1,465
Percent of Total Spend	0%	1%	6%	13%	28%	59%	100%	100%
"Available" MW	**358**	**358**	**358**	**358**	**358**	**358**	**358**	**358**
Percent of Total Capability	100%	100%	100%	100%	100%	100%	100%	100%
Marginal Cost ($/kW)	$0	$42	$251	$531	$1,159	$2,416	$3,464	$4,092

The annual marginal cost "steps up" the total $4,092/kW over the eight-year period. This method egregiously undercounts the marginal costs for pre-in-service years. The Con Edison method effectively implies that a miniscule portion of the project costs (0%-13% for 2025-2028) supports the servicing of load for 100% of the new project's technical capability (358 MW).

Other utilities apply a slightly more realistic method for the "available" capability in prior years. The "Available" MW are discounted each year prior by the utility's after-tax weighted average cost of capital, which is a proxy capturing construction progress over time while "smoothing out" lumpiness. One year prior to completion, a project's MWs are discounted by 6.85%; two years prior, the MWs are discounted by $(6.85\%)^2$, etc. For the Nevins Street example, in 2026, when 1% of the project costs are forecast to be expended, this method outputs that 65%, or 234 MW of the total 358 MW are "available."

[30] Under the current methodology, zero values before a project has begun depress the overall project net present value over a 10-year period. Another option would be to calculate an annual MCOS value that includes all in construction projects for each year and then take the net present value of the annual MCOS values.
[31] In their respective MCOS filings, NYSEG and RG&E used the WACC-discounting method described here. National Grid used an inflation-adjusted from the in-service-year MCOS for prior years.

Con Edison Nevins Street Area Substation Project NYSEG/RG&E WACC-Discounting Method for Pre-In-Service "Available" MW Capability								
Year	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Cumulative Spending (M$)	0	15	90	190	415	865	1,240	1,465
Percent of Total Spend	0%	1%	6%	13%	28%	59%	100%	100%
MW Discount Factor	0.61	0.65	0.70	0.75	0.81	0.87	0.93	1.00
"Available" MW	**218**	**234**	**251**	**270**	**289**	**311**	**333**	**358**
Percent of Total Capability	61%	65%	70%	75%	81%	87%	93%	100%
Marginal Cost ($/kW)	$0	$64	$358	$705	$1,434	$2,784	$3,718	$4,092

The WACC-based discounted MW method is also an underestimate of the hypothetical pre-in-service marginal cost and fails to correct the $0 cost prior to commencing construction. However, the method is directionally correct. For example, for 2025-2028 spending of 0%-13% of the total project costs, this method implies that the project can support the servicing of load for 61-75% of the new project's technical capability (218-270 MW) rather than the full 358 MW. The longer the construction period, the larger the discount on the pre-in-service available MW, which is the appropriate mathematical model.

Other potential accounting methods to set the MW Discount Factor in years prior to in-service date which we did not select include:

- percent of cumulative spending as a proxy,
- linear function that steps up annually in equal-sized steps (e.g., 25% per year for a four-year construction project or 12.5% per year for an eight-year construction project), and
- logistic function that increases with a "S-curve" shape, commonly used for tracking real-world construction project progress.

Applying the NYSEG/RG&E WACC-based discounted MW to the Con Edison Segment-Aggregation Method and the DPS Weighted MCOS Method provides the following results:

WACC-Discounted MW Method for Pre In-Service Years Discount Rate = 6.85%	
2025 DPS Weighted MCOS	**$284.74**
2025 Con Edison Segment-Aggregation MCOS	**$399.02**

Inclusion of Load-Growth Driven Transfer Capital Costs

To serve additional new load, a typical utility solution is to upgrade an existing substation (e.g., with an additional transformer bank) or to construct a new substation. In parallel with any new substation, a load transfer from an existing substation load area or multiple substation load areas is implemented. Substation upgrades are also often accompanied by a load transfer from another substation area. Some substations are designed to be upgradeable, and implementing that planned upgrade and the load transfer rather than upgrading within the load area experiencing load growth is determined to be the best solution.

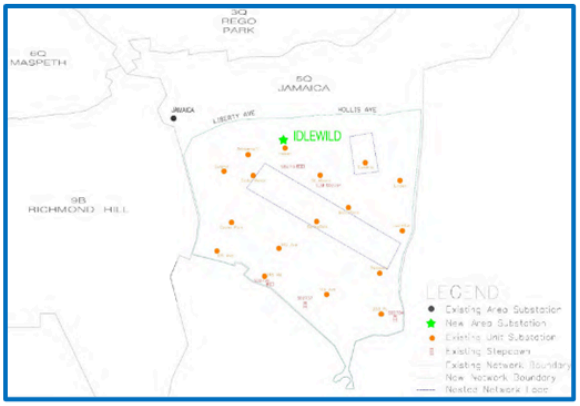
These types of load transfers are an essential capital cost in serving new incremental load. **However, in Con Edison's MCOS filing, load transfer costs are excluded from the substation capital expenditure reporting**, even though they are reported within"System Expansion and New Business Capital Expenditure" exhibits within the utility's 2025 Rate Case filings. Ten of Con Edison's planned substation upgrades are accompanied by load transfers, including for all six new substations[32]. **This represents 1,163 MW of load transfers with a capital budget of $2.976 billion that are not captured in the MCOS dataset.**

Con Edison Load Transfer Capital Projects			
New Substation Area	**From Substation(s)**	**CapEx (M$)**	**Transfer (MW)**
Idlewild	Jamaica	$264.3	170
Gateway Park	Bensonhurst No. 2	$426.6	130
Glendale	Brownsville No. 1	$119.0	60
Millwood West	Ossining West	$49.8	20
Cedar Street	Washington Street	$102.3	50
Nevins Street	Water Street	$268.9	149
Grasslands	White Plains, Elmsford No. 2	$154.8	84
Hillside	Corona No. 1	$860.0	178
Industry City	Greenwood	$240.1	80
Atlantic	Brownsville No. 2	$490.0	242
10 Substation Areas	**11 Substation Areas**	**$2,975.5**	**1,163 MW**

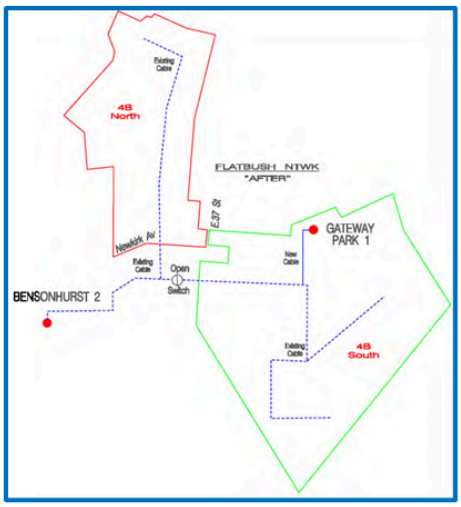
[32] Con Edison does include transmission-feeder load transfers (i.e., construction costs for new transmission feeders that serve area substation from transmission substations) but excludes distribution-feeder load transfers from the capital budget accounts. Transmission feeders costs are included for: Newtown (138-kV feeder from Vernon), Parkview (138-kV feeder from Mott Haven), Mott Haven (138-kV feeder from Mott Haven), Glendale (138-kV feeder from Vernon), Fox Hills (138-kV feeder from Fox Hills), Parkchester No 1 (138-kV feeder from East 179th Street), Millwood West (138-kV feeder from Millwood West), Cedar Street (138-kV feeder from Dunwoodie North), Nevins Street (four 138-kV feeders from Brooklyn Clean Energy Hub), Grasslands (138-kV feeder from Eastview), Hillside (138-kV feeder from Eastern Queens), and Atlantic (four 138-kV feeders from Gateway Park).

Maps of these load transfer projects are included below and the relevant Con Edison workpaper source documents from Major Rate Case 25-E-0072 are included as Appendix 10.

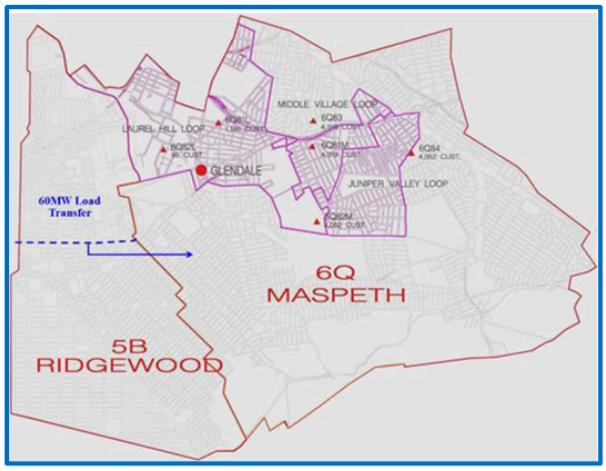
Con Edison Load Transfer Capital Projects



Jamaica to Idlewild Load Transfer



Bensonhurst No. 2 to Gateway Park Load Transfer

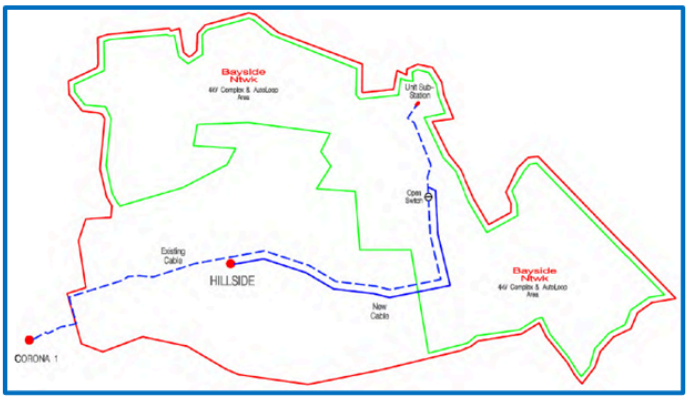


Brownsville No. 1 to Glendale Load Transfer

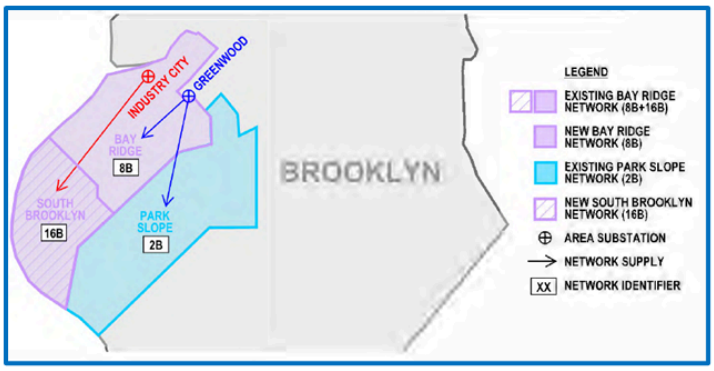


Water Street to Nevins Street Load Transfer

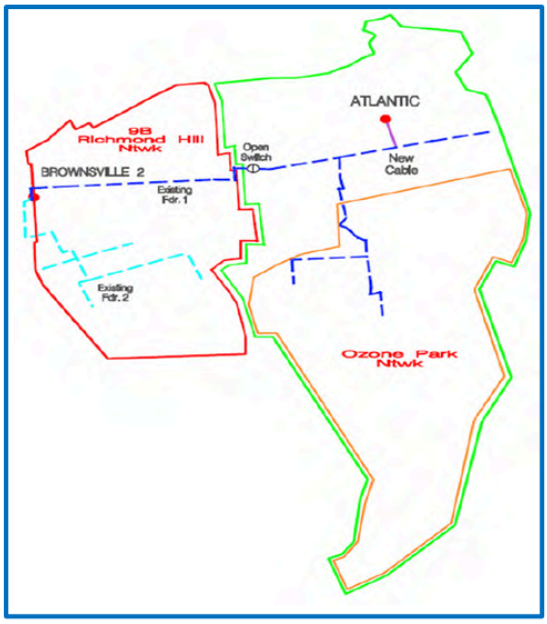
Con Edison Load Transfer Capital Projects (con't)



Corona No. 1 to Hillside Load Transfer



Greenwood to Industry City Load Transfer



Brownsville No. 2 to Atlantic Load Transfer

The load-growth-driven capital costs must be included as a component of associated substation upgrade projects, layered using the same ten-year cashflow schedule. With this inclusion of the load transfer capital expenses, the MCOS adjusts to:

WACC-Discounted MW Method for Pre-In-Service Years Inclusion of Load Transfer CapEx Discount Rate = 6.85%	
2025 DPS Weighted MCOS	**$365.97**
2025 Con Edison Segment-Aggregation MCOS	**$447.98**

Using Incremental Load Growth Served Rather than Built Capability with Spare Capacity

Marginal costs are defined as the expected change in cost resulting from a forecasted change in demand or load ("Load Growth"). If infrastructure upgrades are required to the local transmission or distribution power grid to serve forecasted Load Growth, the capital costs for the upgrades are divided by the load forecast to calculate the marginal cost (in units of $/kW). In some cases, the upgrade can be avoided or deferred with load relief provided by a strategically located distributed energy resource[33]. For example, a dispatchable battery energy storage system with an operating profile that reduces net load on the local distribution system during peak periods at a kW capacity equivalent to the Load Growth. In principle, DER load relief and forecasted Load Growth can be set to be equal and opposite: each 1 MW of new load will be directly offset by 1 MW of DER grid injections at peak times. With an average VDER project size of 4-5 MW, projects can be added incrementally to meet the forecasted load and transmission security needs.

In Con Edison's July 2025 MCOS filing, the utility reports the "Additional Capacity" (in megawatts) for each identified major capital project rather than projected Load Growth. The Additional Capacity is the increased technical capability of an area or a transmission substation

[33] "As almost any student of elementary economics will recall, marginal cost is the cost of producing one more unit; it can equally be envisaged as the cost that would have been saved by producing one less unit. Looked at the first way, it may be termed incremental cost—the added cost of (a small amount of) incremental output. Observed in the second way, it is synonymous with avoidable cost—the cost that would be saved by (slightly) reducing output." Alfred E. Kahn, *The Economics of Regulation: Volume 1 (Principles and Institutions)*, Chapter 3: Marginal Cost Pricing, The Central Economic Principle: Marginal Cost Pricing (1970).

at the local contingency standard due to the construction project rather than the forecasted Load Growth over a ten-year planning horizon.

It is generally accepted in economics[34] as well as the Staff whitepaper that "[m]arginal costs are estimated as the expected change in cost resulting from a *forecasted change in demand (or load)*" over a ten-year planning horizon. In the 2024 MCOS Order, the Commission also recognized that MCOS studies, in incorporating planned rather than hypothetical projects, would measure the cost of an additional unit of built capability: "This is another issue that is significantly rendered moot by our choice of the NERA method for use by all the Joint Utilities. The amount of spare capacity and reserve margins to be reflected in the studies is significantly resolved as spare capacity headroom is considered by utilities' planning staff in the sizing of the actual projects that will form the basis of the MCOS studies." [35] The Commission goes on to note that "the Joint Utilities shall fully explain how spare capacity and reserve margins are reflected in their NERA method MCOS studies." **In the case of Con Edison, there is remarkable spare capacity relative to load need, amounting to roughly four times the stated load need, which was not addressed in its MCOS study. Given the level of spare capacity in the system, this is a material omission.**

For example, according to the MCOS filing, the Parkchester No. 1 area substation serving the Southeast Bronx network area has a planned Additional Capacity of 76 MW by installing a new fifth 138/13-kV transformer bank and installing a new 138-kV feeder from the East 179th Street transmission substation. Construction will commence in 2026, the planned in-service year is 2029, and the total capital cost budget is $124.9 million, meaning the unit cost of the upgrade is $124.9 million divided by 76 MW or $1,643 per kilowatt. However, there is significant divergence between the ten-year load forecast and Con Edison's Capability additions. For example, for the Parkchester No. 1 example, the ten-year (2025-2034) load growth forecast is:

[34] See Appendix 3 for further discussion.
[35] Order Addressing Marginal Cost of Service Studies, August 18, 2024, Case 15-E-0751

Con Edison Parkchester No. 1 Area Substation Project										
Year	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Net Load	209	215	221	227	234	244	251	258	265	274
Capability	236	236	236	236	236	**312**	**312**	**312**	**312**	**312**
Upgrade	0	0	0	0	0	**+76**	0	0	0	0
New Load	**0**	**0**	**0**	**0**	**0**	**8**	**15**	**22**	**29**	**38**
Excess	27	21	15	9	2	68	61	54	47	38

Over the ten-year planning horizon, this upgrade is forecast to serve 38 MW of new load by 2034 and no new load until 2030. While the upgrade has technical potential to serve up to 76 MW in new load (by increasing the substation capability from 236 to 312 MW), any additional hypothetical load beyond 38 MW is not part of the 2025 MCOS ten-year planning cycle. The marginal cost of the incremental load is $124.9 million divided by 38 MW or $3,287 per kilowatt.

As with the Parkchester No. 1 area substation example, each distribution area substation project in Con Edison's ten-year long-range marginal cost (LRMC) planning horizon has a mismatch between the technical capability and the triggering incremental load growth.

Con Edison's ten-year MCOS planning horizon included ten area substation projects with current aggregated capability of 2.1 gigawatts and establishing five new area substations, outlined in the table below. Through 2034, Con Edison plans to spend $7.42 billion to upgrade or construct these substations to increase their capabilities by 3.0 GW to 5.1 GW. The average unit cost for the upgrades is $7.42 billion divided by 3.0 GW, or $2,471/kW[36]. These seven substations are forecasted to serve 590 MW of new customer load through 2034, but due to "future proofing," Con Edison **is planning to build technical capability approximately five times the load growth need with excess 2034 capacity of 2,413 MW**.

[36] This is the cost of the substation only and excludes load transfer and transmission substation capital costs, where appropriate.

Forecast Load Growth and Capacity Additions for Con Edison Substation Projects				
Substation Project	**Current Capability**	**Expanded Capability**	**Additional Capability**	**Load Growth** (Through 2034)
Newtown	244 MW	361 MW	117 MW	11 MW
Parkchester No. 2	169	250	81	7
Idlewild (new)	0	358	358	122
Gateway Park (new)	0	358	358	84
Parkview	174	259	85	23
Mott Haven	239	333	94	13
Glendale	390	517	127	32
Fox Hills	236	354	118	17
Parkchester No. 1	236	312	76	38
Millwood West	83	162	79	31
Cedar Street	168	253	85	37
Nevins Street (new)	0	358	358	26
Grasslands	165	247	82	55
Hillside (new)	0	358	358	29
Bruckner	missing from Con Edison Workpapers			
Industry City (new)	0	269	269	65
Atlantic (new)	0	358	358	0
17 Substation Projects	**2,104 MW**	**5,107 MW**	**3,003 MW**	**590 MW**

One method to incorporate the marginal cost measured in terms of the ten-year load growth forecast is to replace Additional Capability with Load Growth in the MCOS calculus[37]. For transmission substation projects (e.g., Eastern Queens Transmission Substation [EQTS] and Brooklyn Clean Energy Hub [BCEH]), the load growth forecast is determined by aggregating the forecasts for interconnecting distribution substations (e.g., for EQTS, Idlewild and Hillside, and for BCEH, Nevins Street, Gateway Park, and Atlantic). With this method, the updated MCOS results are:

WACC-Discounted MW Method for Pre-In-Service Years Inclusion of Load Transfer CapEx Capacity Based on New Load Served Discount Rate = 6.85%	
2025 DPS Weighted MCOS	**$1,812.70**
2025 Con Edison Segment-Aggregation MCOS	**$2,209.95**

The ratio between these results and using capacity based on technical capability is five-fold, reflecting the ratio between aggregated load served in 2034 and additional capability built.

In principle, the "avoidable cost"—the cost that would be saved by reducing required output from these substation upgrade projects via peak load modification from strategically-located distributed energy resource projects—is equal to this MCOS result of $1,812/kW. For example, if 29 MW of new load can be served in the area proposed by the new Hillside substation, then the $871 million cost to construct the 358 MW substation and $861 million cost to transfer 171 MW from the Corona No. 1 substation can be avoided. Similarly, if 13 MW of new load can be served in the Mott Haven substation area, then $47 million to construct 94 MW of added capability (with a new transformer bank and new transmission feeder) can be avoided.

Con Edison workpaper source documents from Major Rate Case 25-E-0072 for area substation and transmission substation projects, which include the load growth forecasts for each project, are included as Appendices 8-10.

[37] This method (incorporating WACC-discounting phase-in MWs for pre-in-service years) does not utilize the year-by-year forecast of load growth (e.g., the New Load line item in the Parkchester No. 1 project table above) or make corrections for no load served prior to construction commencement.

LSRV Calculations for Proposed MCOS Modifications

For reference, the following table presents the associated Locational Service Relief Value (LSRV) rates for each of the methods described above, applying the standard-deviation method proposed by DPS Staff.

Method	LSRV ($/kW-y)	% of DRV	Number of LSRV Zones
2017 Con Edison Segment-Aggregation	$140.76	71%	14
Uncorrected DPS Workbook	$52.69	21%	2 – Gateway Park Nevins Street
Corrected DPS Workbook	$55.67	21%	2 – Gateway Park Nevins Street
+ Discount Rate = 6.85%	$56.87	21%	2 – Gateway Park Nevins Street
+ WACC-Discounted MW Method	$60.34	21%	2 – Gateway Park Nevins Street
+ Inclusion of Load Transfer CapEx	$76.67	21%	1 – Gateway Park
+ Capacity Based on New Load Served	$8,288.88	357%	1 – Atlantic

Note that the proposed new LSRV rate is a marked reduction from the current value (a reduction of 63% from $140.76/kW-y to $52.69/kW-y) while also proposing new material non-price terms and conditions. The current form of LSRV Adder structure has not been successful at providing a locational price signal. The proposed reduction in compensation and increase in program requirements moves further from animating this market. The limited number of available LSRV Zones may not drive a sustainable DER market focused on providing location-based grid benefits.

The areas that are designated by this method are all future substation areas, so it is also not evident what the locational requirements would be. The three identified areas are sibling projects that are designed to connect to the same new transmission substation (Brooklyn Clean Energy Hub [BCEH]) and transfer load from multiple existing substation areas starting in 2028-2034. However, if net load can be successfully reduced in the existing load pockets, these capital projects could be delayed or abandoned providing significant long-term ratepayer savings.

Proposed LSRV Zone	In-Service Year	Existing Substation Area	Load Need (2034)	Substation Cost (M$)	Load Transfer Cost (M$)
BCEH	2028			$855.0	$0.0
Gateway Park	2028	Bensonhurst No. 2	84	$1,344.1	$426.6
Nevins Street	2032	Water Street	26	$1,465.0	$268.9
Atlantic	2034	Brownsville No. 2	0	$1,050.0	$490.0
3 Zones			**110**	**$4,714.1**	**$1,185.5**

In principle, 110 MW of locationally-targeted and operationally-reliable DER projects within the existing Bensonhurst No. 2, Water Street, and Brownsville No. 2 substation areas can avoid or defer $5.9 billion in traditional transmission and distribution infrastructure upgrade costs.

This analysis demonstrates the potential cost-effectiveness of a well-designed LSRV pricing signal and program as a key component of the VDER Value Stack. Below, NineDot outlines a proposal to better operationalize LSRV

Overview of Companion MCOS Excel Workbook

The methods described and results presented are being simultaneously filed as part of a companion Microsoft Excel workbook with file name "Workpaper for CE 2025 MCOS Study - DPS Staff Proposal - NineDot.xlsx." This section is an overview of the Excel spreadsheet.

The starting point for drafting the workbook is Con Edison's July 2025 MCOS workbook filing titled "Workpaper for CE 2025 MCOS Study.xlsx." Each modification to the entries and formulas is described within a new worksheet tab titled "Change Log." A total of 3,838 individual modifications were made to: layer on the DPS Staff weighted MCOS methodology, include source data from Con Edison Rate Case filings, make straightforward corrections to inflation calculations and substation area regional classifications, and calculate MCOS using the alternative methods described above.

The workbook appended to or materially modified from Con Edison's initial filing are:

- **Staff MCOS**: a copy of the Con Edison worksheet tab from DPS's MCOS spreadsheet
- **Staff MCOS - Corrected**: corrections as described in Appendices 4 and 5
- **Total**: replicates DPS's weighted MCOS and standard-deviation LSRV proposal

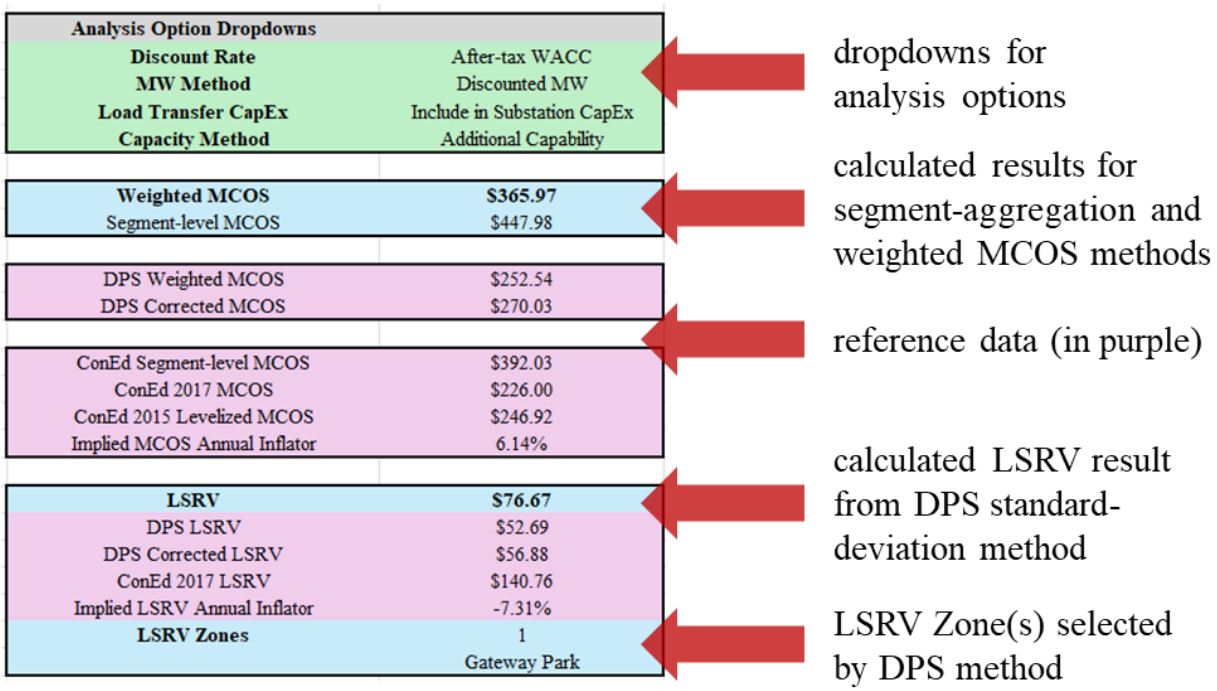
- **Primary, Secondary, Transmission**: fixed double counting of inflation
- **CapEx Transmission, CapEx Substation**: includes WACC-discounting method for pre-in-service years, load transfer costs, capacity based on load served
- **CapEx Distribution**: corrections for multiple regional classifications
- **CapEx Load Transfers**: source data for associated substation load transfers, drawn from Rate Case workpapers provided in Appendix 10
- **New Loads Served By Year**: source data for Net Loads and New Load Served for substation upgrade projects, drawn from Rate Case workpapers provided in Appendix 8
- **System Weighted Marginal Costs**: provides annualization/levelization calculation from segment-aggregation method
- **ConEd System Weighted MC**: provides annualization/levelization calculation from segment-aggregation method from Con Edison's initial filing without corrections for inflation formulas or substation misclassification
- **ConEd - MCOS – 2015**: for reference, the segment-aggregation method from Con Edison's 2015 MCOS study used to set the 2017 MCOS/DRV/LSRV rates
- **Segment Level Regional MC**: fixed double counting of inflation
- **Substation List**: list of substation areas and associated region ("B" for Brooklyn, "M" for Manhattan[38], "Q" for Queens, "SI" for Staten Island, "X" for Bronx, and "W" for Westchester)

The key MCOS and LSRV results are provided on the "Cover" page. The workbook user can select from four dropdown menus to enable or disable analysis options**:**

- **Discount Rate**: toggles between 6.85% for after-tax WACC and 8.42% pre-tax WACC, used in DPS's workpaper, as described in Appendix 4.
- **MW Method**: toggles between Con Edison's method of no phase-in for construction project progress and NYSEG/RG&E's method of applying a WACC-based discount rate to MWs for pre-in-service years

[38] In Con Edison's MCOS filing, Manhattan was incorrectly spelled "Manhatten" in twenty locations. While not material to the mathematical results, this noteworthy flaw combined with the erroneous formula for propagating annual inflation in 2,025 locations within the Excel file suggests a critical lack of data and calculation integrity. These small details and inconsistency issues provide helpful context for other more significant data and calculation errors, such as excluding associated load transfer costs, excluding a "phase-in" for project construction progress, and excluding levelization/annualization formulas.

- **Load Transfer CapEx**: toggles between Con Edison's method of excluding associated load transfer costs in substation upgrade projects and including the costs
- **Capacity Method**: toggles between using technical build capability for each transmission and area substation project and new load served (through 2034)



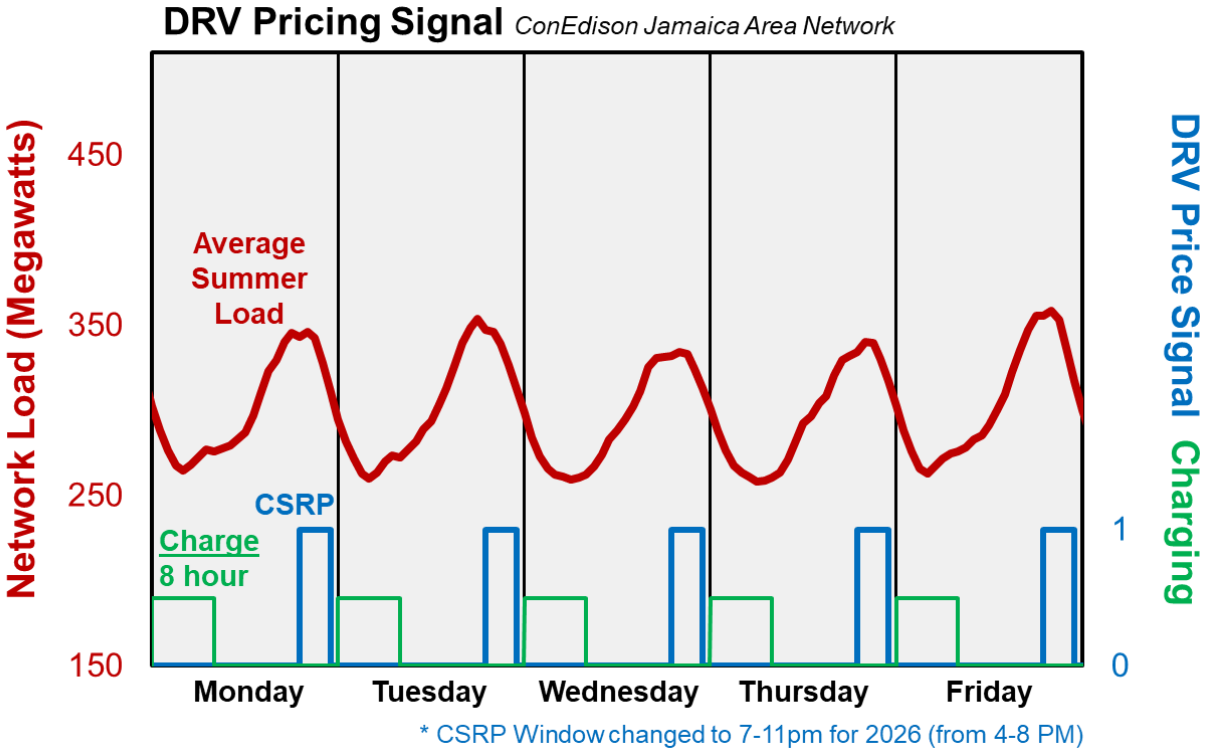
Analysis Option Dropdowns	
Discount Rate	After-tax WACC
MW Method	Discounted MW
Load Transfer CapEx	Include in Substation CapEx
Capacity Method	Additional Capability
Weighted MCOS	**$365.97**
Segment-level MCOS	$447.98
DPS Weighted MCOS	$252.54
DPS Corrected MCOS	$270.03
ConEd Segment-level MCOS	$392.03
ConEd 2017 MCOS	$226.00
ConEd 2015 Levelized MCOS	$246.92
Implied MCOS Annual Inflator	6.14%
LSRV	**$76.67**
DPS LSRV	$52.69
DPS Corrected LSRV	$56.88
ConEd 2017 LSRV	$140.76
Implied LSRV Annual Inflator	-7.31%
LSRV Zones	1
	Gateway Park

IV. NineDot Proposal for a Modified Locational Service Relief Value (LSRV) Pricing Signal: Optimizing Local Grid Benefits and Transmission Reliability Needs

The rate design for the current Value of Distributed Energy Resources (VDER) Value Stack Demand Reduction Value (DRV) – Phase 2 component has been the foundation for a robust development pipeline of retail front-of-the-meter (FTM) battery energy storage system (BESS) projects in Con Edison's Downstate New York service territory. The DRV-Phase 2 rate design features:

- **Contracted revenue** set early in the project development cycle: the initial DRV rate for a project set when a project executes an interconnection agreement upon payment of the 25% interconnection upgrade deposit.
- **Bankable ten-year rate lock**: the initial DRV rate is in place for ten summer periods commencing at project completion.
- **Well-defined operating profile**: all grid injections during a preset locationally-variant four-hour window during non-holiday weekdays during summer periods earn compensation at the preset DRV rate.

The motivation for this DRV structure is to balance the needs for financeable BESS projects and to provide quantifiable, tangible, and cost-based benefits to the local distribution grid. The main benefit is reducing localized demand during non-coincident network-area peaks allowing for the avoidance or deferral of the costs for traditional grid infrastructure upgrades that would otherwise be required for load growth. In principle, VDER-based BESS acts as a counterweight to new load, by exporting power to the grid simultaneously to when new customers are consuming the most power. It is implicit in this structure that the appropriate DRV compensation rate is equal to the MCOS rate. The DRV-Phase 2 design is an appropriate pricing signal for when dispatchable distributed energy resources such as BESS have a low to moderate penetration on the power grid. The resources, on average, provide load relief during both typical and high-need days in a consistent and predictable fashion by shifting load to low demand periods.



This plot demonstrates the grid benefits of DRV operations for an average week during the summer period in one of Con Edison's most overburdened network areas (the Jamaica area substation serving Queens, New York City). The DRV pricing signal properly motivates load relief during the 7-11pm peak window for each summer weekday. On average, the **DRV exports** reduce the **summer demand curve**[39] and the **associated charging loading** has little to no impact on offpeak demand.

As the development pipeline has matured beyond early mover and early majority adoption within Con Edison territory, signs of potential shortcomings of the DRV-Phase 2 rate design on the future grid have emerged.[40] The aggregated operating profile of VDER BESS projects has the potential to become a material load modifier to summer-period load curves on some network areas. Shortcoming of the current rate design include:

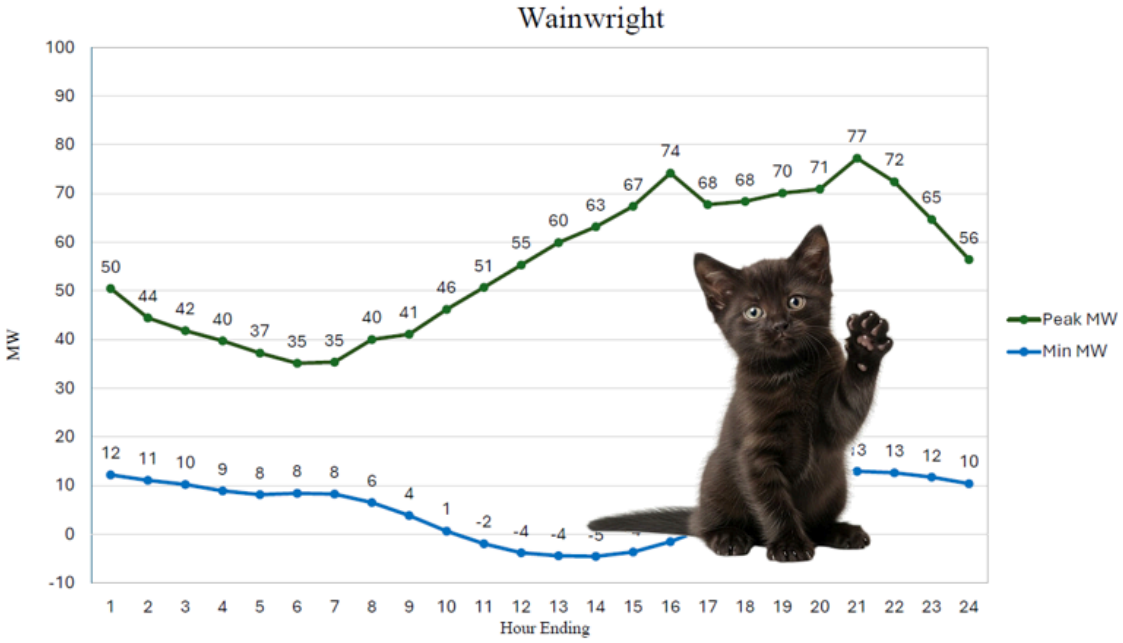
- Static pricing signals **do not provide temporal differentiation** between highest-need hours, high-need hours, and moderate-need hours during peak periods.

[39] Data simulated from Forecasted Network Level 8,760 Data available on Con Edison's Hosting Capacity Map.
[40] The issues have emerged in scenarios where all interconnection requests materialize, which is an unlikely scenario given historical trends. Approximately two-thirds of historical interconnection requests for BESS in Con Edison territory have later been withdrawn.

- Daily export windows and utility engineering decisions have required BESS operators **to charge on a static import window**, even as local grid conditions have the potential to become burdened during these predefined import windows[41].
- **Four-hour export windows are fixed for ten years**, even as local load curves shift or peak periods are widened.
- Exports are **limited to summer periods** for twenty-five years, even as the New York State grid shifts to a winter peaking system over the next decade.
- There is **no dynamic prioritization of grid benefits** between local network-area load relief, zonal-level reliability and transmission security needs, and NYCA-level avoided capacity costs.

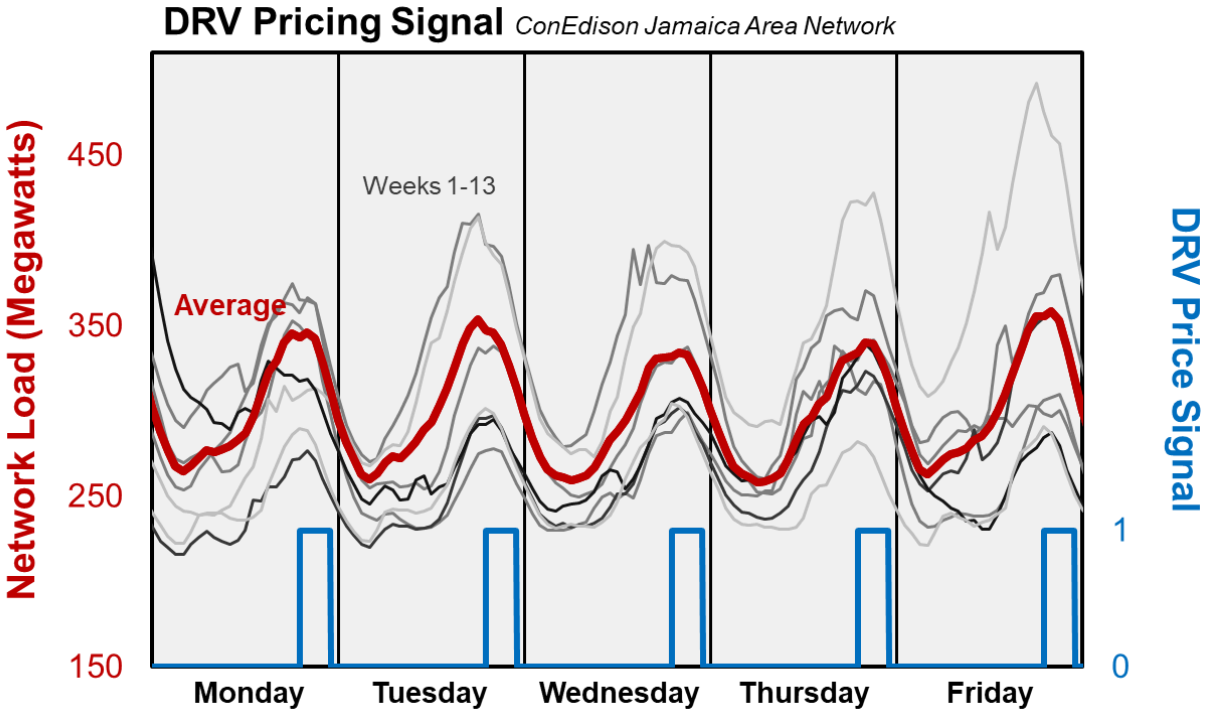
Due to the static daily-cycling profile for the current DRV use case for proposed VDER BESS projects, Con Edison has recently communicated that some network areas may become "saturated" with new offpeak demand. Con Edison has proposed building new "upstream" infrastructure to support BESS projects without modification to the existing DRV use case. The static nature of the DRV rate design is already evident in some Con Edison network area peak load curves. For networks with penetration of dispatchable BESS projects, the four-hour load relief is evident, leading to dual peaks in the hour prior to and the hour following the DRV window. This dynamic has been termed the "Kitten Curve."

[41] In practice, distribution-connected BESS are automatically "tripped" offline under a contingency event at the local feeder or an upstream level meaning that BESS cannot, in reality, be a "burden" to any grid infrastructure.



"The Kitten Curve": Static BESS exports from 4-8pm (Hour Ending 17-21) cause a dual-peak load curve (HE16 and HE22). With event-specific export windows, wider peaks can be managed.

For the Jamaica network area example, the lack of temporal differentiation is evident when the average summer 2025 demand curve is plotted in parallel with each summer week's demand curve (plotted in shades of gray). The spread between the peak-of-the-peak week and a moderate-demand week is over 150 MW.



Here, we describe a suite of easily-implementable modifications to launch a new opt-in "Locational Service Relief Value – Alternative 2" (LSRV-Alt2), initially limited to dispatchable VDER resources in the Con Edison service territory including standalone BESS facilities[42]. The goal is to fix the identified shortcomings while balancing grid benefits and bankability. LSRV-Alt2 pricing signal is designed to work in concert with Value Stack DRV and Capacity (ICAP) components and implementation of Con Edison's proposed Standby Service with Locational Variant Daily As-Used Demand Pricing[43] to achieve a more robust, reliable, and cost-effective local- and zonal-level power system.

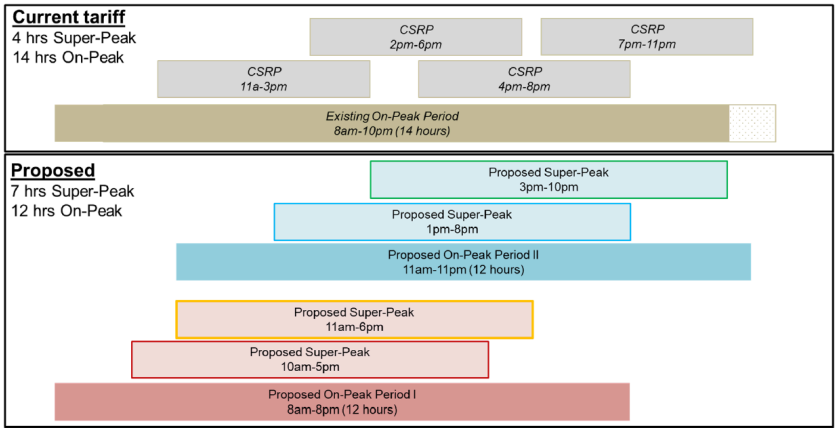
[42] This proposal is to initially launch LSRV-Alt2 in Con Edison territory, especially to meet forecasted transmission security and reliability needs, and to expand to other service territories, including LIPA/PSEGLI after evaluation, measurement, and verification of the program based on a pre-defined method.
[43] "Updated Rider Q, Standby Rate Pilot, Compliance Filing of Consolidated Edison Company of New York, Inc." (October 18, 2024), Case 18-E-0130.

Locational Service Relief Value – Alternative 2 (LSRV-Alt2) Definitions

Locational Service Relief Value – Alternative 2 (LSRV-Alt2) Definitions	
DRV Period	Remains unchanged Non-holiday weekdays June 24 to September 15 (excludes July 4 and Labor Day)
LSRV Period	**Summer Period** May through September, including holidays and weekends **Winter Period**[44] January through February, non-holiday weekdays
LSRV Capacity	A project-specific kWh that opts into providing grid injections during LSRV Events, which may be independently selected by operating periods: LSRV Period 1-5, 6-10, and 11-15[45].
LSRV Events	Days during the LSRV Period: **LSRV – Distribution Reliability (LSRV-DR)**: a day with anticipated higher reliability requirements at the local distribution network or sub-transmission substation level (under a similar definition of existing Rider AC Dynamic Load Management or Rider T demand-response programs) **LSRV – Transmission Security (LSRV-TS)**: a day with anticipated transmission security/reliability requirement at the zonal level (e.g., based on Con Edison's Clean & Non-Emitting Reliability Solutions to Manage Zone J Reliability Needs Request for Information) **LSRV – Grid Constraint (LSRV-GC)**: a day with anticipated local contingency issues at the local distribution network or substation level requiring limitations on localized charging loads

[44] By the mid-2030s, it's anticipated that Con Edison territory will be a winter peaking system, and LSRV resources should be "future proofed." January through February is currently the most-likely period for dual-fire generators to highly polluting burn fuel oil (located within so-called "Asthma Alleys"). As precedence, NYSEG has already established VDER compensation for grid injections during January 1-31 Hour Beginning 5:00 PM to Hour Beginning 6:00 PM.

[45] For example, a project may select 18,000 kWh for Years 1-5, 16,000 kWh for Years 6-10, and 14,000 kWh for Years 11-15, similar to how annual load-relief contracts under Non-Wires Solution programs are designed. This allows utility grid planners to design for and plan for real-world performance degradation rather than strictly beginning-of-life and end-of-life ratings.

LSRV Notification	**Day Ahead Notification** - A 21-hour prior notice, sent in a machine-readable OpenADR format, that provides information about an upcoming LSRV Event including LSRV Multiplier, Charging De-Rate Multiplier, and LSRV Event Window for any form of LSRV Event **Day Of Notification** - A 4-hour prior notification for a LSRV-DR or LSRV-TS Event
Normal Use	Any day during the DRV Period without an LSRV Event
DRV Window	Project-specific 4-hour window overlapping with the Superpeak Window
CSRP Window	Local network-specific 4-hour window (11am-3pm, 2pm-6pm, 4pm-8pm, or 7pm-11pm)
Superpeak Window	Local network-specific 7-hour window based on Locational Variant Daily As-Used Demand Pricing[46] (10am-5pm, 11am-6pm, 1pm-8pm, or 3pm-10pm) 
LSRV Event Window	Project-specific 4-, 5-, 6-, or 7-hour overlapping with Superpeak Window for LSRV-DR Events or Annual Transmission Reliability window for LSRV-TS Events that applies to a specific LSRV Event

[46] See Appendix 7 for Con Edison's proposed Locational Variant Daily As-Used Demand Pricing that should be adopted (with modification) in parallel with LSRV-Alt2.

<table>
<tr>
<td>Annual Transmission Reliability Window (cont'd)</td>
<td>
<table>
<tr><th></th><th>2032</th><th>2033</th><th>2034</th><th>2035</th><th>2036</th></tr>
<tr><td>Reliability Need (MW)</td><td>125</td><td>275</td><td>400</td><td>600</td><td>750</td></tr>
<tr><td>Hours Needed During Peak</td><td>3</td><td>4</td><td>5</td><td>6</td><td>9</td></tr>
<tr><td>Peak Day Duration</td><td>-
-
-
15:00-16:00
16:00-17:00
17:00-18:00
-
-
-</td><td>-
-
14:00-15:00
15:00-16:00
16:00-17:00
17:00-18:00
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14:00-15:00
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13:00-14:00
14:00-15:00
15:00-16:00
16:00-17:00
17:00-18:00
18:00-19:00
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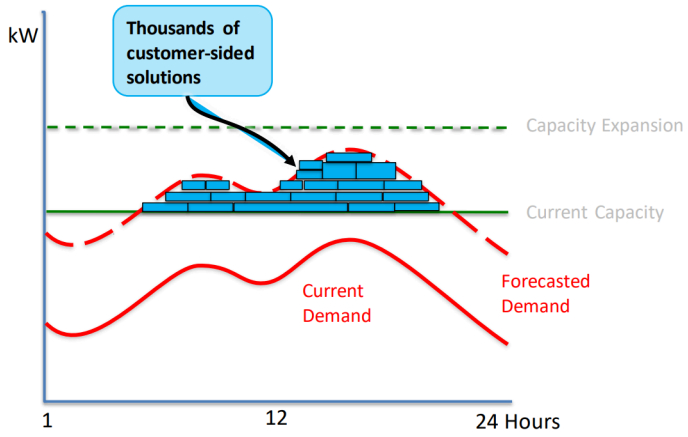
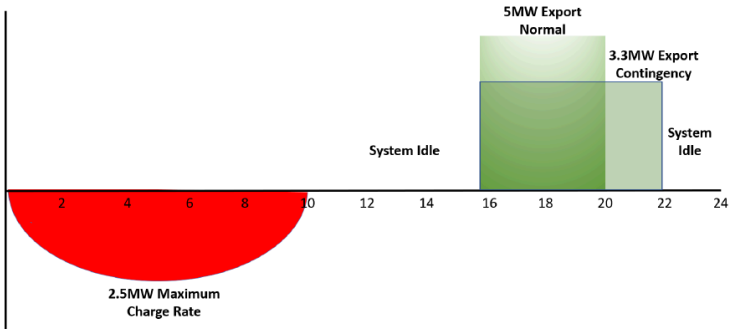
-</td><td>12:00-13:00
13:00-14:00
14:00-15:00
15:00-16:00
16:00-17:00
17:00-18:00
18:00-19:00
19:00-20:00
20:00-21:00</td></tr>
<tr><td>~MWh by Hour</td><td>-
-
-
15:00-16:00: 125
16:00-17:00: 25
17:00-18:00: 50
-
-
-</td><td>-
-
14:00-15:00: 100
15:00-16:00: 275
16:00-17:00: 175
17:00-18:00: 225
-
-
-</td><td>-
-
14:00-15:00: 200
15:00-16:00: 400
16:00-17:00: 300
17:00-18:00: 375
18:00-19:00: 150
-
-</td><td>-
13:00-14:00: 175
14:00-15:00: 375
15:00-16:00: 600
16:00-17:00: 525
17:00-18:00: 575
18:00-19:00: 350
-
-</td><td>12:00-13:00: 75
13:00-14:00: 300
14:00-15:00: 525
15:00-16:00: 750
16:00-17:00: 675
17:00-18:00: 750
18:00-19:00: 500
19:00-20:00: 150
20:00-21:00: 50</td></tr>
<tr><td>~ Total MWH</td><td>200</td><td>775</td><td>1,425</td><td>2,600</td><td>3,775</td></tr>
</table>
Annual Transmission Reliability Window for 2032-2036 range from 12:00pm-11:00pm
</td>
</tr>
<tr>
<td>Offpeak Window</td>
<td>Local network-specific 12-hour window based on Locational Variant Daily As-Used Demand Pricing
(8pm-8am or 11pm-11am)</td>
</tr>
<tr>
<td>DRV Rate</td>
<td>Fixed $/kWh rate, equivalent to systemwide MCOS $/kW-y rate

Set as MCOS $/kW-y rate divided by number of days in DRV Period (typically 58 or 59 days) times the 4 hours of performance per day (232-236 hours per DRV Period)

For example:
MCOS = $365.97/kW-y
DRV = $1.58/kWh</td>
</tr>
</table>

LSRV Adder Rate **LSRV Adder Rate (con't)**	**Per-Event** $/kWh rate Base LSRV Adder set to reflect a 25% adder to base DRV rate, based on a minimum 10 LSRV Events per year For example: MCOS = $365.97/kW-y DRV = $1.58/kWh LSRV Adder = $91.49/kW-y = $9.15/kW-Event[47] Based on a 4-hour LSRV Event = $1.58 + $2.29 = **$3.87/kWh** This is the **LSRV $/kWh rate that will be applied for 4-, 5-, 6-, or 7-hour LSRV Events**.  **Example Con Edison "stacked" portfolio**
Charge Curve	Project-specific hourly-variant kW charging curve that allows BESS project to get from 0% to 100% State of Charge within 8, 9, 10, 11, or 12 hours during Offpeak Window

[47] For reference, the current LSRV rate of $140.76/kW corresponds to $14.076/kW-Event or $3.52/kWh. Current LSRV Events are coincident with and additive to DRV export windows, meaning the grid-export value during LSRV Events is $4.37/kWh or 13% higher than this LSRV-Alt2 proposal. However, current LSRV windows are static, capped at 4-hour duration, have no relationship to charging-load profiles, no carve-out for transmission-security events, and no underperformance penalties.



Time	Charge Rate (kW)
12am-1am	1575
1am-2am	1675
2am-3am	1875
3am-4am	2375
4am-5am	2500
5m-6am	2500
6am-7am	2375
7am-8am	1875
8am-9am	1675
9am-10am	1575
Total Capacity (kWh)	**20000**

Example Charge Curve for 20 MWh battery
Source: Con Edison B-380 interconnection spec
See Appendix 6

Charging De-Rate LSRV Multiplier

Charging De-Rate LSRV Multiplier (con't)

A multiplier to the Charge Curve that may be effective during a Grid Constraint Event

LSRV-GC Events			
Charging De-Rate Multiplier	75%	50%	25%
LSRV Multiplier	1.50x	2.00x	4.00x

For Grid Constraint Events (which may overlap with Distribution Reliability or Transmission Security Events), the Charging De-Rate LSRV Multiplier is applied to the LSRV Adder Rate.

For example, for 75% charging de-rate (meaning that the Charge Curve is reduced by 25% of the standard curve), the Event-specific LSRV Rate is multiplied by 1.50x, or 1.50 x $3.87/kWh = **$5.81/kWh.**
This LSRV pricing signal explicitly motivates project operators to "hold" dispatchable energy prior to periods of both high need and potential charging constraints while balancing grid operators responsibility to judicially call charging reduction events.

Effective Contract Demand	Average kW rate of the Charge Curve (used for Standby Service Contract Demand pricing in lieu of the peak demand of Charge Curve)
LSRV Performance Factor	Total grid injections during LSRV Events (measuring in kWh) divided by [LSRV Capacity multiplied by the number of LSRV Events]
LSRV Adjusted Performance Factor	If the LSRV Performance Factor during all LSRV Events is less than 80%, then LSRV compensation is reduced by 2% for every 1% less than 80% (with a compensation floor of 0%).

LSRV-Alt2 Compensation Rate Design, Terms, and Conditions

1. At the 25% interconnection upgrade payment, or when opting into LSRV-Alt2, a project is designated: DRV Rate, DRV Window initially set as the CSRP Window, Superpeak Window, Offpeak Window, and Charge Curve[48]. The project is required to also take Standby Service with Locational Variant Daily As-Used Demand Pricing. The interconnection customer selects its project-specific LSRV Capacity to participate within LSRV Events in three buckets: years 1 to 5, years 6 to 10, and years 11 to 15.
2. On or before April 1 each year after achieving Permission to Operate, Con Edison may select any Charge Curve, i.e., each project's charging window and load profile may change from year to year.
3. During Normal Use, all grid injections during the DRV Window are compensated at the DRV Rate.
4. Con Edison may call up to 15 LSRV Events per LSRV Period with an LSRV Notification. For an LSRV Event, the discharging and charging pricing signals are modified from Notice Use.
    a. During an Day-Ahead LSRV Event, Con Edison may restrict charging to 25%, 50%, or 75% of Charge Curve. A Charging De-rate Multiplier applied to the Charge Curve during the Offpeak Period. For example, if a LSRV Event is July

[48] The use of a curved charging shape that meets the locational and temporal needs of the grid is already an established engineering standard incorporated into Con Edison's Distribution Engineering Bulletin for B-380 BESS interconnections titled "Underground Network Two Feeder Two Transformer service for the installation of 5000 kW of DER with contingency curtailment to 3330 kW of export", Revision 0, 12/01/2022. See Appendix 6 for an excerpted text.

15, and the prior Offpeak Period is July 15, 12am-9am, then Con Edison sends LSRV Notification by July 14 at 3am.

b. Con Edison may set a project-specific and Event-specific LSRV Event Window[49] (which may be 4, 5, 6, or 7 hours in duration and does not need to match the DRV Window). At least 4 hours in advance of a project's Superpeak Window, Con Edison may modify the LSRV Event Window with a LSRV Notification.

c. During the LSRV Event Window, all grid injections are compensated at the per-Event LSRV Adder Rate, as adjusted by LSRV Multiplier (applicable for LSRV-GS Events).

5. LSRV compensation for performance during LSRV Events is calculated by November 1 after the LSRV Period, rather than as part of the monthly billing cycles (e.g,, May, June, July, August, September). The compensation is provided in twelve equal increments during the following calendar year, except for projects operating as part of the Statewide Solar for All (SSFA) low-income assistance program which each receive compensation as a lump-sum in the November billing cycle.

   a. If the LSRV Performance Factor during all LSRV Events is less than 80%, then LSRV compensation is reduced by 2% for every 1% less than 80% (with a compensation floor of 0%).

   b. If the LSRV Adjusted Performance Factor is 0% for two consecutive summer seasons, then the project's LSRV Multiplier Rate is fixed at 1.00x for all LSRV Events for the subsequent summer season. If the LSRV Adjusted Performance Factor is >50% for the subsequent summer, the typical LSRV Multiplier Rate is reinstated for the following summer.

   c. If there are fewer than ten LSRV Events, uncalled Events are treated as 100% performance.

6. Any project may make a one-time irrevocable decision to opt into LSRV-Alt2 program, including operating projects or projects that have executed interconnection agreements.

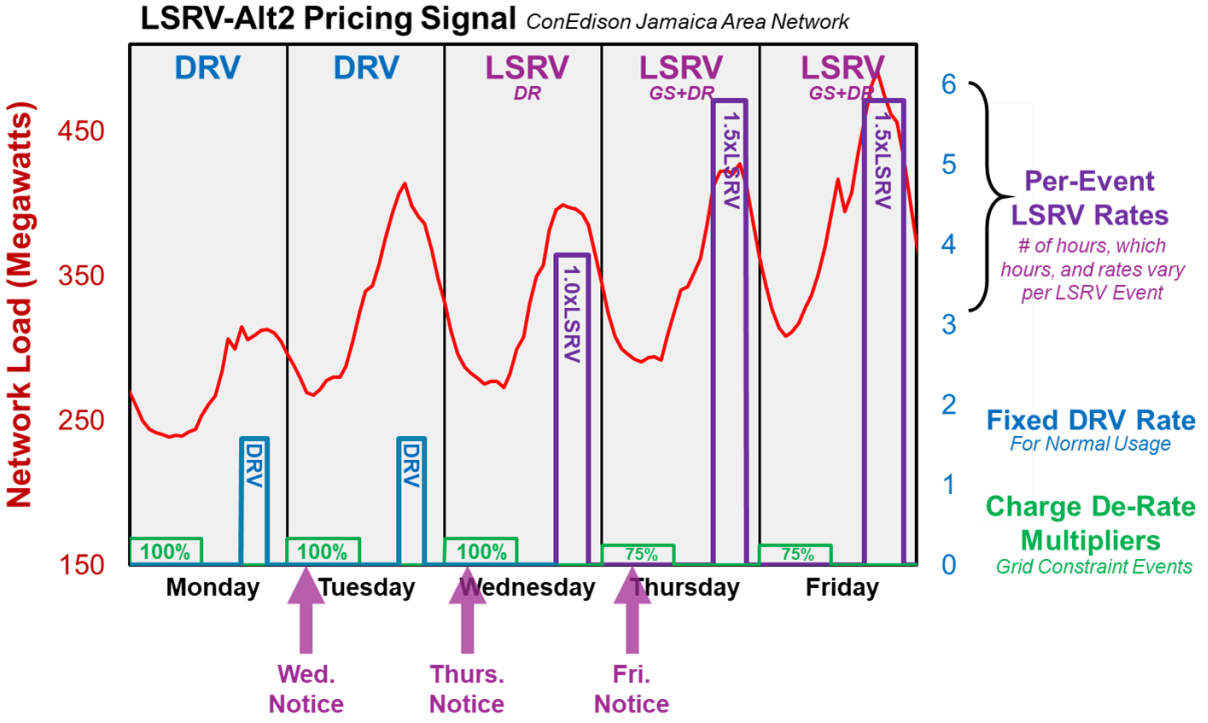
[49] As LSRV compensation is based on kWh injections, BESS developers are agnostic to the duration changes. For example, project-specific LSRV Event Windows are designed to smooth out load relief in network areas with wider peaks, rather than creating a dual-peaking load curve prior to and after BESS projects provide load relief. The current fixed four-hour DRV period (set based on local CSRP windows in effect upon executing an interconnection agreement) are causing this dual-peak scenario in multiple network areas. Alternatively, an aggregation of project-specific LSRV Events across Zone J can be optimized to meet transmission security and reliably needs.

For those projects, the DRV Rate will be amended to the then-applicable DRV Rate and set for a 15-year period. For projects that opt in, a Non-Material Modification will be made to the Interconnection Agreement for charge limitations that also relieves "saturated" network areas of offpeak overloading.

This project-specific, locationally-variant, temporally-variant, charge/discharge-coupled LSRV pricing signal helps solve the following problems:

- Non-specific pricing between normal summer load relief and event-specific load relief and transmission security needs
- Non-specific locational pricing signals for offpeak load
- Heavy loading on circuits/substations/sub-transmission during offpeak period during heat waves
- Con Edison-identified capacity constraints issue

The plot below demonstrates the LSRV program in-action for a peak week in Con Edison's Jamaica network area. LSRV Notifications are sent on Tuesday, Wednesday, and Thursday for LSRV Events on Wednesday, Thursday, and Friday, respectively. The LSRV Events impose charge limitations and LSRV Multiplier Rates. This pricing signal motivated the DER operator to anticipate peak periods and to plan accordingly by holding charge prior to heat waves to maintain availability during the higher-value Events. Over the medium-term, the program may also motivate battery energy storage projects with additional capacity (>4 hours).



Relationship to VDER Capacity Component

Dispatchable VDER resources participate in the Capacity Component – Alternative 3 (ICAP-Alt3) in which project's ICAP Tag is determined by kWh grid injections during the single statewide coincident peak (CP1) during the ICAP Season (defined as non-holiday weekdays in July and August). ICAP-Alt3 is a construct designed to avoid systemwide capacity costs. It differs from the ICAP-Alt1 and ICAP-Alt2 alternatives, available for non-dispatchable resources, which have no temporal variation or fixed grid-inject windows, respectively. Given that the LSRV-Alt2 proposal concept, designed for dispatchable resources, is a competing pricing signal, it is appropriate to re-consider how the utility should prioritize dispatching under the ICAP and LSRV programs. In particular, it's likely that LSRV Events, called for either local distribution grid needs or for zonal transmission security needs, will be on the same days as potential CP1 hours. A more-predictable ICAP dispatching schedule that is directly tied to LSRV dispatching is more beneficial to grid operators.

We propose ICAP-Alternative 4 (ICAP-Alt4) as a sibling rate design to LSRV-Alt2. Utilities are the most informed about local, zonal, and systemwide grid needs, and their pricing signals should reflect their needs and management. For ICAP-Alt4, the utility may call up to ten ICAP

Hours per ICAP Season twenty-one hours in advance, with a maximum of two hours per day. A project's ICAP Tag is the average kW performance during the ten ICAP Hours. If an ICAP Hour is on the same day as an LSRV Event, and the ICAP Hour does not overlap with the LSRV Event, that ICAP Hour is automatically reported as the minimum of the actual ICAP Hour performance and the relevant NYISO Capacity Accreditation Factor (CAF)[50] for the proper duration energy storage resource class (e.g., two-hour, four-hour, six-hour, or eight-hour).The compensation ICAP-Alt4 Tag is the average ICAP-Alt4 performance during ICAP Hours.

[50] The NYISO CAF, reported annually at https://www.nyiso.com/accreditation, are designed to reflect hat resource usage profiles for non-coincident peaks may not overlap with statewide coincident peaks.

V. DPS Questions

1. **Is a two-year cadence for LSRV long enough for developers to plan and get to the 25% interconnection downpayment stage of a project? Should the LSRV remain in effect one or two additional years if costs in an area change with the next MCOS filing?**

   A two-year cadence for LSRV zones is likely to limit its impact in driving new storage projects. Two years is generally shorter than the development timeline for distributed BESS, particularly when including the time involved in securing site control for property suitable for a project. Given that LSRV pricing signals will drive site control and underwriting decisions, it is important to maintain availability of current LSRV capacity (and values) once projects have entered the interconnection process. To the extent that there is still remaining LSRV capacity at the end of the two-year period, NineDot recommends that projects that have entered the interconnection process, even before reaching the interconnection agreement milestone, have an ability to lock in LSRV rates.

   In addition to LSRV, it's important for the Commission to consider the cadence of DRV modifications. In general, NineDot agrees that a two-year cycle for updating DRV values is reasonable. However, DRV has not been updated in eight years, and the most recent MCOS studies are now more than eight months old; as such, we recommend that the Commission authorize the updated DRV values and keep them in effect until the end of 2030 or a minimum of three years from the adoption of updated DRV tariffs. This will provide the stability needed by DER developers to finance their projects.

2. **How should results of the new LSRV and DRV be tracked so that in 5 to 10 years the success of this proposal can be best evaluated?** Deployments of DERs should be tracked under the LSRV and DRV tariffs. In addition, solar and BESS performance should be measured, including load reduction within the defined performance windows and the peak hour. Deployment data at given compensation levels and performance data would enable meaningful analysis of the value these assets are providing to the grid under the DRV and LSRV frameworks. Evaluation, measurement, and verification metrics should be:

- **Peak reduction and reliability**: Grid injections from VDER resources during DRV hours, LSRV events, transmission-security events
- **Cost reduction and ratepayer affordability**: Deferred or avoided traditional infrastructure upgrade projects (within the current or future capital plans), including the period of deferment, associated capital costs, and estimated annualized operating cost reductions
- **Futureproofing**: Changes to peak load forecasts due to VDER resources
- **Grid efficiency**: Increased efficiency of existing substations due to increased off-peak consumption and flattened peak demand

3. **Intentionally skipped.**

4. **What is the most reasonable way of allocating MW for a system-wide transmission project to the underlying substations when calculating a weighted average marginal cost per substation?** System-wide transmission costs should be measured based on the demand that the transmission is being built to serve. The utilities should provide information about where load growth is driving the need for the new transmission project. MW should be allocated based on the use of the transmission project to serve that demand. It is important that the MW reflects the demand growth as opposed to the transmission line capacity. For example, a 300 MW transmission line is built to meet system load growth of 150 MW seen across five networks, the 150 MW should be divided among the five networks proportional to the growth.

5. **What specific language on non-price terms and conditions should be enumerated for LSRV eligibility?** See LSRV-Alt2 Compensation Rate Design, Terms and Conditions on Page 39 for specific price and non-price terms and conditions.
.
6. **Should the kW for each year used in Con Edison's and O&R's ten year levelized $/kW-yr avoided cost calculations be discounted so as to produce a levelized cost which represents the net present value of the revenue requirement of the traditional solution investments divided by the net present value of demand that drove those**

investments? See footnote 82 on page 33 of the August 2025 MCOS Order which notes that in leveling unit cost, dividing the present value of the investment by the present value of the demand would spread costs across capacity as it is expected to be used. Yes, it is appropriate to use levelized costs. The MCOS methodology, in which the core inputs are annual project-level cost at each segment, necessitates using a levelization/annualization step. This is an essential step within the method. See Appendix 2.

7. **Intentionally skipped.**

Appendix 1: BESS Solution to Load Growth Needs

Case Study: Corona No. 1 has a projected need of **29 MW in 2034**
The 2025 substation capability utilization is 36%

TEN YEAR RATEPAYER SAVINGS: $1.95 billion**

	Traditional Solution	BESS Solution
Project specifications	New substation (358 MW) + Load transfer (177 MW)	12, 5-MW VDER BESS (60 MW)
Sizing	Requires overbuilding, > 12X the need	Can be right-sized to meet the need
Timing	6-8 years	2-3 years
Project Cost	$1,731 Mln	Paid by developer
Annual Ratepayer Cost	**$214 Mln**	**$18.6 Mln**
$/kWh	New capacity: $598/kW-yr Load need: $7,382/kW-yr	$305/kW-yr*

Assumes BESS capacity of 2X load need

**Staff proposal for DRV + LSRV adder*
***In nominal value*

Appendix 2: Model Tariff and Rate Design for Grid Export Compensation for Front-of-the-Meter "Community" Battery Energy Storage Systems

To Be Modified After NYS PSC VDER DRV/LSRV Order

Background

Public utility commissions across the United States are actively soliciting information about fair, equitable, and just rate designs for compensating the performance from front-of-the-meter (FTM) distribution-grid-connected dispatchable battery energy storage systems (BESS)[51]. These projects, typically limited to 5-10 MWac interconnections, have been termed "Community Batteries," "Community Energy Storage," or "Small Offsite BESS" and are emerging as a significant U.S. market segment.

Community Batteries have the economies of scale and safety features of larger-scale projects while providing real-world "grid-edge" localized distribution benefits. Under the appropriate operational discharge profile and compensation rate design, Community Batteries can provide measurable grid-reliability and grid-resiliency benefits which should be compensated based on the avoided or deferred costs of the operating expenses of "but-for" traditional grid infrastructure upgrades. Deferral of expensive grid infrastructure provides substantial grid benefits while providing direct ratepayer relief, which serves as a critical solution to the U.S. energy affordability crisis.

New York State's marginal cost of service (MCOS) methodology provides a replicable framework that can be consistently applied by utilities and utility regulators across the county. In this Appendix, the New York State procedure is summarized as a tool for jurisdictions outside New York to apply in their analogous rate design proceedings. Each procedural step is provided with sample data from Con Edison's or other New York utility's rate filing.

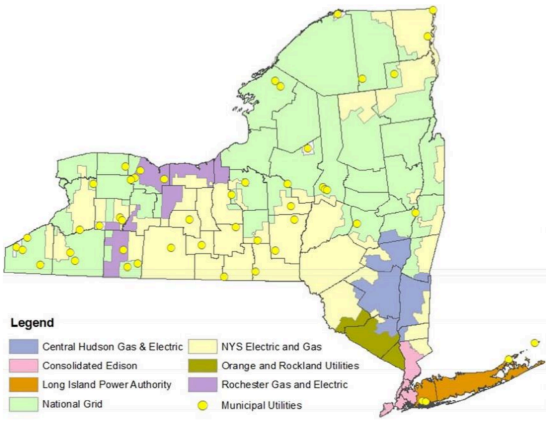
As described further, the method uses routine and real-world utility cost and planning data to calculate a system-wide and locationally-variant marginal cost of service rates that are used to fairly and justly compensate distributed energy resources (DERs) for their tangible and quantifiable benefits to local distribution power systems. Over a long-term planning horizon, this compensation structure is designed to motivate the deployment of DERs that avoid or defer the load-growth-triggered system expansion upgrades. The distributed resources are

[51] Active utility commission proceedings include: the Maryland Public Service Commission Maryland Energy Storage Program (MESP), the Illinois Commerce Commission (ICC) implementation of the Clean and Reliable Grid Affordability Act (CRGA), and the New Jersey Board of Public Utilities (BPU) Garden State Energy Storage Program (GSESP). Similar to New York's 6 GWx2030 goal, MD's goal is 3 GW x 2033, IL's is 3 GW x 2030, and NJ's is 2 GW x 2030, and New York's Community Battery program can act as a useful framework, as New York's nation-leading Community Distributed Generation (CDG) solar program has for community solar.

directly incorporated into medium-term and long-term system planning, and due to the relative speed to DER deployment get integrated in *actual* load profiles and forward-looking load forecasts.

New York State Procedure for Calculating Community Battery Distribution Grid Value (System-wide Average and Locational Adders)

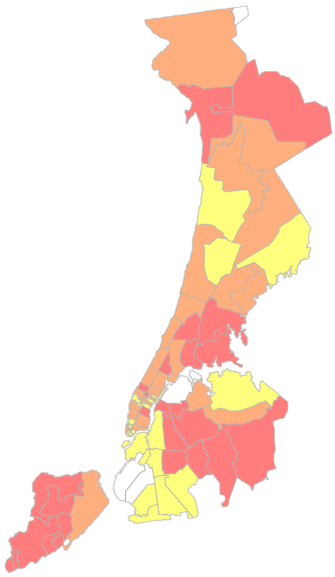
- The utility is to provide a complete list of all current distribution area substations within its service territory and a forecast of new area substations to be constructed over a ten-year planning horizon.



New York State Electric Utility Service Territories

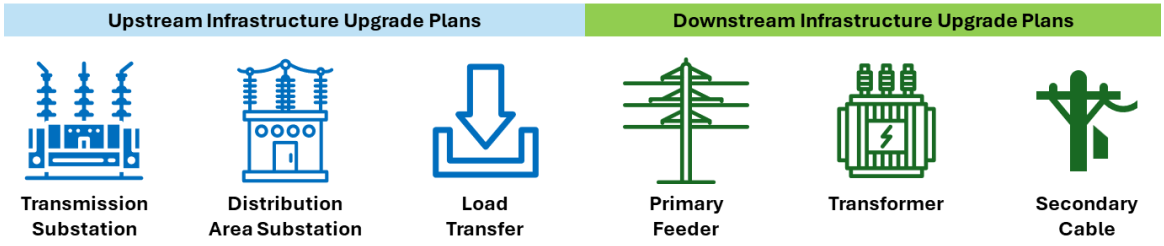
Number of Current and Planned Distribution Area Substation for New York State Electric Utilities	
Distribution Utility	**Area Substations**
Central Hudson Gas & Electric (CHG&E)	64
Consolidated Edison (Con Edison or ConEd)	69
National Grid (formerly Niagara Mohawk or NiMo)	151
NYS Electric and Gas (NYSEG)	79
Orange & Rockland (ORU or O&R)	59
Rochester Gas and Electric (RG&E)	46
All Joint Utilities[52]	**468**

[52] Long Island Power Authority (LIPA), operated by PSEG-LI, is not regulated by the New York State Public Service Commission and has not yet adopted this methodology and is excluded from this table.



Con Edison's 63 Current Area Substation Areas
New York City and Westchester County

- Based on the most recent or active rate case, the utility is to identify all proposed grid infrastructure upgrades to be completed over the ten-year planning period which are triggered by load growth forecasts and to provide supporting source workpapers. Each upgrade project is classified with its distribution substation and network area and its infrastructure segment (e.g., upstream transmission, distribution area substation, load transfer, primary feeder, transformer, and secondary cable).



Con Edison Proposed Load-Growth-Triggered Upgrades (2025 Rate Case)		
Infrastructure Segment	**Number of Proposed Projects**	**Substation Areas**
Transmission	2	5
Area Substation	17	17
Load Transfers	10	10
Primary Feeder	65	27
Transformer	65	29
Secondary Cable	106	35
All Segments	**265 Proposed Projects**	**69 Substations**

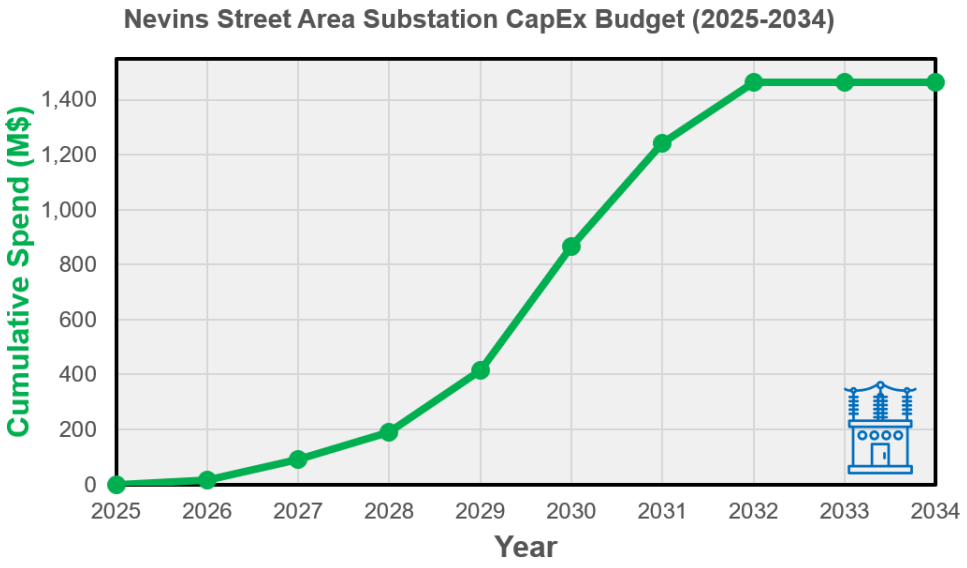
- For each identified upgrade project *i* (265 projects for Con Edison), the following data is collected:
  - proposed in-service year, T_i
  - cost breakdown in each year *t* during the ten-year planning period, $CapEx_i[t]$
  - total project cost, $\sum_{t=1}^{T} CapEx_i[t]$
  - technical load-serving capability addition (at local reliability standard), *M*
  - load growth forecasted by end of ten-year planning period, L_i
  - spare capacity anticipated by end of planning period (difference between technical capability and ten-year load growth forecast)

Con Edison Infrastructure Upgrade Capital Expenses (CapEx)			
Cost Segment	**Cumulative Project Costs (M$)**	**Load Growth Forecast (10 yr.) (MW)**	**Additional Capability (MW)**
Transmission	$1,447	262	1,790
Area Substation	$7,419	623	3,035
Load Transfers	$2,976	-	1,163
Primary Feeder	$13	-	71
Transformer	$6	-	64
Secondary Cable	$17	-	77
All Segments	**$11,878M**	**885**	

For Con Edison's 265 planned load-growth-triggered infrastructure upgrade projects, there is $11.9 billion of capital expenses (CapEx) over a ten-year period, with the majority ($7.4 billion or 62%) for newly established or upgraded distribution area substations.

For each year *t* over the ten-year planning horizon, the project-level annual capital costs are entered into a standardized table. A sample for an individual project is provided below

Con Edison New Nevins Street Area Substation Infrastructure Segment: Distribution Area Substation (Upstream) In Service Year: 2032 Total Project Cost: $1,465 million Technical Capability: 358 MW *Data Source: Rate Case 25-E-0072, EIOP-7, Pages 79-84*					
10-Year Planning Period *t*	**Annual CapEx (M$)** *CapEx[t]*	**Cumulative CapEx (M$)**	**Triggering Load Need (MW)** *L*	**Technical Capability (MW)** *M*	**Spare Capacity (MW)** *M - L*
2025	$0	**$0**	0	0	0
2026	$15	**$15**	0	0	0
2027	$75	**$90**	0	0	0
2028	$100	**$190**	0	0	0
2029	$225	**$415**	0	0	0
2030	$450	**$865**	0	0	0
2031	$375	**$1,240**	0	0	0
2032	$225	**$1,465**	4	**358**	354
2033	$0	**$1,465**	15	358	343
2034	$0	**$1,465**	26	358	332



A similar table is provided for each upgrade project as each infrastructure segment, along with reference source data and worksheets from recent Rate Case proceedings.

- A project-level Marginal Cost of Service (MCOS) -- the incremental cost the utility incurs (paid by ratepayers) to serve one additional unit of load, holding existing system configuration constant, over a planning horizon -- is calculated for each year of the planning cycle[53].

    - For pre-in-service years, a discounted technical capability is calculated by applying a discount factor equal to the utility's post-tax weighted average cost of capital (WACC). For Con Edison, the 2025 WACC is 6.85%.

Con Edison New Nevins Street Area Substation Discounted Available Capacity (MW) for Pre-In-Service Years In Service Year: 2032 Technical Capability: 358 MW Discount Rate = 6.85%			
Planning Period	**Technical Capability (MW)**	**Capacity Discount**	**Available Capacity (MW)**
2025	0	0.567	**218**
2026	0	0.653	**234**
2027	0	0.701	**251**
2028	0	0.753	**270**
2029	0	0.808	**289**
2030	0	0.868	**311**
2031	0	0.932	**333**
2032	**358**	1.000	**358**
2033	358	1.000	**358**
2034	358	1.000	**358**

    - The CapEx are converted to an annualized operating expense (OpEx) by applying a segment-level *Carrying Charge Loader* factor. This is designed to approximate how upfront construction capital costs convert to an annual ratepayer impact (typically over a 30–50-year period), factoring real-world economics including return on capital (debt and equity), depreciation, taxes (income and property), insurance, and administrative costs.

[53] This methodology includes various assumptions to deal with "lumpiness" of capital spending, for pre-in-service costs, and significant spare capacity from overbuilding. New York utilities have not used a consistent framework, and it would be beneficial to determine such a consistent framework. This WACC-based discounting of technical MW capability (first implemented by Charles River Associates for NYSEG's and RG&E's MCOS filing) can be achieved using actual construction progress during pre-in-service years, but this information is not typically readily available to public utility commissions in a project-by-project basis. This method is a replicable stand-in for more granular cost or progress data.

Con Edison Segment-Level Carrying Charge Loaders *Converts CapEx ($) to OpEx ($/y) over project estimated useful life (EUL)*	
Cost Segment	**Carrying Charge Loader**
Transmission	12.87%
Area Substation	12.21%
Load Transfers[54]	12.21%
Primary Feeder	12.27%
Transformer	10.73%
Secondary Cable	12.14%

For example, a total CapEx cost of $1,465 million for an area substation is equivalent to 12.21% x $1,465 million = $179 million per year for ratepayers.

- An annual inflation adjustment is made to the OpEx based on Blue Chip Consensus Forecast of the Gross Domestic Product (GDP) Implicit Price Deflator (currently, 2.4% for 2026 and 2.1% for 2027-2034).

- The inflation-adjusted OpEx is divided by the discounted Available Capacity for the **project-level *annual* MCOS**.

Con Edison New Nevins Street Area Substation Project-level Marginal Cost of Service (MCOS) Calculation					
Planning Period	**Cum. CapEx (M$)**	**OpEx (M$/y)** 12.21% x CapEx	**Inflation-adjusted OpEx (M$/y)**	**Available Capacity (MW)**	**Project-level Annual MCOS ($/kW)**
2025	**$0**	$0.0	**$0.0**	**218**	**$0.00**
2026	**$15**	$1.8	**$1.9**	**234**	**$8.02**
2027	**$90**	$11.0	**$11.5**	**251**	**$45.76**
2028	**$190**	$23.2	**$24.8**	**270**	**$91.88**
2029	**$415**	$50.7	**$55.2**	**289**	**$190.86**
2030	**$865**	$105.6	**$117.5**	**311**	**$378.34**
2031	**$1,240**	$151.4	**$172.0**	**333**	**$515.82**
2032	**$1,465**	$178.9	**$207.5**	**358**	**$579.60**
2033	**$1,465**	$178.9	**$211.9**	**358**	**$591.77**
2034	**$1,465**	$178.9	**$216.3**	**358**	**$604.19**

- This same method is applied for each project in each substation area at each segment.

[54] Con Edison excluded load transfers from its MCOS study, so the area substation Carrying Charge Loader is applied.

- For each substation area, the same methodology in Step 4 is applied to all projects in each segment. For example, if there are multiple upgrade projects in the same segment for a single substation area, the CapEx costs and Available Capacity costs are aggregated. [55]

- A **substation-level annual MCOS** is calculated by adding the segment-level components in each year. For Con Edison, this means adding the segment-level MCOS for Transmission ("TX"), Area Substation ("S/S"), Load Transfers ("XFER"), Primary Feeder ("HT," for high tension), Transformer ("XFMR"), and Secondary Cable ("LT," for low-tension) to calculate at total annual MCOS for the substation ("TOT").

$$MCOS_{TOT} = MCOS_{TX} + MCOS_{S/S} + MCOS_{XFER} + MCOS_{HT} + MCOS_{XFMR} + MCOS_{LT}$$

- A **substation-level levelized (or annualized) MCOS** is calculated that converts the ten annual MCOSs to an equivalent single-year payment, where *r* is the discount rate set as the after-tax WACC and NPV is the net present value function:

$$Levelized\ MCOS = \frac{NPV(r, MCOS[t])}{\frac{1-(1+r)^{-10}}{r}}$$

- The **system-wide levelized MCOS** is calculated as the weighted average of substation-level MCOSs, weighted based on the total upgraded capacity (by the end of the planning period) across all segments.

- The system-wide levelized MCOS (in $/kW-year) is converted to a **fixed $/kWh rate** by determining the top peak 200-350 hours per year when load relief from distributed energy resources will offset the need for these planned traditional grid upgrades. For example, if the utility determines that the "peak" period is 60 days during the summer period with a daily need of four hours load relief, the grid export compensation rate is the system-wide levelized MCOS divided by 240 hours. For New York State's Value of Distributed Energy Resources (VDER) Value Stack Tariff, this rate is called the Demand Reduction Value (DRV) component, and the rate is fixed for the first ten years of operations. This contrasts with the 30–50-year lock-in for rate-based traditional capital projects. A lock-in period balances the "bankability" for distributed energy resources projects with the variability of cost-based MCOS with load growth and changing load profiles.

- A **specific locational adder** to the fixed $/kWh rate for higher-cost substation areas with the highest 5-10 $MCOS_{TOT}$ costs. This is operationalized with a series of 10-15 utility call events each year during high demand peak periods similar to demand-response programs. In New York, this is the VDER Locational Service Relief Value (LSRV) adder, with potential compensation equivalent to 25% of the system-wide levelized MCOS and associated terms and conditions.

[55] This typically only applies for downstream projects; there is typically only a single upstream project for a given substation area.

Appendix 3: Marginal Cost Calculation Economics

Marginal cost studies have a long-established record of using *cost per incremental demand served* (i.e., $3,287/kW for Parkchester No. 1) and not *unit cost* or *cost per additional technical capability* (i.e., $1,643/kW for Parkchester No. 1). Multiple seminal economic analyses on marginal costs provide a clear and compelling record.

- One of the earliest economic workswork on marginal costs for utilities is *The General Welfare in Relation to Problems of Taxation and of Railway and Utility Rates* written by Harold Hotelling in 1938. Marginal cost is defined as: "This additional net cost, or marginal cost, will include the cost of the additional labor and other resources required for the particular item of service or product involved, beyond what would be required without the production of that particular item."
- The seminal and most-influential work is *The Economics of Regulation (Volume 1: Economic Principles)*, by Alfred Kahn published in 1970. In Chapter 3, "Marginal Cost Pricing" describing the principles of Long-Run Marginal Cost (LRMC), it is stated that: "Similarly, on the supply side, capacity is constantly changing. Typically, public utility companies must build in advance of demand to be in a position to meet unexpected peak requirements and simply because the investment process is a lumpy one - additions to capacity are most economically made in large units. Therefore, at any given time, there is almost certain to be excess capacity, which will remain idle if customers are charged long run marginal costs. What, in these circumstances, is the proper measure of marginal costs? Or, to put the question another way, how far into the future should the calculation of long-run marginal costs extend?" The LRMC is based on the cost per demand served for a selected planning horizon.

Appendix 4: Corrected WACC Discount Rate

For Con Edison, Staff applies a discount rate of 8.42% to calculate a ten-year levelized MCOS for each substation[56]. This discount rate is selected from Con Edison's Economic Carrying Charge calculation inputs. The Economic Carrying Charge is, in turn, used as a static input for segment-level Carrying Charge Loader factors[57]. The Carrying Charge Loaders are applied to convert Capital Expenses to Annual Costs[58]. The Economic Carrying Charge is based on a *pre-tax* Revenue Requirement for Working Capital, adding the Income Tax Component (1.57%) to the *after-tax* weighted cost of capital (WACC) overall return (6.85%). The Income Tax Component[59] and Revenue Requirements for Working Capital[60] are then calculated as:

$$Income\ Tax\ Component = \frac{Tax\ Rate}{1-Tax\ Rate} \times (Cost\ of\ Preferred + Cost\ of\ Common\ Equity)$$

$$Income\ Tax\ Component = \frac{26.14\%}{1-26.14\%} \times (0.00\% + 4.44\%)$$

$$Income\ Tax\ Component = \frac{26.14\%}{73.87\%} \times 4.44\%$$

$$Income\ Tax\ Component = 1.57\%$$

$$Revenue\ Requirement\ for\ Working\ Capital = After - tax\ WACC + Income\ Tax\ Component$$

$$Revenue\ Requirement\ for\ Working\ Capital = 6.85\% + 1.57\%$$

$$Revenue\ Requirement\ for\ Working\ Capital = 8.42\%$$

[56] This discount rate is used in cells CECONY!BE1 for project-specific levelized MCOS calculations and CECONY!CO3 for substation-level levelized total MCOS calculations.
[57] Segments include Transmission, Substation, Primary, Transformer, and Secondary cost centers.
[58] The five Carrying Charge Loaders are: Transmission = 12.87%, Substation = 12.21%, Primary = 12.27%, Transformer = 10.73%, and Secondary = 12.14%. For example, an Area Substation with a total capital expense of $100 million has equivalent annualized cost of 12.21% x $100 million = $12.21 million per year.
[59] The "Cost of Debt" is disregarded from this equation, because debt interest is not taxable and is deductible.
[60] Note that Con Edison's July 2025 MCOS filing erroneously calculated the Income Tax Component by using the Cost of Debt (2.41%) in place of the Cost of Preferred (0.00%) in the Derivation of the Income Tax Component resulting in an incorrect value for Revenue Requirement for Working Capital of 9.27%. This formula error is why the hard-coded discount rate on Con Edison's Economics Carrying Charge spreadsheet (8.42%) does not match the Derivation of the Revenue Requirement for Working Capital Factor on the 'Rev Req for Working Cap Factor' workbook (9.27%) in Con Edison's MCOS compliance filing. Further note that Con Edison's 2017 MCOS filing under the VDER Value Stack proceeding (used to set the initial DRV and LSRV component rates) included the same calculation error. Since corporate tax rates were materially higher in that era (39.62% vs 26.14%), the 2017 mistake had more impact on the revenue requirement (9.98% corrected vs.11.73% reported, a difference of 175 basis points).

As described in NYSEG's and RG&E's Marginal Electricity Delivery Service Cost Study, "[t]he discount rate is the Companies' *current, after-tax, weighted average cost of capital* which represents the rate of return the Company can earn over the service life of a plant addition." As such, the correct Con Edison discount rate is the after-tax WACC rate of 6.85%, not the pre-tax revenue requirement of 8.42% as applied by Staff (nor the miscalculated pre-tax revenue requirement of 9.27% provided within Con Edison's filing).

Appendix 5: Corrected Substation Labeling in DPS Staff Con Edison Workpaper Spreadsheet

In Con Edison's July 2025 MCOS filing, multiple naming conventions were applied to the substations area labels. This inconsistency impacts how the upgraded station capabilities are aggregated within Staff's Con Edison Workpaper. For the following four substation areas, the naming conventions must be harmonized in Staff's Spreadsheet:

Label A	Cell A	Label B	Cell B	Staff MW	Correct MW
"Fox Hills 33kV"	CC28	"Fox Hills"	AB251	9.7	127.7
"Gateway Park"	CC30	"Gateway"	AB247	358.0	716.0
"Parkchester No. 1"	CC51	"Parkchester #2"	AB245	1.4	77.4
"Parkchester No. 2"	CC52	"Parkchester #1"	AB252	2.0	83.0

APPENDIX 6

Con Edison Distribution Engineering Department Bulletin No. B-380, Rev. 0

"Underground Network Two Feeder Two Transformer service for the installation of 5000 kW of DER with contingency curtailment to 3330 kW of export"

In this bulletin for DER interconnections issued in 2022, Con Edison included the following language and graphic, which specified the "DER (Battery) must be able to support custom charging cycles where a prescribed level of charging is given for each hour" (See page 2).

DISTRIBUTION ENGINEERING DEPARTMENT BULLETIN

Bulletin No. B-380

Application: Applies to all Electric Operations Regions

Date: 12/01/2022

Title: Underground Network Two Feeder Two Transformer service for the installation of 5000 kW of DER with contingency curtailment to 3330 kW of export

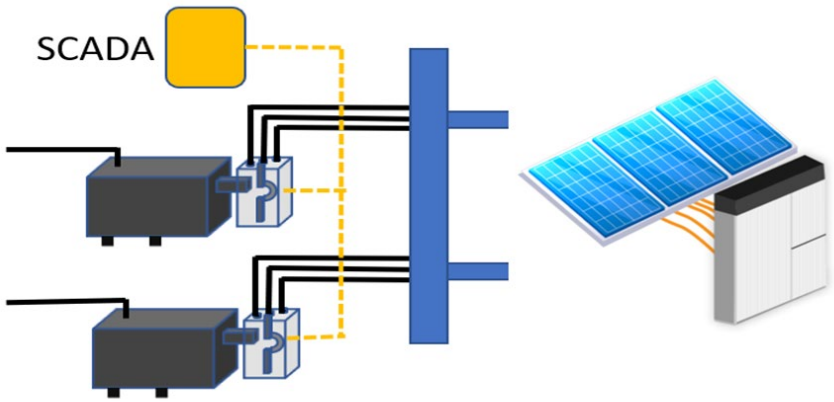
Safety
Standards
Work Methods

1.0 PURPOSE

For all interconnection applications received and approved by Con Edison after the publishing date, the following N-1 design can be offered to distributed energy resource (DER) customers/developers seeking to interconnect in an N-1 or N-2 area that have been ruled with a multibank installation. This design shall be offered to DER only installations, with no traditional customer load, to reduce the cost of infrastructure requirements and further promote interconnection. For customers/developers seeking participation in Con Edison contracted programs (e.g. Non Wired Services, Demonstration projects, other Energy Efficiency Demand Response programs), please check their policy when considering this contingency design. Should DE find any violations in the load flow, DE shall immediately contact the respective group to request an updated ruling. Note charging rates and hours are to be determined by regional engineering through feeder concurrence.

2.0 Design

The deign shall consist of a 2-2500kVA underground network transformers with 277/480V secondary service and SCADA monitoring and control. The selected transformer shall comply with E-2002 table 6 load cycles and continuous ratings. Finally, the selected network protector shall be rated to carry 5100A.



3.0 Operating Characteristics:

3.1 Charge / Discharge Curve: The design shall allow for the customers/developers to be able to charge/discharge their desired capacity. The curve below is for illustration only, the charging hours and rates shall be determined through the existing feeder concurrence process. The illustration below explains the following:

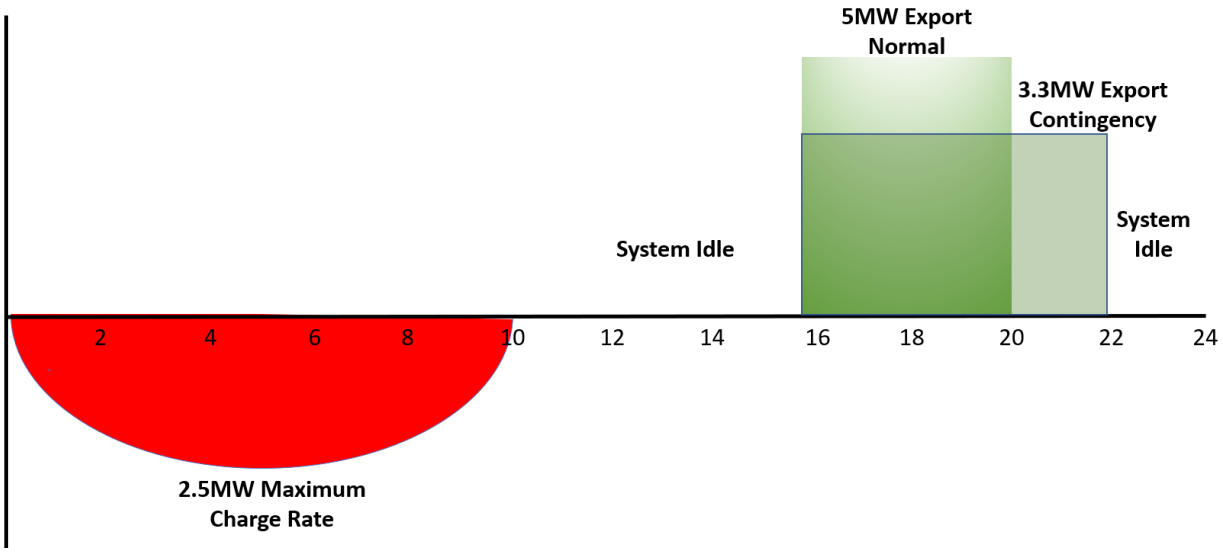
3.1.1 Discharging

3.1.1.1 Normal: With two feeders and two transformers in service, supplying the bus table, the DER shall be able to export 5MW of energy back to the system for 4 hours.

3.1.1.2 Contingency: At the loss of one feeder, the DER shall be curtailed to export no more than 3.33MW (133% of transformer nameplate) for up to 6 hours.

3.1.2 Charging: The DER (Battery) must be able to support custom charging cycles where a prescribed level of charging is given for each hour. Below is an example graph and table of a shaped charging cycle with the maximum charging rate and prescribed hourly rates, shown in the table, to reach the desired capacity.

2 Feeder 2 Transformer Normal & Contingency Charge / Discharge Window



Time	Charge Rate (kW)
12am-1am	1575
1am-2am	1675
2am-3am	1875
3am-4am	2375
4am-5am	2500
5m-6am	2500
6am-7am	2375
7am-8am	1875
8am-9am	1675
9am-10am	1575
Total Capacity (kWh)	**20000**

4.0 Protection:

4.1 NWP Microprocessor Relay: Two Stage Insensitive Trip with Time Delay, a new trip mode, shall be selected as the tripping scheme on each relay. The backfeed percentage set on each NWP shall be provided by DE and based on the understanding that if the reverse power flow on any one NWP exceeds 150% but remains less than 220% of transformer nameplate, the relay shall issue a time delayed trip up to 1 min. At any point in time, should the DER exceed 220% of transformer nameplate the relay shall issue an instantaneous trip. The time delay will be based on the time it takes to curtail the customer/developer's system, described in the SCADA communications section. Finally, two-stage closing with permissive close shall be activated to promote closure of the NWP should the switch remain open on balanced voltages (e.g. following a feeder outage).

4.2 SCADA Communications

4.2.1 Soft Transfer Trip: Each installation shall have communications installed with soft transfer trip. The SCADA system shall issue a trip command to the network protector in the event the associated feeder breaker opens and comes out of service.

4.2.2 Block Charge: SCADA will be equipped with block charge logic to ensure the customer is charging in the approved window and not during the peak periods.

4.2.3 Local Dynamic Curtailment (formerly known as Anti-Islanding): The system will be equipped with a hard-wired connection that appropriately curtails the export from 5MW to 3.33MW upon the loss of a feeder. The NWP microprocessor relay time delay shall be set to account for this time.

4.3 Customer Sided Protection:

4.3.1 To ensure the charging rate is not exceeded, the customer shall install and appropriately set a utility grade relay with 32F element. The 32F element shall be set to the approved charging rate, determined by the feeder concurrence.

4.3.2 DER (battery) control system shall be setup to accommodate the shaped charging curve.

5.0 Reactive Support and Charging Profile

5.1 To reduce the impact the charging cycle will have on feeder loading and to maintain adequate future hosting capacity of the supplying 13, 27, or 33kV feeders the following capability shall be required.

5.1.1 During the charging cycle and DER system idle times the DER (Battery) inverter must be capable of exporting up to 2.5MVar of Reactive Power. Generally, this full amount will be required only at peak system loading times up to 10 days per year. During the remainder of the year up to 1MVar may be requested.

Author: Deepak Khubani

Stephen Pupek (Approval on File)
Department Manager, Distribution Engineering, System Design

APPENDIX 7

Updated Rider Q, Standby Rate Pilot, Compliance Filing of Consolidated Edison Company of New York, Inc.

"Con Edison Standby Service with Locational Variant Daily As-used Demand Pricing Rate"

18-E-0130: In the Matter of Energy Storage Deployment Program

Filed: October 18, 2024

In this proposal, Con Edison defines 12-hour On-Peak, 7-hour Super-Peak, and 12-hour Off-peak time periods for each network area.

Consolidated Edison Company
of New York, Inc.
4 Irving Place
New York NY 10003
www.conEd.com

October 18, 2024

Honorable Michelle L. Phillips
Secretary to the Commission
New York State Public Service Commission
Three Empire State Plaza
Albany, New York 12223-1350

RE: Case 18-E-0130, In the Matter of Energy Storage Deployment Program

Dear Secretary Phillips:

Consolidated Edison Company of New York, Inc. (the "Company") is filing with the Public Service Commission (the "Commission") its proposal related to Rider Q in compliance with the Commission's June 20, 2024 *Order Establishing Updated Storage Goal and Deployment Policy* (the "Order") in the above-referenced case. Such filing was to be made within 60 days of the date of the Order (*i.e.,* on or before August 19, 2024). On August 14, 2024, the Commission granted the Company's request for an extension of the filing deadline to October 18, 2024.

The attached document contains the Company's proposal to meet the requirements of the Order.

Questions regarding this filing can be directed to Ricky Joe at (212) 460-4995.

Sincerely,

/s/ *William A. Atzl, Jr.*

Director - Rate Engineering

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of the Energy Storage Deployment Program	x x x x	Case 18-E-0130

UPDATED RIDER Q, STANDBY RATE PILOT, COMPLIANCE FILING OF CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

I. Introduction

On June 20, 2024, the New York State Public Service Commission (the "Commission") issued an order[1] in Case 18-E-0130 that, amongst other things, directed Consolidated Edison Company of New York, Inc. (the "Company") to submit a filing detailing the Rider Q, Standby Rate Pilot program, including any suggestions for improvement. The Commission directed the Company to make the filing by August 19, 2024.[2]

Rider Q was established in Case 16-E-0060[3] and went into effect in the Company's Electric Tariff[4] on February 1, 2018. Rider Q offers three options: Option A – Customer Chooses Contract Demand, Option B – Locational Variant Daily As-used Demand Pricing, and

[1] *Order Establishing Updated Energy Storage Goal and Deployment Policy* (the "Order").
[2] Ordering Clause 21 of the Order directed that the changes should be filed within 60 days of the Order (i.e., August 19, 2024). On August 14, 2024, the Commission granted the Company's request for an extension of the filing deadline to October 18, 2024.
[3] Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service.
[4] P.S.C. No. 10 - Electricity, Consolidated Edison Company of New York, Inc. Schedule for Electricity Service ("Electric Tariff").

Option C – Export Pilot Credit. The application deadline for Rider Q was December 31, 2021. The Company currently provides service under Rider Q to seven customers.

The following sections describe the Company's proposals to meet the directives of the Order.

II. The Proposal

Rider Q Option A

Currently, Customers under Rider Q Option A have the ability to establish their Contract Demand, subject to an exceedance penalty. The Company is proposing to eliminate Rider Q Option A and permit non-mass market customers with generators to set their Contract Demands under General Rule 20.4.3 of the Electric Tariff. Existing Rider Q Option A customers will be permitted to establish customer-set Contract Demands under this modified general rule.

Rider Q Option B

Alignment of Super-Peak and On-Peak Periods with Local Distribution System Load Curves

Option B of Rider Q is currently a Standby Service rate alternative that replaces As-used Daily Demand Delivery Charges, applicable under Standby Service rates, with Locational Variant Daily As-used Demand Pricing.

Under Standby Service rates, As-used Daily Demand Delivery Charges are assessed for the following time periods:

Summer Months (June through September)

- Monday – Friday, 8 am to 6 pm (referred to herein as Super-Peak)
- Monday – Friday, 8 am to 10 pm (referred to herein as On-Peak)

Other Months

- Monday – Friday, 8 am to 10 pm (referred to herein as On-Peak)

These Standby Service rate time periods are consistent throughout the Company's service territory.

Under the current Rider Q Option B construct, there are 4 location-based Super-Peak periods that correspond to 4-hour Commercial System Relief Program ("CSRP") windows that vary by network load area. CSRP windows are location-based periods for which demand response resources are called to curtail load during CSRP events. Since Rider Q was established in 2018, the Company has updated the CSRP program to expand the CSRP performance periods from 4-hours to 6-hours for certain network load areas, as the standard 4-hour window is no longer sufficient to fully capture the local distribution system's peak hours.[5] The On-Peak period under the current Rider Q Option B is consistent with the Standby Service rates On-Peak period, based on capturing the hours exceeding a 90% loading threshold on the class load shape.[6] Unlike the Super-Peak period, the On-Peak period is the same across all network load areas.[7]

The Company is proposing to eliminate Rider Q and replace Option B with a new Standby Service with Locational Variant Daily As-used Demand Pricing rate ("New Locational Rate") as a new Standby Service rate option in non-mass market service classifications ("SC") (i.e., SCs 5, 8, 9, 12 and 13 and the PASNY Rate Schedule) that will be available to all customers in those SCs. The New Locational Rate updates the As-Used Daily Demand Delivery Charge components to better align the Super-Peak and On-Peak periods to the peak and shoulder peak hours of the local distribution system. For example, the New Locational Rate will set

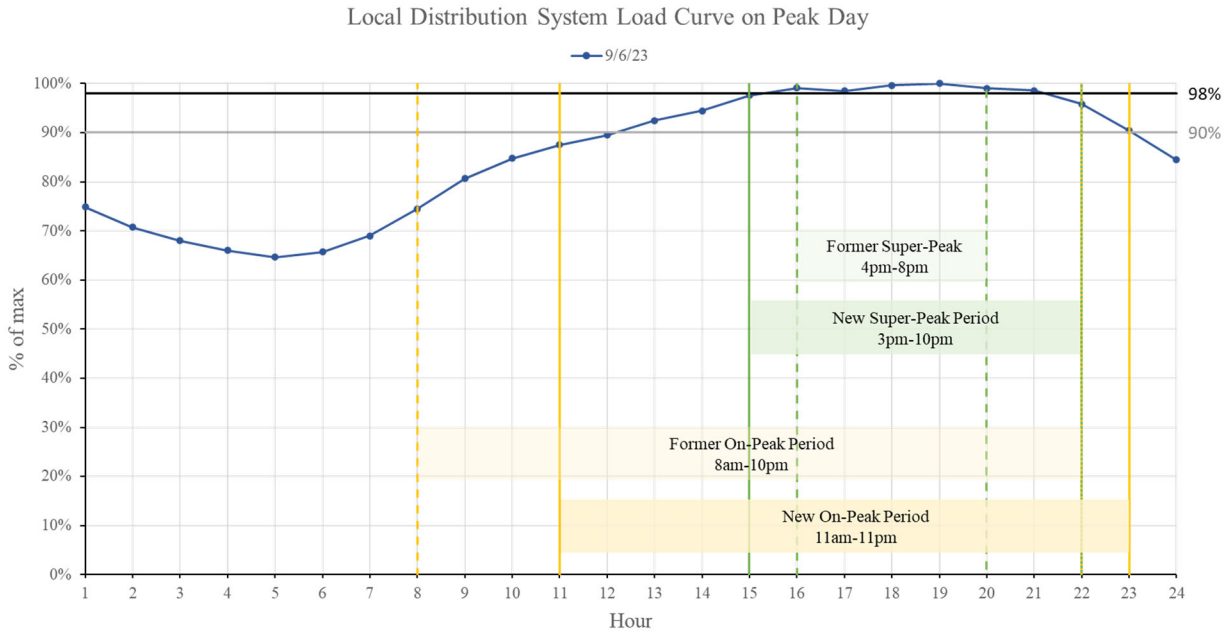
[5] Case 14-E-0423, *Proceeding on Motion of the Commission to Develop Dynamic Load Management Programs*, Order Directing Dynamic Load Management Program Changes (April 21, 2023).
[6] Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Commercial & Industrial Demand Charge Reform Filing of Consolidated Edison Company of New York, Inc. (April 17, 2017).
[7] One exception is the Rider Q Option B On-Peak period corresponding with a 7 pm to 11 pm Super-Peak period. This On-Peak period is 10 am to midnight.

Super-Peak periods aligned with the peak load hours of the current local distribution system load curves, resulting in Super-Peak periods that are longer in duration and not tied to the CSRP program. With these updates, and increased flexibility to update the rate structure, the New Locational Rate will send more efficient and accurate price signals to participating distributed energy resources to shift load away from those hours in alignment with the Company's distribution system deferral efforts.

The Company developed Super-Peak and On-Peak periods to align with the 24-hour, local distribution system peak day load curve data from the prior year using the following methodology. Each local distribution system load curve was normalized on a scale of 0 to 100% of the local distribution system's peak load. Super-Peak periods were established to encompass, where possible, the hours for which the normalized load curves exceeded a 98% loading threshold; On-Peak periods were set for the hours for which the curves exceeded a 90% loading threshold.

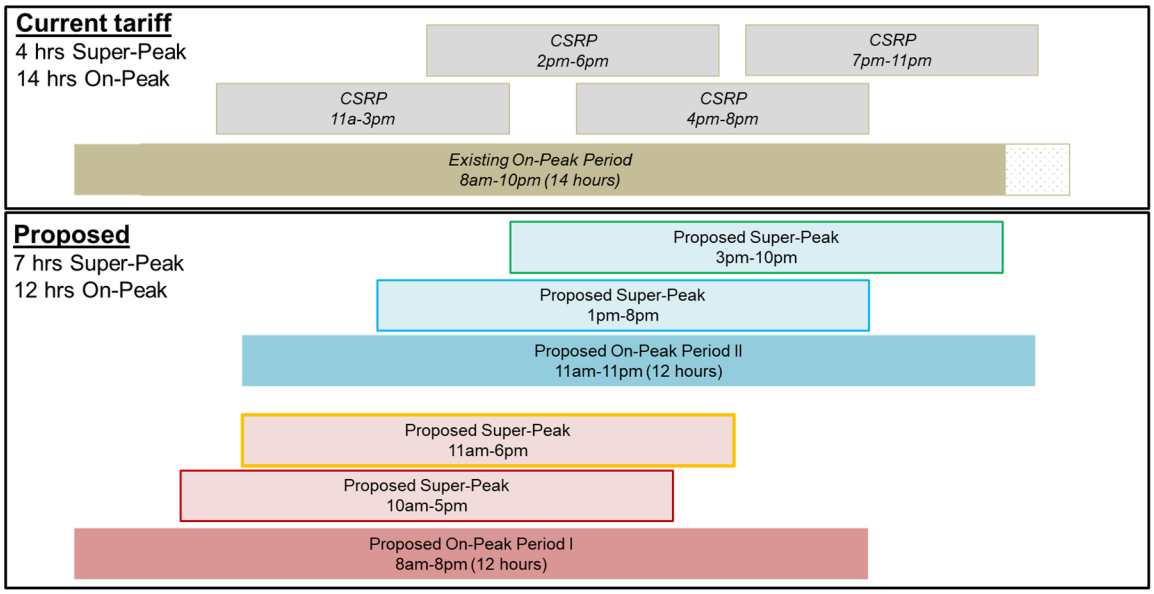
Selecting the Super-Peak and On-Peak periods required setting a balance between the variations in load shapes and peak durations observed among the local distribution systems and the need to preserve consistency in Super-Peak and On-Peak durations among all participating customers. Setting 7-hour Super-Peak periods and 12-hour On-Peak periods yielded the best alignment with the load curve data across the network load areas and captured nearly all peak and shoulder peak hours. Network load areas were grouped together according to the timing of their peak hours. As shown in Figure 1, applying the 98% and 90% loading thresholds to set the Super-Peak and On-Peak periods in an example local distribution system load curve resulted in improved alignment from the current Super-Peak period, which was too short to capture the entire peak period, and the current On-Peak period, which was longer.

Figure 1. Illustration of applying loading thresholds to align Super-Peak and On-Peak periods with an example local distribution system load curve.



The result is two shorter On-Peak periods and four longer Super-Peak periods that are better matched to local distribution system load characteristics as shown in Figure 2 below.

Figure 2. Summary of proposed Rider Q peak periods for 2024-25



While the New Locational Rate provides Super-Peak and On-Peak periods well aligned with current local distribution system load curves, the Company does not expect these curves to stay static over time. In particular, the addition of high volumes of EV charging loads and other electrification loads may drive rapid changes in the load curves within the next ten years. Thus, a periodic review cycle is needed to avoid outdated and misaligned price signals over the long term. On an annual basis, the Company will review the Super-Peak and On-Peak period groupings and move network load areas among the groupings as needed. The Company will publish an information sheet with the New Locational Rate Super-Peak and On-Peak period groupings on the Company's website and update it on an annual basis, as shown in Appendix A. Furthermore, in each electric rate proceeding, the Company will re-examine the methodologies for determining On-Peak and Super-Peak periods, the number of On-Peak periods, the number of Super-Peak periods, and On-Peak and Super-Peak duration and timings, and propose revisions as needed.

Rider Q Option C

Rider Q Option C offers a credit to customers based on the performance of the customer's generation facility during a previous measurement period. The Company is proposing to eliminate Rider Q Option C. Since the inception of Rider Q Option C, the Company has revised its standby and buyback service rates based on the Allocated Cost of Service methodology and eliminated the standby reliability credit for new customers pursuant to the ACOS Order.[8] Given these updates to the Electric Tariff, Rider Q Option C is no longer appropriate. There are currently no customers being served under Rider Q Option C.

[8] Case 15-E-0751, *Order Establishing Updated Standby Service Rates and Implementing Optional Mass Market Demand Rates*, issued October 13, 2023("ACOS Order").

III. New Locational Rate Design

The New Locational Rate is based on the revenue requirement for Rate Year 2 of the Company's rate plan in Case 22-E-0064.[9] Customer charges and contract demand charges for the New Locational Rate are set equal to the customer charges and contract demand charges of the otherwise applicable Standby Service rates. The as-used daily demand charges of the New Locational Rate were developed as described below.

Time Periods for As-Used Daily Demand Delivery Charges

Under the current Standby Service rate construct, as-used daily demand charges are assessed from: (1) 8 am to 6 pm, Monday through Friday in the summer for the Super-Peak period; and (2) from 8 am to 10 pm, Monday through Friday for the On-Peak period. The existing Rider Q Option B includes 4-hour Super-Peak periods and 14-hour On-Peak periods in summer that vary by location and a 14-hour winter On-Peak period. The existing Rider Q Option B includes two sets of summer as-used daily demand charges. One set reflects a 25 percent revenue shift from the summer On-Peak period to the summer Super-Peak period for customers in CSRP networks, and a second set reflects a 35 percent shift for customers also in a DLRP Tier 2 network. Under the New Locational Rate, the Company proposes a single set of as-used daily demand charges.

In developing as-used daily demand charges for the New Locational Rate, the summer Super-Peak periods have been updated from 4 hours to 7 hours, and the summer and winter On-Peak periods have been updated from 14 hours to 12 hours. The 7-hour Super-Peak and the 12-hour On-Peak demand periods of the New Locational Rate windows are as follows:

[9] The Company would need to recalculate Standby Service rates for subsequent rate years based on the delivery revenue requirement for the applicable year that such rates would become effective.

	Days	Window (1)	Window (2)	Window (3)	Window (4)
Summer Super-Peak	Mon-Fri	10am-5pm	11am-6pm	1pm-8pm	3pm-10pm
Summer/Winter On-Peak	Mon-Fri	8am-8pm	8am-8pm	11am-11pm	11am-11pm

As-used daily demand billing determinants for the new Super-Peak and On-Peak periods have been established based on the Company's 2019 demand analysis filed in Case 22-E-0064. The class revenue requirements to be recovered through as-used daily demand delivery charges were developed based on the summer and winter required revenues priced out at the otherwise applicable existing Standby Service rates. Applying the methodology to align Super-Peak and On-Peak periods to local distribution system load curves aligned the On-Peak period to the shoulder peak hours and set the outer bounds for the periods when battery charging should be encouraged. Strengthening the price signal of the On-Peak charge can guide charging loads away from the shoulder peak hours where there is potential to set new local distribution system peaks. To provide a stronger On-Peak charge, the Company applied a 15 percent revenue shift from the summer On-Peak period to the summer Super-Peak period, representing a gradual change from the previous rate design. The as-used daily demand delivery charge revenue requirements were then divided by the new as-used daily demand billing determinants to develop the as-used daily demand charges for the summer On-Peak and Super-Peak periods and the winter On-Peak period.

Present and Proposed Rates

Included in Appendix B is a comparison of the present Standby Service Rider Q Rates and the proposed New Locational Rates.

IV. Draft Tariff Leaves

Included in Appendices C and D in clean and redlined format, respectively, are: (1) draft amendments to the Company's Electric Tariff, which is applicable to its customers in the City of New York and the County of Westchester; and (2) draft amendments to the Company's Schedule for PASNY Delivery Service, P.S.C. No. 12 – Electricity (the "PASNY Tariff"),[10] which is applicable to delivery by the Company of power and associated energy to New York Power Authority Public Customers under the PASNY Tariff. The Company is proposing the following tariff changes.

1. Rider Q, Standby Rate Pilot, and references to Rider Q within the Electric and PASNY Tariffs have been eliminated.
    a. General Rule 20.3.3 "Customers with Targeted Exemptions," General Rule 20.3.4 "Additional Requirements," and references within the Electric Tariff to those General Rules have been eliminated since the Targeted Exemption has expired with no participants and refers to Rider Q which is being eliminated.
2. Added the New Locational Rate as SC 5 Rate V, SC 8 Rate VI, SC 9 Rate VI, SC 12 Rate VI, SC 13 Rate III, and PASNY Rate V.
    a. All rates and charges of the Customer's otherwise applicable Standby Service rate apply, with the replacement of the As-used Daily Demand Delivery Charges.

[10] This schedule is also titled, "Delivery Service Rate Schedule Implementing and Part of the Service Agreement Between the Power Authority of the State of New York ("PASNY" or "NYPA") and Consolidated Edison Company of New York, Inc. (the "Company"), dated March 10, 1989, for the Delivery by the Company of Power and Associated Energy to Authority Public Customers."

b. The New Locational Rate is available on an opt-in basis to all metered Customers. A Customer who elects to transfer from the New Locational Rate to another rate will be ineligible for billing under the New Locational Rate for a period of one year from the date of such transfer. Customers participating under the New Locational Rate are not restricted from participating in Rider T – Commercial Demand Response Programs, Rider AC – Term- and Auto-Dynamic Load Management Programs, and in Company demand management programs pursuant to Commission Orders in Case 12-E-0503.

c. The rates and applicable time periods under the New Locational Rate will vary based on the customer's network. The applicable time periods are established by the Company annually for each network based on local system needs and will be posted on the Company's website no later than January 1 for the upcoming year. The methodologies for determining On-Peak and Super-Peak periods, the number of On-Peak periods, the number of Super-Peak periods, and On-Peak and Super-Peak duration and timings are subject to change in the Company's electric rate proceedings.

d. General Rule 20 has been modified to specify that customers who are required to take service under Standby Service rates can opt to take service under the New Locational Rate. In addition, duplicative language was deleted in General Rule 20.4.1.

e. General Rule 20.5.4 has been modified to specify that customers who elect to be billed on the New Locational Rate will no longer receive the standby reliability

credit since customers taking service under the New Locational Rate are not receiving a phase-in to ACOS-based rates.

f. Application Form G has been modified to provide customers with an option to request the New Locational Rate.

3. General Rule 20.4, Billing under Standby Service Rates, has been amended to permit non-mass market customers with generators to set their Contract Demands.

V. Bill Impacts to Existing Rider Q Customers

As of September 2024, Con Edison has six customers served under Rider Q Rates for at least a 12-month period.[11] These existing Rider Q customers will be given the option to switch to the New Locational Rate or the Standby Service rate. Bill impacts were developed on a total bill basis (including other charges such as supply, surcharges, and taxes) comparing bills under current Rider Q rates to bills under the proposed New Locational Rate. The bill impacts also compare bills under current Rider Q rates to bills under current Standby Service rates. On a total bill basis, existing Rider Q customers switching to the New Locational Rate would see increases between 0.0% and 3.5%. If the existing Rider Q customers elect to switch to Standby Service rates, the total bill increases would be between 0.1% and 1.3%.

VI. Implementation Considerations

The draft tariff leaves included herein are subject to Commission review and public comment in this proceeding and, as such, may be modified based on those reviews. Upon Commission approval of the Company's proposed draft tariff leaves, billing of the various changes included in this filing will require additional time. As such, the Company is requesting that billing system modification costs, currently estimated at approximately $88,000, be deferred

[11] One customer has less than 12-months of service under Rider Q.

and recovered in a subsequent rate proceeding. The Company also requests eight months following a Commission Order approving the New Locational Rate for the design, build and testing activities needed to implement the changes. The proposed funding and timeline will give the Company sufficient opportunity to perform necessary billing system programming and testing of the New Locational Rate.

VII. Conclusion

As described herein, the Company's proposed rate design and draft tariff leaves meet the requirements of the Commission Order and will provide customers with locational variant daily as-used demand pricing. The Company looks forward to working with Staff and other stakeholders to discuss these proposals.

Appendix A

ON-PEAK AND SUPER-PEAK PERIODS FOR 2024

Con Edison Standby Service with Locational Variant Daily As-used Demand Pricing Rate

On-Peak and Super-Peak Periods for 2024

Con Edison's Standby Service with Locational Variant Daily As-used Demand Pricing Rate is a rate customers can elect to be served under. The As-used Daily Demand Delivery Charges are based on customers' daily weekday peak kW demand within both the 12-hour ("On-Peak") and 7-hour ("Super-Peak") time periods designated for their network. These generally correspond with the local distribution system's peak loading periods.

Each network falls within one of two fixed 12-hour On-Peak periods and one of four fixed 7-hour Super-Peak periods. Each On-Peak period has two possible Super-Peak periods, for a total of four possible network categorizations. The possible categorizations are listed below:

12-hour On-Peak	8am – 8pm		11am – 11pm	
7-hour Super-Peak	10am – 5pm	11am – 6pm	1pm – 8pm	3pm – 10pm

Table 1 lists the 12-hour On-Peak and 7-hour Super-Peak periods for each Con Edison network, sorted by borough. Table 2 lists Con Edison networks grouped by On-Peak and Super-Peak periods.

On-Peak and Super-Peak periods assigned to networks may be adjusted annually to better align them with the observed local distribution system peak loading periods.

Please review the tariff for further details including participation requirements and daily On-Peak and Super-Peak pricing. New Distributed Generation customers applying for the Standby Service with Locational Variant Daily As-used Demand Pricing Rate should indicate it on their interconnection application in PowerClerk and fill out Form G accordingly during the interconnection process.

Con Edison Standby Service with Locational Variant Daily As-used Demand Pricing Rate
On-Peak and Super-Peak Periods for 2024

Table 1: Network On-Peak and Super-Peak Periods by Borough

Borough	Network	12-hour On-Peak Period	7-hour Super-Peak Period
Bronx	CENTRAL BRONX	11am-11pm	3pm-10pm
Bronx	FORDHAM	11am-11pm	3pm-10pm
Bronx	NORTHEAST BRONX	11am-11pm	3pm-10pm
Bronx	RIVERDALE	11am-11pm	1pm-8pm
Bronx	SOUTHEAST BRONX	11am-11pm	3pm-10pm
Bronx	WEST BRONX	11am-11pm	1pm-8pm
Brooklyn	BAY RIDGE	11am-11pm	1pm-8pm
Brooklyn	BOROUGH HALL	8am-8pm	11am-6pm
Brooklyn	BRIGHTON BEACH	11am-11pm	1pm-8pm
Brooklyn	CROWN HEIGHTS	11am-11pm	3pm-10pm
Brooklyn	FLATBUSH	11am-11pm	3pm-10pm
Brooklyn	OCEAN PARKWAY	11am-11pm	1pm-8pm
Brooklyn	PARK SLOPE	11am-11pm	3pm-10pm
Brooklyn	PROSPECT PARK	11am-11pm	3pm-10pm
Brooklyn	RIDGEWOOD	11am-11pm	3pm-10pm
Brooklyn	SHEEPSHEAD BAY	11am-11pm	3pm-10pm
Brooklyn	WILLIAMSBURG	11am-11pm	1pm-8pm
Manhattan	BATTERY PARK CITY	8am-8pm	11am-6pm
Manhattan	BEEKMAN	8am-8pm	11am-6pm
Manhattan	BOWLING GREEN	8am-8pm	10am-5pm
Manhattan	CANAL	8am-8pm	11am-6pm
Manhattan	CENTRAL PARK	11am-11pm	1pm-8pm
Manhattan	CHELSEA	8am-8pm	11am-6pm
Manhattan	CITY HALL	8am-8pm	10am-5pm
Manhattan	COLUMBUS CIRCLE	8am-8pm	11am-6pm
Manhattan	COOPER SQUARE	11am-11pm	1pm-8pm
Manhattan	CORTLANDT	8am-8pm	10am-5pm
Manhattan	EMPIRE	8am-8pm	11am-6pm
Manhattan	FASHION	8am-8pm	11am-6pm
Manhattan	FREEDOM	8am-8pm	10am-5pm
Manhattan	FULTON	8am-8pm	10am-5pm
Manhattan	GRAND CENTRAL	8am-8pm	10am-5pm
Manhattan	GREELEY SQUARE	8am-8pm	10am-5pm
Manhattan	GREENWICH	8am-8pm	11am-6pm
Manhattan	HARLEM	11am-11pm	1pm-8pm
Manhattan	HERALD SQUARE	8am-8pm	10am-5pm
Manhattan	HUDSON	11am-11pm	1pm-8pm

Manhattan	HUNTER	8am-8pm	10am-5pm
Manhattan	KIPS BAY	8am-8pm	10am-5pm
Manhattan	LENOX HILL	11am-11pm	1pm-8pm
Manhattan	LINCOLN SQUARE	11am-11pm	1pm-8pm
Manhattan	MADISON SQUARE	8am-8pm	11am-6pm
Manhattan	MIDTOWN WEST	8am-8pm	10am-5pm
Manhattan	PARK PLACE	8am-8pm	10am-5pm
Manhattan	PENNSYLVANIA	8am-8pm	10am-5pm
Manhattan	PLAZA	8am-8pm	10am-5pm
Manhattan	ROCKEFELLER CENTER	8am-8pm	10am-5pm
Manhattan	ROOSEVELT	8am-8pm	11am-6pm
Manhattan	SHERIDAN SQUARE	8am-8pm	11am-6pm
Manhattan	SUTTON	8am-8pm	10am-5pm
Manhattan	TIMES SQUARE	8am-8pm	10am-5pm
Manhattan	TRIBORO	11am-11pm	1pm-8pm
Manhattan	TURTLE BAY	8am-8pm	10am-5pm
Manhattan	WASHINGTON HEIGHTS	11am-11pm	1pm-8pm
Manhattan	YORKVILLE	11am-11pm	1pm-8pm
Queens	BORDEN	11am-11pm	1pm-8pm
Queens	FLUSHING	11am-11pm	3pm-10pm
Queens	JACKSON HEIGHTS	11am-11pm	3pm-10pm
Queens	JAMAICA	11am-11pm	3pm-10pm
Queens	LONG ISLAND CITY	11am-11pm	1pm-8pm
Queens	MASPETH	11am-11pm	1pm-8pm
Queens	REGO PARK	11am-11pm	3pm-10pm
Queens	RICHMOND HILL	11am-11pm	3pm-10pm
Queens	SUNNYSIDE	11am-11pm	1pm-8pm
Staten Island	FOX HILLS	11am-11pm	1pm-8pm
Staten Island	FRESH KILLS	11am-11pm	3pm-10pm
Staten Island	WAINWRIGHT	11am-11pm	1pm-8pm
Staten Island	WILLOWBROOK	11am-11pm	3pm-10pm
Staten Island	WOODROW	11am-11pm	3pm-10pm
Westchester	BUCHANAN	11am-11pm	3pm-10pm
Westchester	CEDAR ST.	11am-11pm	1pm-8pm
Westchester	ELMSFORD #2	11am-11pm	1pm-8pm
Westchester	GRANITE HILL	11am-11pm	3pm-10pm
Westchester	GRASSLANDS	11am-11pm	1pm-8pm
Westchester	HARRISON	8am-8pm	11am-6pm
Westchester	MILLWOOD WEST	11am-11pm	1pm-8pm
Westchester	MOHANSIC	11am-11pm	1pm-8pm
Westchester	OSSINING WEST	11am-11pm	3pm-10pm
Westchester	PLEASANTVILLE	11am-11pm	1pm-8pm
Westchester	ROCKVIEW	11am-11pm	3pm-10pm

Westchester	WASHINGTON ST.	11am-11pm	3pm-10pm
Westchester	WHITE PLAINS	11am-11pm	1pm-8pm

Con Edison Standby Service with Locational Variant Daily As-used Demand Pricing Rate
On-Peak and Super-Peak Periods for 2024

Table 2: Networks by 12-hour On-Peak and 7-hour Super-Peak Period

12-hour On-Peak: **8am-8pm**		*12-hour On-Peak:* **11am-11pm**	
7-hour Super Peak:		*7-hour Super Peak:*	
10am-5pm	**11am-6pm**	**1pm-8pm**	**3pm-10pm**
BOWLING GREEN	BATTERY PARK CITY	BAY RIDGE	BUCHANAN
CITY HALL	BEEKMAN	BORDEN	CENTRAL BRONX
CORTLANDT	BOROUGH HALL	BRIGHTON BEACH	CROWN HEIGHTS
FREEDOM	CANAL	CEDAR ST.	FLATBUSH
FULTON	CHELSEA	CENTRAL PARK	FLUSHING
GRAND CENTRAL	COLUMBUS CIRCLE	COOPER SQUARE	FORDHAM
GREELEY SQUARE	EMPIRE	ELMSFORD #2	FRESH KILLS
HERALD SQUARE	FASHION	FOX HILLS	GRANITE HILL
HUNTER	GREENWICH	GRASSLANDS	JACKSON HEIGHTS
KIPS BAY	HARRISON	HARLEM	JAMAICA
MIDTOWN WEST	MADISON SQUARE	HUDSON	NORTHEAST BRONX
PARK PLACE	ROOSEVELT	LENOX HILL	OSSINING WEST
PENNSYLVANIA	SHERIDAN SQUARE	LINCOLN SQUARE	PARK SLOPE
PLAZA		LONG ISLAND CITY	PROSPECT PARK
ROCKEFELLER CENTER		MASPETH	REGO PARK
SUTTON		MILLWOOD WEST	RICHMOND HILL
TIMES SQUARE		MOHANSIC	RIDGEWOOD
TURTLE BAY		OCEAN PARKWAY	ROCKVIEW
		PLEASANTVILLE	SHEEPSHEAD BAY
		RIVERDALE	SOUTHEAST BRONX
		SUNNYSIDE	WASHINGTON ST.
		TRIBORO	WILLOWBROOK
		WAINWRIGHT	WOODROW
		WASHINGTON HEIGHTS	
		WEST BRONX	
		WHITE PLAINS	
		WILLIAMSBURG	
		YORKVILLE	

APPENDIX 8

Source Data for Con Edison Marginal Cost of Service (MCOS) Filing

Capital Budgets for Area Substations

Major Rate Case 25-E-0072

Electric Infrastructure and Operations Panel (EIOP)

System Expansion & New Business Capital Expenditures (CapEx)

EIOP-7 Updated (UPD): 4/10/2025

EIOP-7: 1/31/2025

Area Substation	Data Source
Newtown	EIOP-7, Pages 56-62
Parkchester #2	EIOP-7, Pages 195-201
Idlewild (new)	EIOP-7 UPD, Pages 69-78
Gateway (new)	EIOP-7, Pages 37-46
Parkview	EIOP-7, Pages 206-210
Mott Haven	EIOP-7, Pages 169-174
Glendale	EIOP-7, Pages 47-55
Fox Hills	EIOP-7, Pages 141-145
Parkchester #1	EIOP-7, Pages 189-194
Millwood West	EIOP-7 UPD, Pages 128-132
Cedar Street	EIOP-7, Pages 67-72
Nevins Street (new)	EIOP-7, Pages 79-84
Grasslands	EIOP-7, Pages 97-102
Hillside (new)	EIOP-7, Pages 64-68
Bruckner	missing
Industry City (new)	EIOP-7, Pages 20-27
Atlantic (new)	EIOP-7 UPD, Pages 2-9

Central Operations / Substation Operations
2025-2029

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Brownsville Area Load Relief – Newtown TR4 and Feeder 38Q05	
Project/Program Manager: Charles Davoren	**Project/Program Number (Level 1):** 26018032
Status: ☐ **Initiation/Planning** ☒ **In-Progress (Projects Only)** ☐ **On-going (Programs Only)**	
Estimated Start Date: 2023	**Estimated Date In Service:** 2026
2025-2029 Funding Request ($000) **Capital:** $126,254 **O&M:** $0	

Work Description:
This project is part of a Company program designed to alleviate forecasted overloads on the 138kV feeders supplying the Brownsville Area Substations. The Company first identified the need for a new substation to provide relief for the Brownsville substation in 2014, but prior load forecasts showed Brooklyn Queens Demand Management (BQDM) deferring the need for the new station until 2032. More recent forecasts, however, show significant, near-term load growth in the area (including adoption of electric vehicles and electric heating) indicate that a new station is needed by 2026).

Because of the risk that subsequent load growth in the area could create reliability issues before the long-term solution can be implemented, the planned Company program includes both interim solutions and a long-term solution, planned for implementation beginning in 2024 and with the final, long-term solution implemented in 2028.

Interim solutions identified to address Brownsville feeder overloads include:

- 2024-2025: Operate the Farragut to Brownsville 138 kV feeders at 143 kV and 0.97 Power Factor
- 2024-2033: Install/maintain alternate utility and customer sided solutions for BQDM
- 2024: Transfer Metropolitan Transportation Authority (MTA) transit rectifier station (HTV70S1) from Crown Heights (3B) to Flatbush (4B), reducing Brownsville feeder load by approximately 2 MW. (completed)
- 2025: Transfer MTA transit rectifier station (HTV2337) and Starr 4kV Autoloop from Ridgewood (SB) to Maspeth (6Q), reducing feeder load by approximately 4 MW.
- 2026: Install a fourth transformer at Newtown and a new 138kV sub-transmission feeder (38Q05) from the Vernon substation to the Newtown Substation (making capacity available on the 138 kV Vernon sub-transmission feeders supplying Glendale, Newtown & Amtrak) and transfer 60 MW from Brownsville No. 1 to Glendale.

The long-term solution to providing Brownsville load relief under this program is to construct the new Gateway Park Area Substation, to be supplied by the new Brooklyn Clean Energy Hub via four new 138kV sub-transmission feeders. The capital projects involved in completing the Gateway Park Area Substation and alleviating forecasted Brownsville overloads include:

- 2028: Establish Gateway Park Area Substation No. 1

- 2028: Split Crown Heights network and transfer 120 MW from Brownsville No. 1 to Gateway Park No. 1

This project is part of the interim solutions for load relief at the Brownsville Area Substations and is designed to provide interim load relief at Brownsville in 2026, prior to implementation of the long-term solution in 2028.

To implement this interim solution, the Company will install a new 138kV sub-transmission feeder (38Q05) from Vernon Substation to Newtown Substation along with a fourth 138kV/27kV transformer there. Newtown Substation is currently supplied by three 138kV feeders that also originate from the Vernon Substation. These three feeders (38Q02, 38Q03 and 38Q04/Q04T) also supply, along with Feeder 38Q01 from Vernon Substation, the Glendale Area Substation. The addition of Feeder 38Q05 to supply Newtown Substation increases the available capacity on Feeders 38Q01-38Q04 and, thus, the capacity at Glendale Substation. This increased capacity at Glendale Substation allows the station to accept a 60MW network transfer from Brownsville No. 1, to provide load relief for the latter. (Coincidentally, load constraints are also forecasted for the Newtown substation during the 10-year LRP period, and installation of this equipment will alleviate those constraints as well.) Then, the Company will transfer approximately 60MW from Brownsville #1 Substation to Glendale Substation (under a separate project).

The major scopes of work to be completed to install the fourth transformer at Newtown and feeder 38Q05 include:

- Connect and install new 138/27kV transformer inter service at Newtown 27kV substation, along with associated equipment and fire protection; switchgear, foundation, pat and moat already exist
- Install 138kV circuit switcher and circuit interrupter at Newtown
- Connect 138kV feeder 38Q05 from Vernon East bus with associated equipment
- Install new GIS module (including 138kV breaker and integral disconnects, bus and supports, surge arrestors, disconnect switch support structure and coupling capacitor potential device) at Vernon substation
- Install new 138kV XLPE feeder via a T-tap of Glendale feeder 38Q05 from Vernon East bus to Newtown 13kV substation (including ground continuity conductor, link boxes, cable joints, and joint support hardware); new cable to be installed in new conduit

Engineering and long lead equipment procurement began in 2023 for this project, and station construction began in early 2024; construction is expected to be completed in 2026. Major equipment requirements for the project include, but are not limited to:

Major Equipment Type	Number to be Purchased
138/27kV transformer with fire protection	1
27kV three phase segregated bus	200 ft
138kV circuit switcher and interrupter	1
GIS module (with 138kV breaker and integral disconnects, bus and supports, surge arrestors, disconnect switch support structure and coupling capacitor potential device)	1
2500 kcmil 138kV XLPE cable	50,688 feet
400 kcmil ground continuity conductor	16,896 feet

Justification Summary:
This project provides load relief for two substations. The first substation it provides load relief for is the Newtown 27kV Substation. The second substation that this project facilitates load relief for is Brownsville Area Substation No. 1.

When this project was initially proposed (and as discussed in the Company response to DPS-16-471 in the last rate case, 22-E-0064), the Newtown 27kV substation was forecasted to be overloaded starting in 2029.

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Newtown net load (MW)	198	213	224	231	234	238	241	246	257	261
Station capability	244									
Reserve/Deficit	46	31	20	13	10	6	3	-2	-13	-17

The most recent forecast in the 2024 Ten-Year Load Relief Program (the LRP) projects that the Newtown 27kV Substation will become overloaded by the end of 2030, one year later than previously projected but well within the ten-year forecast period.

Newtown (w/o expansion)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Borden	130	138	147	152	154	157	160	162	164	167
Sunnyside	72	74	76	78	78	79	80	80	81	81
Total Load	202	212	223	230	232	236	240	242	245	248
Electrification Adjustment	3	5	7	9	12	14	17	20	24	27
Other Adjustments	-3	-5	-5	-6	-9	-13	-10	-11	-14	-15
Non-Wires Solutions (NWS)	0	-5	-5	-5	-5	-5	-5	-5	-5	-5
Net Load	202	207	220	228	230	232	242	246	250	255
Current Capability	244	244	244	244	244	244	244	244	244	244
% of Capability Used	83%	85%	90%	93%	94%	95%	99%	101%	102%	105%
Reserve / Deficit (negative)	42	37	24	16	14	12	2	-2	-6	-11

In addition to addressing this forecasted load constraint at Newtown, the Newtown expansion facilitates interim measures needed to relieve load constraints at the Brownsville No. 1 Area Substation. By adding a 4th supply feeder and transformer at Newtown, "headroom" is created on the other supply feeders that are shared with the Glendale Substation, increasing capacity at Glendale. This increased capacity at Glendale then facilitates a network transfer from Brownsville Area Substation No. 1 to Glendale in 2026, providing incremental load relief at Brownsville No. 1 until the new Gateway Park No. 1 Area Station can be built (expected 2028 in-service date) and additional load transferred from Brownsville No. 1 to Gateway No. 1. The Newtown project has been accelerated to facilitate this contingency solution to the forecasted Brownsville load constraints.

Newtown (w/ expansion - TR4 and 38Q05 ext.)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Borden	130	138	147	152	154	157	160	162	164	167
Sunnyside	72	74	76	78	78	79	80	80	81	81
Total Load	202	212	223	230	232	236	240	242	245	248
Electrification Adjustment	3	5	7	9	12	14	17	20	24	27
Other Adjustments	-3	-5	-5	-6	-9	-13	-10	-11	-14	-15
Non-Wires Solutions (NWS)	0	-5	-5	-5	-5	-5	-5	-5	-5	-5
Net Load	202	207	220	228	230	232	242	246	250	255
Current Capability	244	244	244	244	244	244	244	244	244	244
% of Current Capability Used	83%	85%	90%	93%	94%	95%	99%	101%	102%	105%
Reserve / Deficit (negative) w/o expansion	42	37	24	16	14	12	2	-2	-6	-11
Capability w/expansion			361	361	361	361	361	361	361	361
% of Expanded Capability Used			61%	63%	64%	64%	67%	68%	69%	71%
Reserve / Deficit (negative) w/ expansion			141	133	131	129	119	115	111	106

This project provides load relief in the Vernon to Newtown/Glendale load areas, as a sensible solution to forecasted increases in customer transportation and building electrification, new business load

growth, and the Company's clean energy commitment to meet NYS CLCPA goals, while providing a stop-gap measure until the new Gateway Park No. 1 Area Substation is completed.

Relationship to Broader Company Plans, Initiatives and the NYS Climate Leadership and Community Protection Act

The operational measures and system improvements implemented with this project would be sufficient in addressing load growth across Company networks in central Brooklyn.

By enabling load splits and smaller networks in the Brownsville and Bensonhurst load areas, this program will progressively increase the reliability of the associated networks in both the near and long term. It will help the Company avoid public safety issues related to network failure, customer outages and significant damage to Company equipment. Also, it will protect customers from any issues related to network shutdown.

Resiliency plans: this program will help during problems in the transmission and/or substation which limits the load capacity in the Bensonhurst and Brownsville substations. Once this project is complete, it will be more feasible to transfer out or partially restore the load coming out of Bensonhurst and Brownsville and help minimize the outage impact to customers.

This project is a core investment that enables the Company to continue to provide safe and reliable service, even as the nature of the grid changes. This aligns with Con Edison's strategic objective of providing world-class safety, reliability, and security, while managing the equity challenges of the energy transition.

This project supports the State's achievement of CLCPA and clean energy goals. This aligns with Con Edison's strategic objective to meet economy-wide net-zero GHG emissions in our service territories by 2050.

This project is a climate resilience investment that strengthens utility infrastructure to withstand extreme weather conditions and the physical impacts of climate change. This aligns with Con Edison's strategic objective to increase resilience of our energy infrastructure to adapt to climate change and address other threats and hazards.

2. Supplemental Information

Alternatives

Alternate options considered include operation of 138kV feeders at higher voltages (143kV to 145kV) to increase feeder capabilities, a load transfer to Water Street substation or a load transfer to Bensonhurst No. 2 substation along with the establishment of a fifth transformer. However, these alternatives are short-term solutions and will encounter station capacity of 138kV feeder overloads in 2031. Additionally, operating 138kV feeders at higher voltages will cause stress on the feeders over extended time periods.

Also considered is the installation of cable cooling plants for the feeders that supply Brownsville No.1 and No. 2, which would increase their capacities and mitigate the deficiencies. This alternative would likely require land procurement for the cooling plants themselves and would only solve the feeder rating deficiency; if load growth continued to a point where other equipment within either Brownsville substation was at its maximum capacity, another project would require implementation.

Another alternative is to provide non-wires solutions to defer any traditional infrastructure project to beyond 2040. All system expansion projects will be reviewed for NWS in accordance with the suitability criteria outlined in the Distributed System Platform (DSP). However, future demand

forecasts are subject to change based on actual peak summer load conditions as well as economic trends and are likely to present significant challenges in achieving required customer side load reductions to provide adequate solutions in the face of rapid network load growth. Changes in future forecasts and planning may result in the advancement of addressing system overloads.

Risk of No Action

Risk 1

If this project is not pursued, there is a high risk of overloading the substation equipment at Newtown during peak load conditions. Exceeding the rated capacity of the substation could result in load shedding if contingencies occur during peak loading conditions resulting in customer outages, increasing the risk of equipment failure, and adversely impacting the community served, as well as increasing the potential inability of maintaining reliable system power flow controls, system reliability and resiliency concerns.

Risk 2

An overload on the transmission feeders supplying Brownsville No. 1 and No. 2 Substations is predicted to occur. Many of the Company's Brooklyn Queens substations are near full capacity and do not offer the feasibility of load transfer. In the event the transmission feeders become overloaded, load shedding may be required during peak conditions with service dropped to thousands of customers. The acceleration of this project mitigates the risk of such overloads at Brownsville.

Non-Financial Benefits

Alleviating projected load constraints on the Newtown/Glendale/Vernon feeders will improve reliability and resiliency in an area of New York City that serves many critical loads in a densely populated area where many buildings have elevators and will allow the station to maintain the area substation N-1 reliability design criteria for long term projected load growth in Brooklyn.

Meeting New York's Climate Leadership Community Protection Act (CLCPA) goals will ultimately require the Company to build system capacity for an anticipated increase in load growth. With electrification of the City, as the transition from a carbon economy progresses, the system will need the capacity in the affected networks to accommodate unprecedented load growth. Rapid load growth has the potential to leave the Company in a difficult position to address all the relief and reliability challenges in the future.

Additionally, accelerating the completion of this project addresses interim load constraints at Brownsville.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)

N/A

2. Major financial benefits

This project will enable the Company to address potential transmission equipment overloads. Exceeding the capacity of the substation and transmission feeders could result in load shedding if contingencies occur during peak loading conditions, result in customer outages, and increase the risk of equipment failure and adverse impacts to the community served. The regulatory financial costs of load shedding customers and the cost of replacing transmission/station equipment can be significant to the Company. This project will mitigate the risk of incurring those costs.

3. Basis for estimate

This estimate is based on an order of magnitude estimate of project costs based on a conceptual design and historical costs for similar scopes of work.

Total Direct Costs	**$50,393,123**
Overheads, Escalation, and Contingency	$74,912,500
TOTAL ESTIMATED COST	$125,305,623

Project Risks and Mitigation Plan

Risk 1:
Delays due to resource/support coordination

Mitigation Plan 1:
Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Risk 2:
Material Availability Issues

Mitigation Plan 2:
Engineering will work with Supply Chain to establish a cohesive plan that aligns with vendor lead times. Stay engaged with vendors to ensure lead times are maintained, and adjust the plan as needed if shortages are encountered.

Risk 3:
Unforeseen inclement climate events that will impact planned outages and overall schedule.

Mitigation Plan 3:
Incorporate potential disruptions in the overall planning schedule and identify alternative outage dates, should planned outage dates be cancelled.

Technical Evaluation / Analysis
N/A

Project Relationships (if applicable)
This project supports the establishment of the Gateway Park Area Station in 2028, by increasing capacity to Glendale and enabling interim load relief to Brownsville Area Substation No. 1 in 2026.

3. Funding Detail ($000)

Historic Spend

	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Test Year (O&M Only)*	Forecast 2024
O&M	$0	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	N/A	$0
Capital	$0	$0	$0	$3,246	N/A	$27,200

2025-2029 Request:
Total Request by Year:

	2025	2026 (RY1)	2027 (RY2)	2028 (RY3)	2029
O&M	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	$0
Capital (Total)	$59,300	$66,954	$0	$0	$0
Labor	$10,694	$9,155	$0	$0	$0
M&S	$15,000	$15,667	$0	$0	$0
Contract Svcs.	$15,000	$17,430	$0	$0	$0
Other	$7,000	$10,621	$0	$0	$0
Overheads	$11,606	$14,081	$0	$0	$0

*The test year runs from 10/1/23 to 9/30/24.

Central Operations / Substation Operations
2025-2029

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Parkchester No. 2 TR13 & B/S 13A & 13B Installation	
Project/Program Manager: Roy A. Young	**Project/Program Number (Level 1):** 27724615
Status: ☐ **Initiation/Planning** ☒ **In-Progress (Projects Only)** ☐ **On-going (Programs Only)**	
Estimated Start Date: 2025	**Estimated Date In Service:** 2028
2025-2029 Funding Request ($000) **Capital:** $44,025 **O&M:** $0	

Work Description:
This project is designed to increase the load serving capability at Parkchester No. 2 13kV substation by 81 MW in 2028. This project will install a fourth 138/13kV transformer (Transformer TR13) in an existing empty transformer vault at Parkchester No. 2 and install 138kV tertiary feeder 38X02T from existing 138kV feeder 38X02 (which currently serves as an alternative feed for Transformer TR11) to new Transformer TR13.

Major scopes of work to be completed under this project include:

- Install 138/13.8kV, 65 MVA transformer
- Install 138 kV circuit switcher with ground switch (1)
- Install 138kV circuit interrupter with ground switch (1)
- Install 138kV set of potheads with stand (2)
- Install 138kV solid dielectric feeder from new pothead stand at TR11 to new pothead stand at TR13
- Install 13.8kV phase segregated bus (100ft)
- Install high voltage flex and solid bus with connectors (1 lot)
- Install 13.8kV switchgear sections 13A and 13B
- Install new and modify existing relay protection as necessary
- Install deluge system
- Install new foundations and spill containment for transformer TR13
- Install switchgear pads
- Install new foundations for circuit switcher and pothead stands.

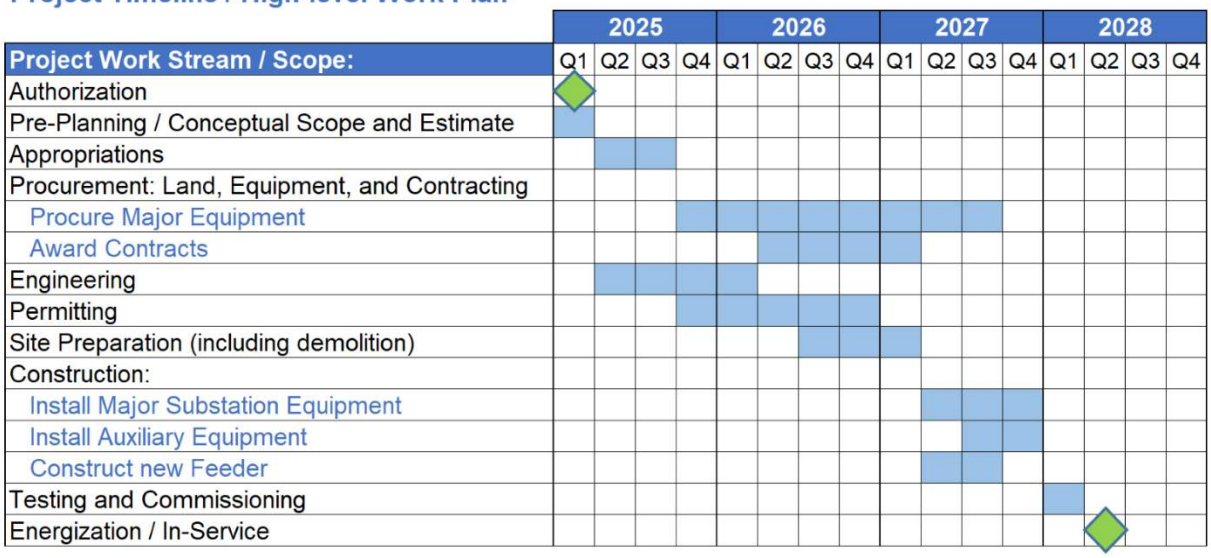
Major or long lead equipment requirements for the project include, but are not limited to:

Major Equipment Type	Number to be Purchased
138/13.8 kV, 65 MVA transformer	1
Secondary Bus (Low Voltage 13kV)	100′

Circuit Switcher with Ground Switch	1
Circuit Interrupter with Ground Switch	1
Switchgear sections 13A and 13B	1

Engineering and long lead equipment procurement will begin in 2025 for this project and construction is expected to begin in 2026 and to be completed in 2028. The estimated timeline to complete the major scopes of work associated with the project is below. This timeline is subject to change at any time, as the Company optimizes the project schedule and incorporates impacts of other projects and system performance.

Project Timeline / High-level Work Plan



Justification Summary:
This project is part of the solution being implemented to accommodate customer electrification at Parkchester No.2 and to reduce related reliability risks. This project will deliver energy to the transportation electrification load expected in the Zerega Avenue hotspot (see Proactive Planning filing (Case # 24-E-0364).

The Company has elected to incorporate a transmission probabilistic reliability assessment (TPRA) method of planning where risk of load drops is quantified to prioritize substation work in the riskiest stations to maintain system reliability. The TPRA model analyzes residual system risk in conjunction with supporting the deterministic planning method. The Company has developed, updated and utilized this model for the past 20 years to prioritize and optimize reliability projects by quantifying load drop risks under different load growth scenarios. TPRA risk analysis shows that the Parkchester No. 2 substation has a high risk of loss of load in the year 2028 and beyond due to projected load and system design. Furthermore, the load forecast uncertainty adds to the risk. Given the potential of fast growth in load and projected load drop risk, it is prudent to add capacity by installing an additional transformer.

The rapid load growth in the Northeast Bronx load areas over the next several years is primarily driven by electrification and associated economic activity in the area. This electrification includes thousands of personal and commercial vehicles in the area that must electrify to meet policy mandates, as well as several specific customer electrification plans. This project will support the projected demand due to

transportation electrification for the Zerega Ave hotspot with anticipated increased demand from electric vehicle charging. Along Zerega Ave, there are over twenty fleet depots and service centers, serving diverse vehicle fleets, including food delivery, logistics, sanitation, school bus and transit, with an estimate of close to 15,000 commercial vehicles. More details are provided in the "Justification Summary" section of the "Proactive Planning - Zerega Avenue Electrification Hotspot" whitepaper included in this filing.

Based on forecasts of load growth in the Northeast Bronx load area, including Zerega Avenue load projections, there is a risk that station capability at Parkchester No. 2 might be over 100% utilized in 2031. This load forecast uncertainty adds to the urgency of adding capacity to the Parkchester No.2 station. However, our probabilistic risk analysis indicates that this project is required in 2028 based on future expected electrification load and associated risk of load drop identified by the probabilistic risk analysis.

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Parkchester No. 2										
Northeast Bronx	117	119	120	121	122	123	123	124	124	125
Radial	45	45	45	45	46	46	47	47	47	47
Total Load	162	164	165	166	168	169	170	171	171	172
Electrification Adjustment	1	2	3	5	6	8	9	11	13	15
Other Adjustments	-7	-8	-9	-10	-10	-10	-9	-10	-11	-11
Net Load	156	158	159	161	164	167	170	172	173	176
Capability	169									
Overload							1	3	4	7

Completion of the proposed work increases the capability of the Parkchester No. 2 substation by 81 MW.

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Parkchester No. 2										
Northeast Bronx	117	119	120	121	122	123	123	124	124	125
Radial	45	45	45	45	46	46	47	47	47	47
Total Load	162	164	165	166	168	169	170	171	171	172
Electrification Adjustment	1	2	3	5	6	8	9	11	13	15
Other Adjustments	-7	-8	-9	-10	-10	-10	-9	-10	-11	-11
Net Load	156	158	159	161	164	167	170	172	173	176
Capability	169			250						

This project will not only aid in transportation electrification but support all loads including building decarbonization and State goals and regulations by ensuring capacity exists for customers to connect to the grid. As filed in the Proactive Planning filing (Case # 24-E-0364), the fourth transformer at Parkchester No.2 would increase area substation capability to accommodate this load and future load growth.

Relationship to Broader Company Plans, Initiatives and the NYS Climate Leadership and Community Protection Act

This project will strengthen the overall transmission system and networks served by the Parkchester No. 2 Substation including Disadvantaged Communities downstream from this project. The Climate Leadership and Community Protection Act (CLCPA) has established greenhouse gas emission reduction limits associated with imported electricity and fossil fuels in New York State, as well as additional climate change goals to include 70% renewable electricity by 2030 and 100% zero emission electricity by 2040. The NYSDEC has coordinated with the NYISO to ensure that compliance with NOx emissions regulations and CLCPA policy objectives would not adversely affect grid reliability.

The operational measures and system improvements implemented with this project would be sufficient in addressing load growth across Company networks in the Bronx.

This project is a core investment that enables the Company to continue to provide safe and reliable service, even as the nature of the grid changes. This aligns with Con Edison's strategic objective of providing world-class safety, reliability, and security, while managing the equity challenges of the energy transition.

This project was also included in the Company's Proactive Planning proceeding (Case # 24-E-0364) Urgent Projects Filing to support grid infrastructure needs for transportation and building electrification. If funding is granted in the Proactive Planning proceeding, the capital requests in this Rate Case proceeding will be adjusted as needed.

2. Supplemental Information

Alternatives

Another alternative considered was to rely upon Customer Sided Solutions (CSS) to mitigate any future area station capacity deficiencies. Based on the magnitude of load relief required to address the overload constraints in the Bronx under a limited time frame, it has been assessed that CSS are not a viable option. There is no known contingency plan other than to pursue the identified traditional solution should this alternative be pursued and prove unable to meet the projected deficits.

Risk of No Action

Overloads on the area substation transformers supplying the Parkchester No. 1 Substation is predicted to occur without additional capacity. Many of Con Edison's Brooklyn Queens substations are near full capacity and do not offer the feasibility of load transfer. In the event the transmission feeders or area substation overload, load shedding may be required during peak conditions which would cause thousands of customers to encounter service outages.

Without pursuing the project, the Company networks will encounter the potential inability to maintain reliable system power flow controls, system reliability and resiliency concerns and/or possible customer outages for an extended period during peak load conditions.

More details on the impacts of delays are available in the "Risk of No Action" section of the "Zerega

Avenue Electrification Hotspot" Whitepaper

Non-Financial Benefits

This project will provide the necessary reliability in both the Northeast Bronx and Southeast Bronx networks, densely populated areas of New York City that serve many critical loads (e.g., transportation hubs, and hospitals).

- The non-financial benefits of enabling electrification in the Zerega Avenue hotspot are detailed in the "Non-Financial Benefits" section of the "Zerega Avenue Electrification Hotspot" Whitepaper (Appendix Exhibit A).
- This project will also add the capacity needed to support transportation and building electrification, which will improve air quality, noise pollution, and reduce greenhouse gas emissions. Based on Con Edison's internal analysis, by 2040 this project will support charging light-, medium-, and heavy-duty vehicles and electrification of heating systems to avoid 279 thousand tons of carbon dioxide equivalent (CO2e) that year, with a total avoided emissions of 3,030 thousand CO2e from the in-service date through 2040, and even more in the years beyond.

- The grid readiness resulting from this project will signal to customers looking to electrify in compliance with policy mandates that the grid is ready to accommodate their load requests without delaying their plans.

This project will also strengthen relationships with our customers and communities. By proactively building out our grid to be ready for new loads, we are increasing customer trust and a better customer experience to enable a smoother and expedited new business process.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis (if required)
N/A

2. Major financial benefits

This project will enable the Company to address potential transmission equipment overloads. Exceeding the capacity of the substation and transmission feeders could result in load shedding if contingencies occur during peak loading conditions, result in customer outages, and increase the risk of equipment failure and adverse impacts to the community served. The regulatory financial costs of load shedding customers and the cost of replacing transmission/station equipment can be significant to the Company. This project will mitigate the risk of incurring those costs.

3. Basis for estimate

This estimate is an order of magnitude estimate of project costs based on a conceptual design and historical costs for similar scopes of work. High-level estimates of total costs, by primary spend category, are shown below, including escalation, overheads, and contingency.

	Estimated Direct Costs	*Esc., OH, & Other Loading*[1]	*Estimated Total*	*% of Total*
01-Labor	$ 7,033,761	$ 11,599,290	$ 18,633,051	42.0%
02-MSH	$ 9,785,163	$ 9,788,405	$19,573,568	44.2%
03-Cont Svcs	$ 1,096,503	$ 1,096,867	$2,193,370	5.0%
09-Other	$ 1,943,828	$ 1,944,472	$3,888,300	8.8%
Total	**$19,859,256**	**$24,429,032**	**$44,288,288**	

[1]Includes: Escalation (31%), CE OH (13.25%), A&S (2.53%), PT&P (39.35%), AFDC (2.32%), and Contingency (23%)

Project Risks and Mitigation Plan
Risk 1:
In 2028, there is a potential 6 MW capacity deficit if electrification loads materialize quicker than forecasted. A risk would be that a viable solution (e.g., CSS) can't be determined and called upon in time to meet this need.

Mitigation Plan 1:
The Company will review in advance and confirm that a solution such as CSS (energy storage) will be available in the region and on standby to support capacity deficit need of 6 MW if the load materializes

Risk 2:
Risk of overbuilding or underbuilding

Mitigation Plan 2:
This project avoids underbuilding by planning in accordance with load projections from the granular load study that ramp up to support the full electrification scenario. Three mitigating factors counteract the risk of overbuilding: (1) the assets immediately improve system reliability and resiliency, (2) the assets can create capacity for other non-transportation or building electrification loads, and (3) if the electrification load does not materialize, the transformer could be removed and used to support new capacity elsewhere on the system.

Risk 3:
Uncertainty of timing, location, and magnitude (i.e., appropriate sizing) of load materialization.

Mitigation Plan 3:
While there is some uncertainty around the exact timing of customer electrification and which customer will electrify at any given exact time, the general timeframe for load increases across the area is well known given existing policies. The Company's granular EV load projection analysis reveals the locations and magnitude of EV adoption. This analysis links directly to State policy objectives, considers available funding, and was corroborated by extensive outreach to fleet customers.

- Timing: As discussed in the Justification section above, policy objectives and specific customer plans dictate electrification timelines, which the Company uses to mitigate the risk of being late. The risk of being too early is minimal due to the project plans already identified in the region and the high confidence in the load materializing. Furthermore, once transformers are installed, they will increase system reliability. All this work will signal to the customers in this region of the Bronx – school bus fleet operators, the Department of Sanitation, transit buses, and utility fleets – that the grid is ready to accommodate their electrification without long lead times for utility construction.
- Locations: Depot locations in this region are known and not expected to change over time given restricted land availability in the area. Furthermore, given the density of vehicles expected to electrify and need access to charging in this hotspot, the new infrastructure built as part of this project could serve multiple customers along the feeder run. Therefore, the fact that the Company does not know which precise location will electrify first is not a risk but rather accounted for by constructing this proactive solution.
- Magnitude: The Company's granular EV load model projected the charging needs of each type of vehicle to determine the magnitude of load needed for transportation electrification.

Technical Evaluation / Analysis
N/A

Project Relationships (if applicable)
This project is related to Parkchester No. 1 5th Transformer 9S and Supply Feeder 38X05 project.

This project is related to the Zerega Avenue Electrification Hotspot project. Area substation work at Parkchester No.2 is required to create capacity to support the distribution infrastructure needed for the electrification loads within the Zerega hotspot.

This project was also included in the Company's Proactive Planning proceeding (Case # 24-E-0364) Urgent Projects Filing to support grid infrastructure needs for transportation and building electrification.

3. Funding Detail ($000)

Historic Spend

	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Test Year* (O&M Only)	Forecast 2024
O&M	$0	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	N/A	$0
Capital	$0	$0	$0	$0	N/A	$0

2025-2029 Request:

Total Request by Year:

	2025	2026 (RY1)	2027 (RY2)	2028 (RY3)	2029
O&M	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	$0
Capital (Total)	$7,500	$11,175	$12,675	$12,675	$0
Labor	$1,050	$1,565	$2,788	$2,788	$0
M&S	$2,925	$4,358	$1,559	$1,559	$0
Contract Svcs.	$1,200	$1,788	$4,770	$4,770	$0
Other	$274	$427	$0	$0	$0
Overheads	$2,051	$3,037	$3,558	$3,558	$0

*The test year runs from 10/1/2023 to 9/30/2024

Central Operations / Substation Operations

2025-2029

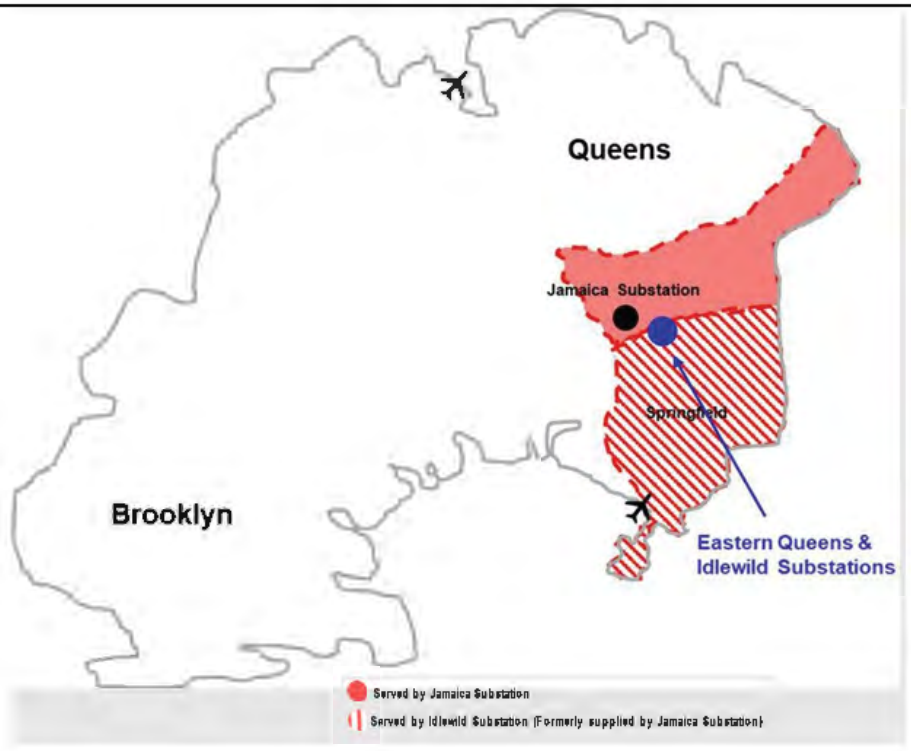
1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Establish Idlewild Area Substation	
Project/Program Manager: John Mccoy	**Project/Program Number (Level 1):** 26402978
Status: ☐ **Initiation/Planning** ☒ **In-Progress (Projects Only)** ☐ **On-going (Programs Only)**	
Estimated Start Date: 2023	**Estimated Date In Service:** 2028
2025-2029 Funding Request ($000) **Capital:** $355,067 **O&M:** $0	

Work Description:

The construction of the Idlewild Area Substation is one part of several projects that, combined, will provide load relief to the Jamaica 27 kV Distribution Area Substation. The overall project will consist of three parts: 1. Building a new 138 kV transmission substation, the Eastern Queens 138 kV Transmission Substation ("Eastern Queens"), which will supply the new Idlewild 27 kV Distribution Area Substation; 2. Building the new Idlewild 27 kV Distribution Area Substation ("Idlewild"); and 3. Transferring 170 MW from the Jamaica Network to the new Idlewild 27 kV Distribution Area Substation, thereby creating the new Springfield Network ("Springfield"). The in-service date for the Eastern Queens Transmission Substation is April 2028, the in-service date for the Idlewild Distribution Area Substation is May 2028, and the Springfield Network in-service date will be May 2028.

A petition for the authorization and cost recovery of this three-part project to provide load relief to the Jamaica network was submitted by separate petition to the Commission in August 2023. In January 2024 the Commission issued an Order that authorized interim cost recovery through a surcharge until the Commission addresses the Company's next major electric base rate proceeding. (Case 22-E-0064 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, *Order Addressing Cost Recovery of Idlewild Project* (Issued and Effective January 19, 2024)). The total estimated cost of the overall project included in the petition for all three projects was approximately $1.2 billion: approximately $592 million for the Eastern Queens Transmission Substation; approximately $380 million for the Idlewild Distribution Area Substation; and approximately $242 million for other electric facilities, e.g., feeders for the new Springfield Network.



The Idlewild Area Substation will be co-located with the Eastern Queens Transmission Substation on a vacant parcel of Company-owned land in Jamaica, Queens. Idlewild will be an indoor 27 kV Distribution Area Substation, arranged in a double synchronous (SYN) bus configuration. It will include four 93 MVA, 138 kV/27 kV transformers, with provisions for an additional transformer in the future. The substation will include up to fifty feeder positions, including seventeen new 27kV feeders to supply the new Springfield Network.

For the first phase of the project, the Company will install a 138 kV Phase Angle Regulator and a 138 kV/27 kV Transformer (Phase 1). This equipment will connect to 138 kV feeder 901 L/M as well as extend and connect to existing 27 kV distribution feeders. This work is required in the event the Company encounters additional forecasted load growth sooner than 2028 or unforeseen delays with the Project and will enable emergency power injection to the 27 kV Jamaica Network. This project provides for an emergency means to supply the Jamaica network with an additional resource to sustain service to the area. As options are very limited to supply an emergency resource due to the geographical location of the network and vast size of the network, this work is required.

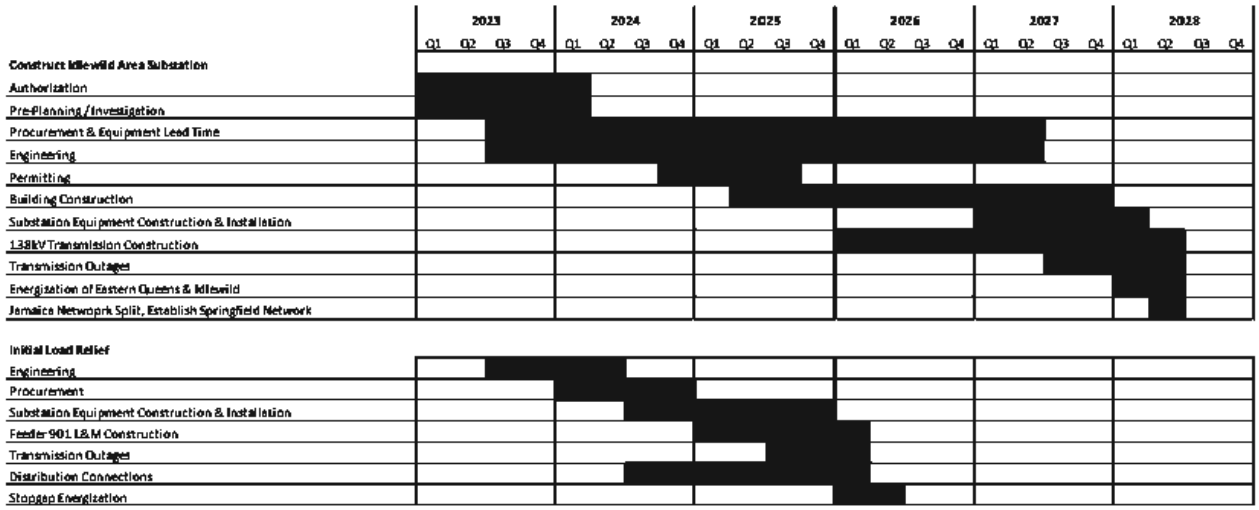
The major scopes of work to be completed to establish the Idlewild Area Substation include:

- Install 138kV PAR and 138kV/27kV Transformer (Phase 1) to ensure continuous support of Jamaica load
- Complete distribution connections (Phase 1)
- Complete site preparation at Company-owned parcel of land
- Construct building
- Install substation equipment
- Construct Feeder 901 L&M
- Construct 138kV transmission to Idlewild

Engineering and long lead equipment procurement began in 2023 for this project and station construction is expected to begin in the second quarter of 2025. Long lead equipment requirements for the Project includes, but is not limited to:

Major Equipment Type	Number to be Purchased
138/27kV Transformers	4
30 MVAR Capacitor banks	2
27kV Switchgear	5 sections
High Voltage Test Set	1
Phase Angle Regulator	1

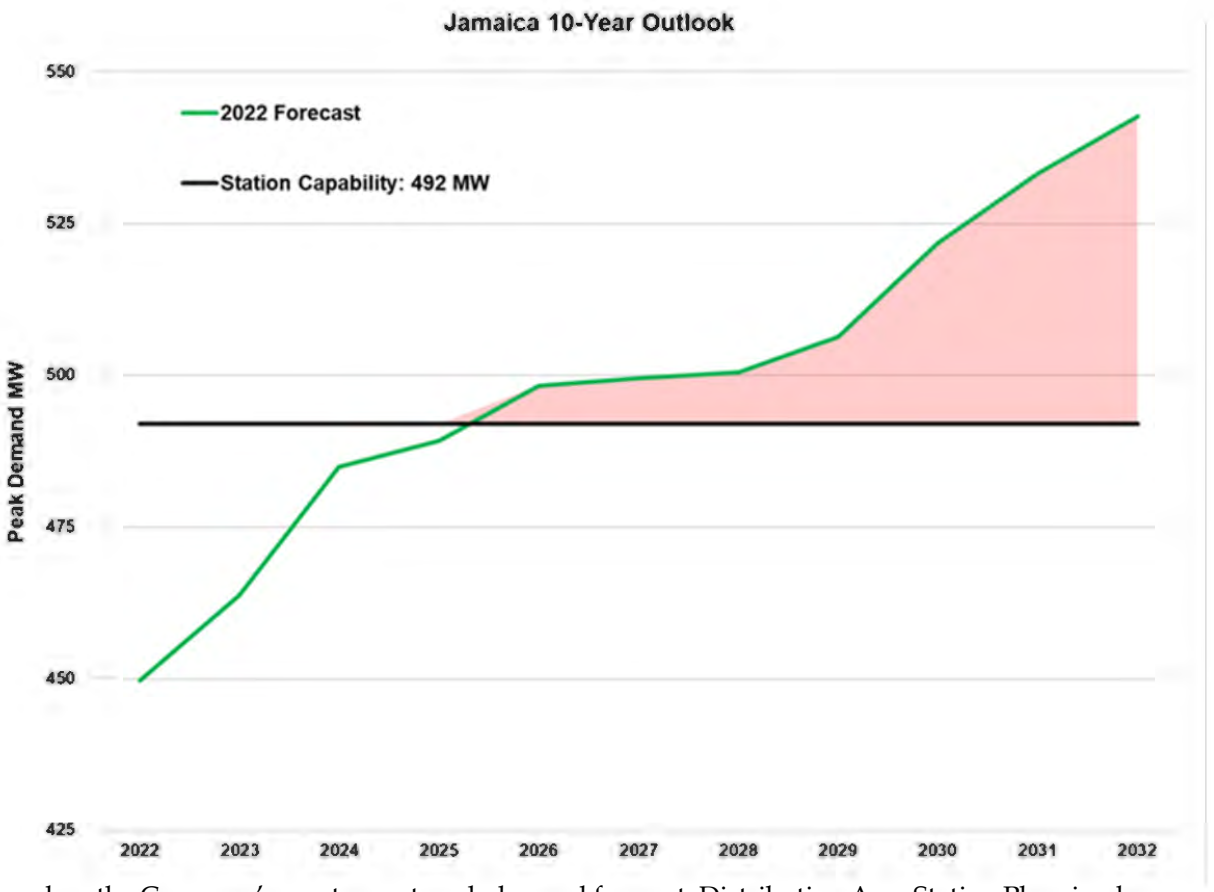
The estimated timeline to complete construction of the Idlewild Area Substation and the schedule for work associated with the Phase 1 initial load relief (described above) are shown below. These timelines are subject to change at any time, as the Company optimizes the project schedule and incorporates impacts of other projects and system performance.



Justification Summary:
To identify near-term load relief needs, the Company used a ten-year forecast of peak load conditions and compared those projections to the substation and network capabilities. Solutions identified to alleviate forecasted overloads are designed to do so on a ten-year basis and the Company prioritized solutions that are both technically viable and least cost. The timing of investment for these solutions is based on their required lead times.

The Jamaica Network is Con Edison's highest peak demand network, forecasted at 472 MW for summer 2025. It is also one of the largest geographically, and one of the most isolated, being generally further away from other Company transmission and distribution area substations. The Network serves over 162,000 customers, including John F. Kennedy International Airport ("JFK Airport"), which is the country's sixth busiest airport with about 26.9 million passengers annually, the Long Island Railroad Jamaica Station, which is the country's third busiest train station, and four major MTA bus depots with approximately 700 buses that the MTA is planning to switch to electric battery powered vehicles.

The Company's current peak demand forecast for the Jamaica Network is as follows:



Based on the Company's most recent peak demand forecast, Distribution Area Station Planning has determined that the Jamaica 27 kV Distribution Area Substation will exceed its design capability in 2026. Over the last few forecasting cycles, the peak demand forecast for the Jamaica Network has generally increased year over year. Higher weather-adjusted peak demand experienced in the summer of 2023 was a key driver of the most recent forecast increase. Electrification of vehicles and non-heating appliances will continue to contribute to peak demand in the near term.

Con Edison's November 2024 load forecast, combined with distribution area station planning design criteria, shows that the peak demand at design conditions for the Jamaica Distribution Area Substation is projected to equal its design capability of 492 MW as early as 2026 (see below). Further, the summer peak customer demand, which is weather normalized to a design Temperature Variable of 86,7 will equal the substation's design capability limit by 2026 and 2027 and exceed the design capability limit in 2028. The exceedance is driven by a significant increase in electric demand due to vehicle electrification and economic growth. In particular, the forecast includes electrification related to medium and heavy-duty vehicles, such as the buses, cargo vans, and trucks associated with the logistic and shipping operations prevalent in the Jamaica Network, and the $14 billion redevelopment program at JFK Airport.

With the Company's latest forecast, Jamaica is projected to be overloaded beginning in 2026.

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Jamaica										
Jamaica	468	483	491	497	503	506	516	518	519	521
Electrification Adjustment	9	16	21	25	34	45	57	69	82	96
Other Adjustments	-5	-5	-7	-8	-7	-2	-3	-3	-3	-3
Net Load	472	494	505	514	530	549	570	584	598	614
Capability	492									
Deficits		2	13	22	38	57	78	92	106	122

Based on the forecast, to avoid overloads at the Jamaica 27 kV Distribution Area Substation, the Company must pursue Non-Wires Solutions to provide load relief for Jamaica 27 kV Distribution Area Substation until 2028, when the long-term load relief solution of Eastern Queens, Idlewild and Springfield Network can be placed in service. To allow adequate time to build the new Eastern Queens station while maintaining reliability, the Company is pursuing a Non-Wires Solution to reduce peak load in the Jamaica Network for 2026 and 2027. The Company has consulted with Department Staff as required for Non-Wires Solutions, issued a request for proposals, received vendor proposals, committed funding, and filed notification of this Non-Wires Solutions Portfolio on March 16, 2023 in Case 19-E-0065.

Following energization of the Idlewild Area Substation in 2028, the Company plans to transfer approximately 170 MW from the Jamaica Network to a new network, Springfield, served by the Idlewild station.

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Idlewild										
Springfield				170	172	173	176	177	178	178
Electrification Adjustment				9	12	15	19	24	28	33
Other Adjustments				-3	-3	0	-1	-1	-1	-1
Net Load				176	181	188	194	200	205	210
Capability				358						

Following this load transfer in 2028, capability usage at Jamaica will return to acceptable levels.

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Jamaica										
Jamaica	468	483	491	327	331	333	340	341	341	343
Electrification Adjustment	9	16	21	16	22	30	38	45	54	63
Other Adjustments	-5	-5	-7	-5	-4	-2	-2	-2	-2	-2
Additional NWS		-2	-13							
Net Load	472	492	492	338	349	361	376	384	393	404
Capability	492									

Relationship to Broader Company Plans, Initiatives and the NYS Climate Leadership and Community Protection Act

The Company expects general increases in load, electrification of vehicles and electrification of non-heating appliances. Load projections in the 2024 – 2033 Ten Year Load Relief Program indicate that the Queens networks will encounter increasing overloads in ensuing years, with the Jamaica 27 kV Distribution Area Substation exceeding its station design capability. To address reliability design criteria and build in resiliency for various contingency events, the new Eastern Queens 138 kV Transmission Substation and the new Idlewild 27kV Area Substation will be placed into service by 2028. These projects will improve the reliability of the Jamaica and new Springfield Networks by allowing the Company to reduce network sizes and will establish feasible resiliency options for various contingency events, which are not available with the existing distribution system design. The new 138 kV transmission substation will also provide potential points of interconnection for energy storage systems.

By enabling load splits and smaller distribution networks in the Jamaica and Corona Transmission Load Areas, this program will progressively increase the reliability of the associated networks in both the near and long term. The Project will alleviate issues which limits the load capacity in the Jamaica and Corona 27 kV Distribution Area Substations. Once the project is in service, it will be more feasible to transfer out or partially restore the load emanating out of Jamaica and Corona No. 1 and No. 2 27 kV Distribution Area Substations, minimizing the impact of outages to customers. It will help the Company avoid public safety issues related to network failures and significant damage to Company equipment.

The Project will facilitate achievement of State and City emissions goals by facilitating electrification. The Project will enable 170 MW of future customer growth in the Jamaica Network and 176 MW of future customer growth in the Springfield Network for electric vehicle adaptation, electrification of hot water heaters, stovetops, ovens, and clothes dryers in the summer, and new business. Over the long run, as electrification of heating becomes more mainstream, the Project will also enable the additional margin to support progress towards New York State's clean energy future goals. Accordingly, this Project will enable achievement of CLCPA goals, not just by enabling electrification, but because it will benefit disadvantaged communities through improved reliability. This aligns with Con Edison's strategic objective to meet economy-wide net-zero GHG emissions in our service territories by 2050.

The operational measures and system improvements implemented with this project would be sufficient in addressing potential overloads associated with load growth across Company networks in Queens.

This project is a core investment that enables the Company to continue to provide safe and reliable service, even as the nature of the grid changes. This aligns with Con Edison's strategic objective of providing world-class safety, reliability, and security, while managing the equity challenges of the energy transition.

2. Supplemental Information

Alternatives
Alternative 1: An alternative solution is to rely on Non-Wires Solutions to mitigate any future substation capacity exceedances. Energy efficiency, and other Non-Wires Solutions can provide cost-beneficial solutions across different customer segments that may help defer traditional solutions.
Reason for rejection: Based on the magnitude of load relief required in the Jamaica Network, the Company has determined that Non-Wires Solutions are most appropriately suited as short-term solutions until Eastern Queens and Idlewild can be built. Therefore, there is no known contingency plan other than to pursue the identified traditional solution.

Alternative 2: An alternative solution is to conduct load transfers.
Reason for rejection: Overloads at the Jamaica 27 kV Distribution Area Substation are predicted to occur in the current planning horizon (i.e., 2026). There is insufficient capacity at any adjacent Queens 27 kV Distribution Area Substations to make load transfer feasible. Corona No. 1, Corona No. 2, and Brownsville No. 2 (Richmond Hill network) are the only 27 kV Distribution Area Substations geographically abutting the Jamaica network.

Brownsville No. 2 27 kV Distribution Area Substation is constrained by the Farragut to Brownsville 138 kV sub-transmission feeders, which will require load relief in the 10-year planning horizon. The establishment of Gateway Park 27 kV Distribution Area Substation, to be supplied by four 138 kV feeders from the new 345 kV Brooklyn Clean Energy Hub, will provide relief for the Farragut to Brownsville 138 kV sub-transmission feeders.

Although the Corona No. 1 currently has capacity of about 93 MW to accept some load from the Jamaica 27 kV Distribution Area Substation, such a transfer is not feasible. The cost is high, and the work is complex as the required feeder work would have to cross or bypass multiple natural and manmade barriers including the North Grand Central Expressway, the Long Island Expressway, and multiple parks. The transfer would require running feeder extensions from the Flushing (07Q) network through the Rego Park (03Q) network into the Jamaica (05Q) network. These extensions would dramatically reduce the reliability of the Flushing (07Q) network and could result in overloading the existing 07Q feeders. The load transfer would require the creation of a subnetwork involving the separation and creation of a network fringe which reduces the secondary reliability of the area.

The Corona No. 2 27 kV Distribution Area Substation has a very limited margin to accept a load transfer, as only 14 MW of capacity is available at the end of the 10-year planning horizon. A transfer to Corona No. 2 would only move it closer to exceeding its design capability and require the Company to move up planned work for Corona No. 2 within the 10-year planning horizon.

Alternative 3: An alternative solution is to increase Jamaica bus uprates.
Reason for rejection: Bus uprates require replacing the existing 27 kV bus with a higher capacity bus throughout the majority of the substation and within the existing physical space. The scope requires removal and replacement of bus from each transformer and includes the distribution load bus sections.

This work requires sequential outages of each transformer and distribution bus section for approximately two months in duration each. The Jamaica 27 kV Distribution Area Substation topology is unique in that many distribution load bus sections contain six distribution feeders each. During each scheduled outage to replace the bus duct, a station supply transformer and the associated distribution feeders are required to be out of service. For most of the scheduled outages, this means six distribution feeders will be out of service for the duration of the upgrade. During these long periods of time, there is no way to recall the equipment to service should any additional station contingency or unforeseen weather event occur. The Company evaluated the bus uprates based on the 2021 forecast when the forecasted need arose in 2028 first arose. The 2022 forecast demonstrated that the Jamaica 27 kV Distribution Area Substation will exceed its design capability in 2026. As a result, given the five-year schedule to complete the work and the complexity executing the bus uprate work, the Company has decided to pursue a Non-Wires Solution Portfolio to provide load relief while the Project is constructed.

Risk of No Action

Risk 1: In the event the Jamaica 27 kV Distribution Area Substation becomes overloaded, load shedding may be required during peak load conditions in the Jamaica Network (the Company's largest network in both customers and peak usage) which could cause thousands of customers to experience service outages.

Risk 2: An additional risk in not pursuing the establishment of the Eastern Queens Transmission Station is potential impacts to critical customers (e.g., JFK Airport, LIRR Jamaica Station) served by the Jamaica 27 kV Distribution Area Substation. Without pursuing the project, the Jamaica Network could be unable to maintain reliable system power flow controls and system reliability I addition to causing resiliency concerns and/or possible customer outages for an extended period during peak load conditions.

Non-Financial Benefits

- Provide necessary reliability and resiliency in an area of New York City that serves many critical loads (e.g., airports, transportation hubs, and hospitals) in a densely populated area where many buildings have elevators and various equipment loads.
- Provide transmission capacity to enable local growth and facilitate the integration of future bulk renewable energy sources.

- Create points of interconnection (POIs) on the transmission system that do not currently exist, which could be used by third party generators seeking to supply clean energy to the Con Edison and New York State Transmission Systems.
- Provide POIs for energy storage.
- Improve network reliability index ratings compared to the present Jamaica Network, stemming from fewer megawatts transmitted over shorter feeder distances, fewer feeder components or possible points of failure, and less stress on the components.
- Provide for future load growth and electrification, including:
    - The transfer will allow the future creation of dedicated cubicles to transfer the JFK Airport load. This will avoid unnecessary outages involving network transformers or other points of potential failure, thereby increasing the reliability for JFK. These dedicated feeders will also allow for future expansion of JFK load without any need for additional infrastructure investments for load relief.
    - The non-network load area being transferred to the new Distribution Area Substation will experience large load increases due to climate change electrification and increased use of EV. The extra capacity created will enable future expansion by using these non-network feeders to supply multibanks that can be expanded to create localized grids with improved reliability.
    - Feeders containing 4 kV stations that also supply a 27 kV secondary network are known to cause load shifts on the 27 kV grid as the load transfers to nearby feeders after feeder contingencies. The large 27 kV network load remaining in Jamaica will benefit from removing this risk factor. When a 27 kV feeder that is connected to the 4 kV grid fails, the load gets transferred via 4 kV interties to other 4 kV unit stations and their 27 kV supply feeders. Additionally, the secondary network redistributes the network load to other supplying feeders. This can cause substantial amounts of load to be transferred to related feeders. This sudden increase in load can stress the remaining in-service 27 kV feeders supplying the load area and cause feeders to trip during multiple contingency events. The new Springfield network will supply mostly 4 kV load with limited 27 kV network load while the remaining Jamaica network will have minimum 4 kV station load, reducing risk to both networks.
    - The existing Jamaica 27 kV feeders are large and heavily loaded in terms of MW per feeder. The creation of the new network will divide the load area into two distinct networks, each with shorter feeder runs that carry fewer MWs. The secondary benefit of this will be a reduction in the network reliability index rating of the Jamaica and Springfield Networks.
    - No new secondary network fringe or boundary will be created since the load transferred is non network and the small network load pocket of 12 MWs is nested within the Jamaica 4 kV grid. This will avoid creating new weaknesses in the load areas being transferred since the new work does not change existing secondary network boundaries. Normally, new network boundaries require additional reinforcement to maintain reliability.
    - This project will also improve the resiliency of the Jamaica and Springfield Network and prepare them for electrification. Instead of solving overloads by upgrading cable with lesser reliability improvements, this program will solve future primary overloads while greatly increasing the reliability of the network by introducing new feeders.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)
N/A

2. Major financial benefits
N/A

3. Basis for estimate

The funding request is based on an initial order of magnitude estimate based on the scope of work and major equipment described above.

DESCRIPTION IDLEWILD NEW 27KV AREA SUBSTATION PH-1	
Labor	**$ 110,753,584**
Labor - Substation Construction	$ 100,202,229
Labor - Transmission	$ 10,551,355
Substation Equipment:	**$ 125,919,765**
93 MVA Transformers	$ 35,881,928
27kV Switchgear and Relays	$ 68,751,124
Cap Banks, Pothead Stands, Disconnect Switches, Surge Arrestorsand Other Electrical Equipment	$ 6,328,965
PAR Phase Angle Regulator Unit	$ 14,957,748
Transmission Equipment:	**$ 2,820,000**
Cable, Joints	$ 2,820,000
Contract Services	**$ 118,837,651**
Substation Contract Services - Building, Transformer Vaults, Fire Suppression, Misc Support Structures	$ 102,156,688
Transmission Contract Services - Civil, Conduit Install and Cable Installation	$ 16,680,963
Other Services	**$ 21,796,000**
Other - Engineering, Technical, Testing, Environmental, Remediation, Equipment Rentals, Guard Services and Support Services	$21,796,000.00
Grand Total	**$ 380,127,000**

Project Risks and Mitigation Plan

Risk 1:
Delays due to resource/support coordination. There are a large number of projects to expand the electric distribution system that may strain existing resources.

Mitigation Plan 1:
Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts. Expand hiring and increase the number of employees over the next few years to be able to handle the increased flow of work.

Risk 2:
Material Availability Issues

Mitigation Plan 2:
Engineering will work with Supply Chain to establish a cohesive plan that aligns with vendor lead times. Stay engaged with vendors to ensure lead times are maintained, and adjust the plan as needed if shortages are encountered.

Risk 3:
One major risk is for load to increase faster than forecasted which will cause load to exceed equipment ratings before completion of projects to de-load such equipment.

Mitigation Plan 3:
Start projects early and on a longer cycle to allow for acceleration if the need arises.

Technical Evaluation / Analysis

N/A

Project Relationships (if applicable)
There is a load transfer project associated with the establishment of the Idlewild Area Substation. Approximately 170MW will be transferred from the Jamaica Network with the new Idlewild 27kV Distribution Area Substation (along with the creation of a new Springfield Network). Construction of the Eastern Queens Transmission Switching Station is also required to support this load transfer and relieve the constraint at the Jamaica area substation.

3. Funding Detail ($000)

Historic Spend

	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Test Year* (O&M Only)	Forecast 2024
O&M	$0	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	N/A	$0
Capital	$0	$0	$0	$300	N/A	$25,060

2025-2029 Request:
Total Request by Year:

	2025	2026 (RY1)	2027 (RY2)	2028 (RY3)	2029
O&M	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	$0
Capital (Total)	$80,950	$117,600	$77,000	$79,517	$0
Labor	$9,714	$22,248	$12,350	$7,043	$0
M&S	$18,619	$36,598	$17,319	$30,459	$0
Contract Svcs.	$35,771	$24,725	$17,627	$24,000	$0
Other	$2,737	$5,863	$3,000	$3,000	$0
Overheads	$14,110	$28,166	$26,704	$15,014	$0

*The test year runs from 10/1/2023 to 9/30/2024

Central Operations / Substation Operations
2025-2029

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Brownsville Area Load Relief – Establish Gateway Park No. 1	
Project/Program Manager: Antonio Corchado	**Project/Program Number (Level 1):** 25551794
Status: ☐ **Initiation/Planning** ☐ **In-Progress (Projects Only)** ☒ **On-going (Programs Only)**	
Estimated Start Date: 2023	**Estimated Date In Service:** 2028
2025-2029 Funding Request ($000) **Capital:** $1,289,190 **O&M:** $0	

Work Description:
This project is part of a Company program designed to alleviate forecasted overloads on the 138kV feeders supplying the Brownsville Area Substations. The Company first identified the need for a new substation to provide relief for the Brownsville substation in 2014, but prior load forecasts showed the Brooklyn Queens Demand Management (BQDM) program deferring the need for the new station until 2032. More recent forecasts, however, show significant, near-term load growth in the area (including adoption of electric vehicles and electric heating) indicate that a new station is needed by 2028.

Because of the risk that subsequent load growth in the area could create reliability issues before the long-term solution can be implemented, the planned Company program includes both interim solutions and a long-term solution, planned for implementation beginning in 2024 and with the final, long-term solution implemented in 2028.

Interim solutions identified to address Brownsville feeder overloads include:

- 2024-2025: Operate the Farragut to Brownsville 138 kV feeders at 143 kV and 0.97 Power Factor.
- 2024-2033: Install/maintain alternate utility and customer side solutions for BQDM.
- 2024: Transfer Metropolitan Transportation Authority (MTA) transit rectifier station (HTV70S1) from Crown Heights (3B) to Flatbush (4B), reducing Brownsville feeder load by approximately 2 MW. (completed)
- 2025: Transfer MTA transit rectifier station (HTV2337) and Starr 4kV Autoloop from Ridgewood (SB) to Maspeth (6Q), reducing feeder load by approximately 4 MW.
- 2026: Install a fourth transformer at Newtown and a new 138kV sub-transmission feeder (38Q05) from the Vernon substation to the Newtown Substation (making capacity available on the 138 kV Vernon sub-transmission feeders supplying Glendale, Newtown & Amtrak) and transfer 60 MW from Brownsville No. 1 to Glendale.

The long-term solution to providing Brownsville load relief under this program is to construct the new Gateway Park Area Substation, to be supplied by the new Brooklyn Clean Energy Hub via four

new 138kV sub-transmission feeders. The capital projects involved in completing the Gateway Park Area Substation and alleviating forecasted Brownsville overloads include:

- 2028: Establish Gateway Park Area Substation No. 1
- 2028: Split Crown Heights network and transfer 120 MW from Brownsville No. 1 to Gateway Park No. 1

This project is part of the long-term solution for load relief on the feeders supplying the Brownsville Area Substations and is planned to be energized in Summer 2028. The new Gateway Park No. 1 substation will be an indoor 27kV area substation that will be arranged in a double SYN bus configuration and with an initial build of four 138/27kV transformer banks (with provisions for expansion to five transformer banks). The station will be supplied from the 345kV Brooklyn Energy Hub, will add resiliency to the network, and provide additional sub-transmission capacity to mitigate design capability deficiencies in the Bensonhurst and Brownsville load areas to meet projected load growth.

Initial property searches for a suitable property in southeast Brooklyn began in 2022 and the Company completed its acquisition of the selected property, at 789 91st Street in Brooklyn, in December 2023.



The purchased property is about 1.05 acres (45,990 sq. ft.) zoned M1-1, previously used as a multi-tenant industrial warehouse. The Company proposes to use an estimated 45,910 sq. ft. of the property for the proposed substation.

The property is in the process of being demolished and foundation work for the new structure is expected to commence early in 2025. All site and substation designs will meet all current design standards including those specified in the Con Edison Climate Change Planning and Design Guidelines that have been established to proactively address risks from projected climate changes, such as flood levels of FEMA 100-yr floods plus five feet (also referred to as 'FEMA+5').

The major scopes of work remaining to be completed as part of this project include design and construction of the following project phases:

- Property Acquisition (completed)
- Engineering Package Development (underway)
- Site Demolition & Remediation (underway)
- Pour Foundation
- Erect Building Structure
- Complete Building Interiors (Mechanical, Electrical & Plumbing)
- Procure and Install Substation Equipment
- Complete sub-transmission feeder Installation
- Complete substation Terminations and Commissioning

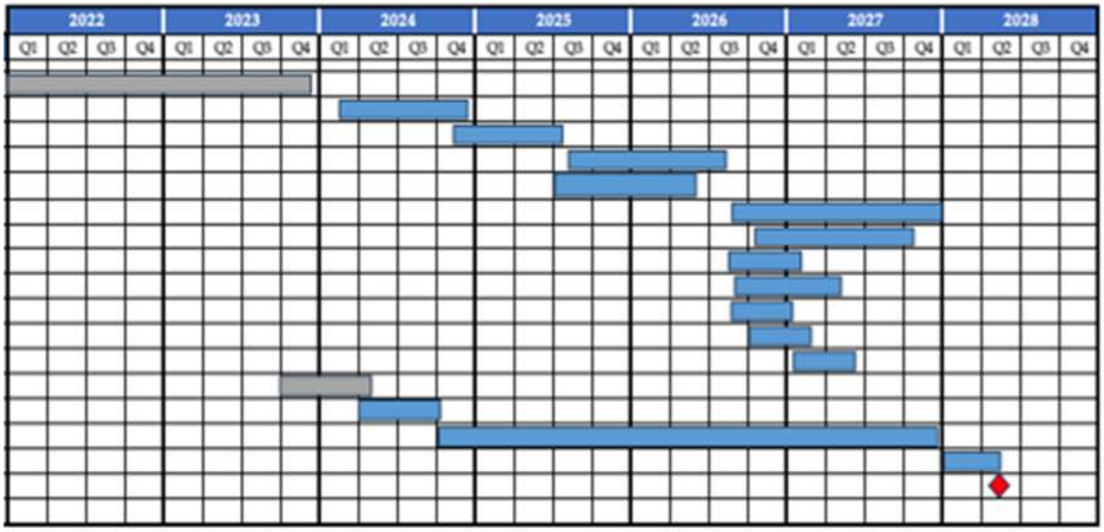
Engineering and long lead equipment procurement began in 2023 for this project and station construction is expected to begin in late 2024. Remaining major or long lead equipment purchases for this project include, but are not limited to:

Major Equipment Type	Number to be Purchased	Expected Lead Time
138kV / 27 kV transformer banks	4	3 Years
27kV Switchgear	5 Sections	56 Weeks
27kV Secondary BUS	1800 ft.	48 Weeks
Circuit Switcher	4	80 Weeks
Circuit Interrupter	4	80 Weeks
Capacitor Banks	2	6 Months
L&P Transformers	2	9 Months
Precast Trench	1200 ft.	4 Months
138kV Solid Dialectric Cable	30 miles	6 Months
Manholes	108	3 Months

The new Area Substation is expected to be energized by May 2028. The estimated timeline to complete this project is below. This timeline is subject to change at any time, as the Company optimizes the project schedule and incorporates the final, detailed designs.

High-level Project Timeline - Gateway Park No. 1

Project Work Stream/ Scope:
Property Acquisition
Demolition
Foundation Construction
Building Construction (weather tight)
Building Interior Construction (mechanical, electrical, & plumbing)
Install Electrical Controls/ Indications Equipment
Install Transformers 1, 2, 3, & 4
Install Secondary BUS
Install Switchgear
Install Circuit Switchers
Install Circuit Interrupters
Install Capacitor Banks
Complete Transmission Route Study
Bid Transmission Design/Build Contract
Construction Transmission Feeders
Complete Terminations & Commissioning
Energize Station



In addition to purchasing property for the construction of the new Gateway Park No. 1 Area Substation, they have also completed transmission route studies, begun demolition at the property, begun detailed engineering design, and initiated procurement processes for long-lead-time equipment and design/build vendor contracts for transmission feeders.

Justification Summary:
The potential for the capacity of the Brownsville Area Substations and the associated feeders to be exceeded by load growth was first identified in 2014 and has been confirmed by subsequent updates to Company's Area Substation and Sub-transmission Feeder Ten-Year Load Relief Program (the LRP) - i.e., the study that identifies equipment on the transmission system that is at risk of failure due to overloads resulting from load growth on the system. The LRP is updated annually in the Spring using

the latest load forecast from the previous November. The 2024-2033 Load Relief Plan (2024 LRP) was finalized at the end of May 2024 and, like prior LRPs, it identified a risk that the capability of the Brownsville Area Substation transmission feeders could be exceeded during times of area peak loads.

Based on the current forecast, the Brownsville electric distribution networks (Crown Heights-3B, Ridgewood-5B, Richmond Hill-9B, and radial feeders 9B91-9B94) have projected loads that will cause the transmission feeders supplying the Brownsville load pocket (feeders: 38B01, 38B02, 38B03, 38B04 and 38B05) to exceed their capability as early as 2024. Interim solutions can address exceedances in the near-term, but a longer-term solution is needed beginning in 2028.

The 2024 LRP projects that forecasted load growth will cause the capability of the feeders to the Brownsville substations to be exceeded beginning in 2024 if the Company takes no action.

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Brownsville Nos. 1 & 2 Load - *No Action Taken* (adjusted for feeder peak diversity)	**804**	**822**	**843**	**859**	**870**	**883**	**917**	**939**	**964**	**993**
138 kV Feeder Capability	771	771	771	771	771	771	771	771	771	771
Exceedances if No Action Taken (i.e., amount that load exceeds capability)	**33**	**51**	**72**	**88**	**99**	**112**	**146**	**168**	**193**	**222**
Feeder Loading (%)	104%	107%	109%	111%	113%	115%	119%	122%	125%	129%

Given how much feeders are projected to become overloaded during this period, the Company must take steps in the near term to address the load issues in the first few years while pursuing other measures that provide more material load relief but will take longer to implement. Interim measures planned for implementation in 2024-2026 are a combination of traditional utility-side and customer-side solutions, combined with several easier to implement load transfers.

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Brownsville Nos. 1 & 2 Load - *No Action Taken* (adjusted for feeder peak diversity)	804	822	843	859	870	883	917	939	964	993
Interim Load Transfers:										
Crown Heights to Bensonhurst No. 2 (2024)	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
Crown Heights to Bensonhurst No. 2 (2025)	0	-5	-5	-5	-5	-5	-5	-5	-5	-5
Ridgewood to Glendale (2026)	0	0	-61	-62	-63	-64	-66	-68	-72	-74
	-1	-6	-67	-68	-69	-70	-72	-74	-78	-80
Brownsville Nos. 1 & 2 Load *Net of Interim* Load Transfers	803	816	776	791	801	813	845	865	886	913
Other Interim Measures										
Utility Sided Solutions	-11	-11	-11	-11	-10	-10	-10	-10	-11	-11
Customer Sided Solutions	-1	-1	-11	-11	-11	-11	-11	-11	-11	-11
	-12	-12	-22	-22	-21	-21	-21	-21	-22	-22
Brownsville Nos. 1 & 2 Load *Net of All Interim* Measures	791	804	754	769	780	792	824	844	864	891

In addition, the Company will operate the Brownsville feeders at 143 kV in 2024 and 2025 to boost capability.

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
138 kV Feeder Capability	771	771	771	771	771	771	771	771	771	771
Feeder Capability @ 143kV and 0.97 CF	807	807								
Feeder Capability	**807**	**807**	**771**	**771**	**771**	**771**	**771**	**771**	**771**	**771**

All together, these interim measures provide approximately 49 to 92 MWs of load relief on the Brownsville feeders over the 10-year forecast period. These measures do not, however, provide adequate load relief after the initial years, making it obvious that the Company can no longer defer construction of a new substation in the area. Construction of the Gateway Park No. 1 Area Station and the split of the Crown Heights network and transfer 120 MW from Brownsville No. 1 to Gateway – the permanent, long-term solution under this program – fully alleviates forecasted constraints on the Brownsville feeders.

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Exceedances *with* Interim Measures and Alternative Feeder operations but *without* Load Transfer to Gateway Park No. 1	-16	-3	-17	-2	9	21	53	73	93	120
Load Transfer from Crown Heights to Gateway Park No. 1	0	0	0	0	-123	-123	-126	-128	-131	-133
Exceedances *with* Load Transfer to Gateway Park No. 1	-16	-3	-17	-2	-114	-102	-73	-55	-38	-13

In addition, Gateway will also offer the benefit of allowing the Company to de-load the Bensonhurst load pocket if it becomes necessary.

The Gateway project will improve the reliability of networks by reducing the network sizes and will establish feasible resiliency options for various contingency events, which are not available with the existing distribution system design. The affected networks are: *(1)* Crown Heights (3B) network fed from Brownsville No. 1, *(2)* Ridgewood (5B) network fed from Brownsville No. 1, *(3)* Flatbush (4B) network fed from Bensonhurst 2 (BH2), and *(4)* Richmond Hill (9B) network fed from Brownsville No. 2.

Relationship to Broader Company Plans, Initiatives and the NYS Climate Leadership and Community Protection Act

The operational measures and system improvements implemented with this project would be sufficient in addressing load growth across Company networks in central Brooklyn.

By enabling load splits and smaller networks in the Brownsville and Bensonhurst load areas, this program will progressively increase the reliability of the associated networks in both the near and long term. It will help the Company avoid public safety issues related to network failure, customer outages and significant damage to Company equipment. Also, it will protect customers from any issues related to network shutdown.

Resiliency plans: this program will help during problems in the transmission and/or substation which limits the load capacity in the Bensonhurst and Brownsville substations. Once this project is complete, it will be more feasible to transfer out or partially restore the load coming out of Bensonhurst and Brownsville and help minimize the outage impact to customers.

This project is a core investment that enables the Company to continue to provide safe and reliable service, even as the nature of the grid changes. This aligns with Con Edison's strategic objective of providing world-class safety, reliability, and security, while managing the equity challenges of the energy transition.

This project supports the State's achievement of CLCPA and clean energy goals. This aligns with Con Edison's strategic objective to meet economy-wide net-zero GHG emissions in our service territories by 2050.

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection

An alternative considered was to rely upon Customer Sided Solutions (CSS) such as energy efficiency programs to mitigate any future transmission capacity deficiencies. Energy efficiency programs can provide cost-beneficial solutions across multiple customer segments by accelerating load relief through energy efficient upgrades and may aid in the deferral of traditional solutions for multiple years. Based on the magnitude of load relief required to address the overload constraints in Brooklyn under a limited time frame, it has been assessed that an energy efficiency program is not a viable option. There is no known contingency plan other than to pursue the identified traditional solution should this alternative be pursued and prove unable to meet the projected deficits.

Alternative 2 description and reason for rejection

Also considered was a plan for a different, traditional solution to the transmission capacity deficiencies associated with Bensonhurst Substations# 1 and # 2 and Brownsville Substations # 1 and # 2. Installing cable cooling plants for the feeders that supply Bensonhurst would increase their capacities and address the deficiencies. This alternative would likely require land procurement for the cooling plants themselves and would only solve the feeder rating deficiency and would not provide any network reliability improvements to the subject networks. Should load growth continue to a point where equipment within either of the Bensonhurst and/or Brownsville substations reach its maximum capacity, additional work would be required.

Alternative 3 description and reason for rejection
Transferring the entire 3B network into Gateway would also alleviate the Transmission level overloads but would only benefit a specific station and use up the capability of Gateway. Transferring the entire network would not improve network reliability. By partially transferring the 3B's, it creates the opportunity to split other networks in the future and also to introduce resiliency plans by establishing transferable load pockets between the new station and existing stations.

Risk of No Action
Risk 1
An overload on the transmission feeders supplying Brownsville #1 and #2 Substations is predicted to occur. Many of the Company's Brooklyn Queens substations are near full capacity and do not offer the feasibility of load transfer. In the event the transmission feeders become overloaded, load shedding may be required during peak conditions with service dropped to thousands of customers.

Risk 2
If this project is not pursued, the NRI of the Ridgewood network will be negatively impacted as continued growth without the ability to either split the network or increase feeders would result in an increasing NRI.

Non-Financial Benefits
Alleviating projected load constraints on the Brownsville feeders will improve reliability and resiliency in an area of New York City that serves many critical loads in a densely populated area where many buildings have elevators. As such, addressing these load constraints will allow the station to maintain the area substation N-1 reliability design criteria for long term projected load growth in Brooklyn.

Splitting the load in Crown heights and establishing a new network improves the reliability of the 3B network. This translates to lower customer outages and potentially avoids the high costs of significant network or substation events. New feeder cubicles vacated in Brownsville 1 can then be used to establish new feeders in Ridgewood decreasing the load per feeder. In addition, it will be possible to transfer load out of the southern portion of the Ridgewood network into the new 3B north network. This will have an additional positive reliability impact on the Ridgewood network.

The increased capacity brought on by Gateway offers the potential to minimize impact on customers during an area station event that limits station capacity. Resiliency options are not feasible in this load pocket without the use of rolling blackouts and mobile stations which take weeks to set up. By introducing new area station capacity and splitting current networks into smaller load areas, we will be able to handle loss of station capacity during emergencies while minimizing customer impact. If capacity at Brownsville, Bensonhurst or Gateway stations is compromised, load can be swapped between stations minimizing or eliminating the need for load shedding during an event. The design for network splits will account for resiliency by making accommodations for load swaps during emergencies.

Meeting New York's Climate Leadership Community Protection Act (CLCPA) goals will ultimately require the Company to build system capacity for an anticipated increase in load growth. With electrification of the City, as the transition from a carbon economy progresses, the system will need the capacity in the affected networks to accommodate unprecedented load growth. Rapid load growth has the potential to leave the Company in a difficult position to address all the relief and reliability challenges in the future.

Additionally, the completion of the scope of work needed to address load constraints at Brownsville facilitates the completion of other projects benefiting customers, including:

Splitting Flatbush (4B) network: The Bensonhurst load pocket will need load relief in the future. Fifteen new feeders will be extended west from Gateway to pick up the south portion of the 4B network. The south portion consists of mostly non-network 4kV load with a total of 127 MWs and 15 feeders. Six feeder cubicles would be released by this project in Bensonhurst 2 and can be used for new feeders in the 4B network and/or Brighton Beach (11B) networks. This would de-load the Bensonhurst load pocket and improve the reliability of the networks fed by it. In addition, the new load pocket can be made transferrable between Gateway and Bensonhurst No. 2 to add an element of resiliency to the project.

Ridgewood (5B) network: This network has the highest Network Reliability Index (NRI). With the construction of Gateway and the release of 3B South from BRO, three feeder cubicles will be made available in Brownsville No. 1, allowing for new feeders to be introduced into the 5B network. Also, a portion of 5B south of Broadway can be permanently transferred to 3B North thereby further improving the NRI of Ridgewood. Resiliency can also improve if this load pocket out of Ridgewood is made transferable between Gateway and Brownsville No. 1.

Richmond Hill (9B) network: This network can be split into two portions: 9B North and 9B South. This will greatly improve reliability by breaking the load into two smaller load pockets. The feeders from 3B South will be extended to and permanently pick up 9B South. This will reduce the load in the Brownsville load pocket and release four feeder cubicles in Brownsville No. 2 that can be used for new feeders in the 9B Network. 9B South can be made transferable between Gateway and Brownsville No. 2 to add an element of resiliency to the project.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)
N/A

2. Major financial benefits
This project will enable the Company to address potential transmission equipment overloads. Exceeding the capacity of the substation and transmission feeders could result in load shedding if contingencies occur during peak loading conditions, result in customer outages, and increase the risk of equipment failure and adverse impacts to the community served. The regulatory financial costs of load shedding customers and the cost of replacing transmission/station equipment can be significant to the Company. This project will mitigate the risk of incurring those costs.

3. Basis for estimate
The initial estimate of project cost (as discussed in the 2023-2025 rate case) was based on an order of magnitude estimate of project costs based on a conceptual design and historical costs for similar scopes of work. High-level estimates of total costs, by primary spend category, are shown below, including escalation, overheads, and contingency.

	Estimated Direct Costs	Esc., OH, & Other Loading[1]	Estimated Total	% of Total
01-Labor	$ 42,433,404	$ 83,023,300	$ 125,456,704	11.6%
02-MSH	$107,413,650	$117,741,500	$225,155,150	20.8%
03-Cont Svcs	$304,388,294	$333,654,600	$638,042,894	59.1%
09-Other	$ 43,773,200	$ 47,982,200	$ 91,755,400	8.5%
Total	**$498,008,548**	**$582,401,600**	**$1,080,410,148**	

[1]Includes: Escalation (18%), CE OH (14.07%), A&S (2.59%), PT&P (50.4%), AFDC (10.02%), and Contingency (30%)

Since this initial estimate was prepared – based on conceptual design – the Company has procured property, completed Transmission route studies, and begun detailed design, and, with the knowledge gained from these activities, refined cost estimates for portions of the project scope have been developed reflecting significant changes like the identification of a specific location for the substation and specific transmission routes.

While these revised estimates do project that the cost of *some* individual line items *may* be higher than what was projected in the initial estimate – for example, the initial cost estimate for the 93.3 MVA 138kV Transformers was $3.3M each but the latest estimates project these transformers to cost as much as $6.4M each – the contingency percentage (30%) included in the initial estimates will cover much of the cost difference, and other line items are likely to cost less than initially projected.

A full understanding of what the total project cost is likely to be – i.e., reflecting the exact station location, transmission routes, specific engineering designs, and current equipment and contractor pricing – will not be known until engineering design is completed for the major scopes of work and refined estimates are developed for each of the remaining scopes of work. (Updated cost estimates for the remaining scopes of work are expected to be completed in the second quarter of 2025.) Even then, the cost will be estimated with additional variances in actual costs possible as equipment is purchased and contracts put in place.

Project Risks and Mitigation Plan

Risk 1:

The vicinity of the above ground trains can make it difficult to find crossings/lanes for feeders.

Mitigation Plan 1:

Ensure via surveys that enough lanes are available for the feeder band runs. Obtain all permits ahead of time. Explore other options to go under any obstacles like trains.

Technical Evaluation / Analysis

Due to overload constraints identified for year 2028 on the 138kV sub-transmission system, a new area substation would be the only viable alternative for load relief. Con Edison is proposing a new 27kV indoor area substation, with five 138kV/27kV transformers and with a proposed in-service date of summer 2028. The split of the 3B network is complementary to the transmission/substation project and aims to transfer approximately 117 MW from the Brownsville 138KV transmission feeders to the Gateway Park area station.

In general, infrastructure adequacy is determined by comparing the infrastructure capability, in this case the transmission system supplying the Brownsville load pocket, against the net load to be served. The net load is determined from the gross forecasted customer demand less any load relief measures such as existing and forecasted energy efficiency or local distributed resources in the network.

The capability of the transmission system and the forecasted demand for the Brownsville load pocket includes consideration of customer sided and utility sided solution of 26 MWs. Capability of the 138 kV transmission system is based on using nominal operating voltage of 138 kV and Summer Normal feeder rating. Based on the demand forecast by 2028 and 138 kV feeder capabilities, the 138 kV transmission feeders were deficient, with deficiencies continuing to grow and will require load relief. Some temporary operating measures including the use of increased short term feeder ratings and/or higher operating voltages will be utilized until permanent relief is obtained.

Project Relationships (if applicable)
This project is sequential and complimentary to the establishment of the Gateway Park Area Station by 2028, a new indoor 27kV area substation that will be arranged in a double SYN bus configuration and with five 138/27kV transformer banks. The station will be supplied from the 345kV Brooklyn Clean Energy Hub.

3. Funding Detail ($000)

Historic Spend

	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Test Year (O&M Only)*	Forecast 2024
O&M	$0	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	N/A	$0
Capital	$0	$0	$0	$31,101	N/A	$30,000

2025-2029 Request:
Total Request by Year:

	2025	2026 (RY1)	2027 (RY2)	2028 (RY3)	2029
O&M	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	$0
Capital (Total)	$92,000	$478,190	$353,091	$365,909	$0
Labor	$20,237	$113,461	$76,208	$89,493	$0
M&S	$22,000	$115,757	$76,668	$85,571	$0
Contract Svcs.	$27,600	$133,213	$92,001	$99,833	$0
Other	$3,680	$18,374	$12,267	$14,262	$0
Overheads	$18,483	$97,385	$95,947	$76,751	$0

*The test year runs from 10/1/23 to 9/30/24.

Central Operations / Substation Operations
2025-2029

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Parkview TR5 & Feeder 38M85 (Mott Haven 345kV to Parkview)	
Project/Program Manager: Partha Roy	**Project/Program Number (Level 1):** 25493385
Status: ☒ **Initiation/Planning** ☐ **In-Progress (Projects Only)** ☐ **On-going (Programs Only)**	
Estimated Start Date: 2026	**Estimated Date In Service:** 2029
2025-2029 Funding Request ($000) **Capital:** $236,005 **O&M:** $0	

Work Description:
This project is designed to increase the capability of the Parkview Substation by 85 MW in 2029 by establishing a 138kV supply feeder 38M85 from the Mott Haven 345kV Substation to the Parkview 13kV Substation and installing a fifth 138/13kV transformer at Parkview. A fifth 345/138kV autotransformer at Mott Haven will also be required to provide the supply to Parkview.

The major scopes of work to be completed as part of this project include:

- Connect and install 345kV/138kV Autotransformer #10 (5th Bank) at Mott Haven 345kV Substation, with associated ground, disconnect switches and fire protection.
- At Mott Haven 345kV, install (2) 345kV GIS circuit breakers, 8 and 10, as well as associated 345kV disconnect/ground switches for both breakers.
- At Mott Haven 345kV, install 138kV GIS circuit breaker 10M4 along with associated disconnect/ground switches.
- Install 138kV GIS to open air potheads and connect 138kV feeder 38M85 to Parkview in addition to associated equipment.
- Install new 138kV feeder 38M85 from Mott Haven 345kV Substation to Parkview 13kV Substation.
- Establish new relay scheme for future feeder 38X30 and install all required relays and equipment. Modify existing relaying equipment and connections, as needed.
- At Parkview, install new 138kV potheads for new feeder 38M85.
- Install and connect 138kV/13kV Transformer #5 at Parkview Substation, along with associated circuit switcher / interrupter, ground switches and fire protection.

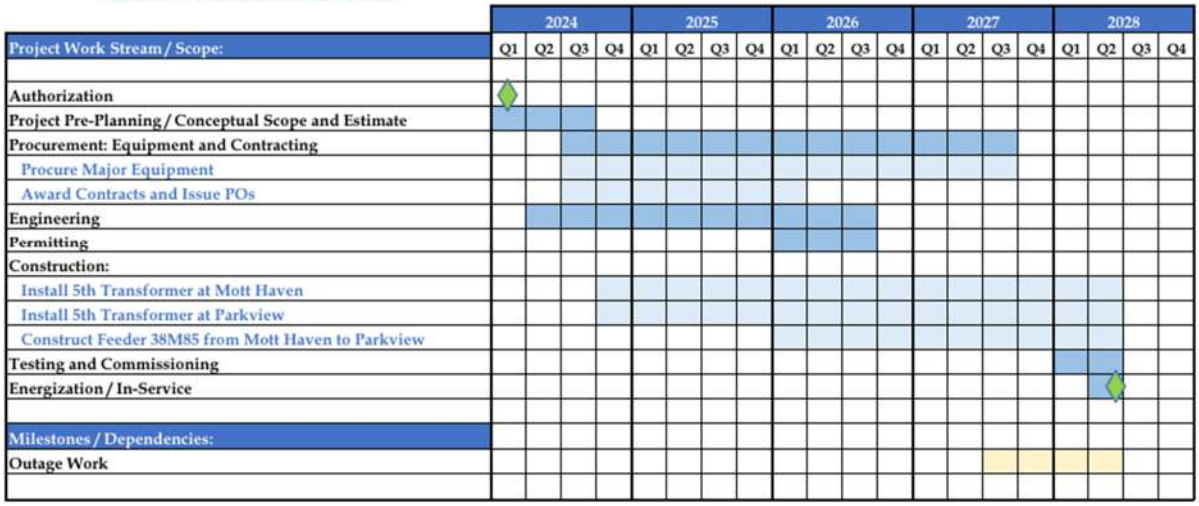
Major or long lead equipment requirements for the project include, but are not limited to:

Major Equipment Type	Number to be Purchased
138/13kV Transformer	1 each
138kV Circuit Switcher & Interrupter	1 each
138kV 3-1Ø Ground Switch	1 set
138kV 3Ø Ground Switch	1 each

345kV GIS Circuit Breaker	1 each
345kV GIS M.O. Disconnect Switch w/ 3Ø Ground Switch	3 each
345kV GIS 3Ø Ground Switch	1 each
345kV GIS 3-1Ø Potential Transformers w/ Disconnect Switch	1 set
345kV/138kV Autotransformer	1 each
138kV GIS M.O. Disconnect Switch w/ 3Ø Ground Switch	2 each
138kV GIS 3-1Ø Ground Switch	1 set
138kV GIS M.O. 3Ø Ground Switch	1 each
138kV GIS Circuit Breaker	1 each
138kV GIS Pothead Set	1 each

Engineering and long lead equipment procurement will begin in 2024 for this project and construction is expected to begin in 2025. The in-service date of this project is 2029. The estimated timeline to complete the major scopes of work associated with the project is below. This timeline is subject to change at any time, as the Company optimizes the project schedule and incorporates impacts of other projects and system performance.

Parkview TR5 and Feeder 39M85



Justification Summary:
Forecasted loads for the Parkview 13kV Substation are expected to exceed the station's design capability by the summer of 2030. New Load projections in the 2024 – 2033 Ten Year Load Relief Program indicate that the station's capability will be exceeded by 15 MW (109%) with overloads increasing as the load continues to grow in ensuing years. The rapid load growth in the network over the next few years is primarily driven by the expansion of the MTA's 2nd Avenue Subway line with associated economic activity in the area expected to continue.

Parkview	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Triboro	146	158	175	174	164	166	187	189	190	191
Electrification Adjustment	1	2	3	4	5	6	7	9	11	13
Other Adjustments	-3	-4	-5	-6	-7	-8	-5	-6	-6	-7
Net Load	144	156	173	172	162	164	189	192	195	197
Current Capability	**174**	174	174	174	174	174	174	174	174	174
Net Load as % of Current Capability	83%	90%	99%	99%	93%	94%	109%	110%	112%	113%
Capability with Expansion						**259**	259	259	259	259
New Load as % of Adjusted Capability						63%	73%	74%	75%	76%
Increase in Capability	85									

This project adds 85MW of capability to Parkview Substation and mitigates the risk of exceeding station capability resulting from expected increased customer heating electrification and the Company's clean energy commitment to meet NYS CLCPA goals. The Non-Wires Solutions (NWS) group has been engaged to provide support from 2027, but load growth will exceed their capabilities by 2029.

Relationship to Broader Company Plans, Initiatives and the NYS Climate Leadership and Community Protection Act

The operational measures and system improvements implemented with this project would be sufficient in managing overload constraints within the system.

This project is a core investment that enables the Company to continue to provide safe and reliable service, even as the nature of the grid changes. This aligns with Con Edison's strategic objective of providing world-class safety, reliability, and security, while managing the equity challenges of the energy transition.

2. Supplemental Information

Alternatives

The alternative solution considered is a 30MW load transfer from Parkview to West 110th Street No. 1. Although this load transfer is feasible and allows for load relief through 2040 based on the current forecast, there are various factors including significant costs and time constraints to rely on this option. Furthermore, should the load forecast increase for Parkview and/or West 110th Street Stations No. 1 & 2, the fifth transformer and 138kV feeder will still be operationally required at Parkview. The transferring of more load to networks which are themselves experiencing inherent growth tends to compromise that network's reliability and is a less desirable option.

In addition, all system expansion projects will be reviewed for non-wires solutions (NWS) in accordance with the suitability criteria outlined in the Distributed System Implementation Plan (DSIP). However, future demand forecasts are subject to change based on actual peak summer load conditions as well as economic trends and are likely to present significant challenges in achieving required customer side load reductions to provide adequate solutions in the face of rapid network load growth. Changes in future forecasts and planning may result in the advancement of addressing system overloads.

Risk of No Action

If no action is taken to alleviate forecasted capability exceedances at the Parkview substation, there is a high risk of overloading the substation equipment during peak load conditions. Exceeding the rated capacity of the substation could result in load shedding if contingencies occur during peak loading conditions resulting in customer outages, increasing the risk of equipment failure, and adversely impacting the community served, as well as encountering the potential inability of maintaining reliable system power flow controls, system reliability and resiliency concerns.

Non-Financial Benefits
Alleviating projected load constraints on the Parkview Substation increases reliability and resiliency in an area of New York City that serves critical loads in a densely populated area where many buildings have elevators and will allow the station to maintain the area substation N-1 reliability design criteria for long term projected load growth in Manhattan.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis (if required)
N/A

2. Major financial benefits
This project will enable the Company to address potential transmission equipment overloads. Exceeding the capacity of the substation and transmission feeders could result in load shedding if contingencies occur during peak loading conditions, result in customer outages, and increase the risk of equipment failure and adverse impacts to the community served. The regulatory financial costs of load shedding customers and the cost of replacing transmission/station equipment can be significant to the Company. This project will mitigate the risk of incurring those costs.

3. Basis for estimate
This estimate is based on an order of magnitude estimate of project costs based on a conceptual design and historical costs for similar scopes of work. High-level estimates of total costs, by primary spend category, are shown below, including escalation, overheads, and contingency.

	Estimated Direct Costs	*Esc., OH, & Other Loading*[1]	*Estimated Total*	*% of Total*
01-Labor	$ 10,896,976	$ 21,877,854	$ 32,774,830	13.9%
02-MSH	$ 48,407,813	$ 61,532,132	$109,939,945	46.5%
03-Cont Svcs	$ 34,248,088	$ 43,533,426	$ 77,781,514	32.9%
09-Other	$ 7,000,000	$ 8,897,839	$ 15,897,839	6.7%
Total	**$100,552,876**	**$135,841,252**	**$236,394,128**	

[1]Includes: Escalation (29%), CE OH (13.25%), A&S (2.53%), PT&P (39.35%), AFDC (11.62%), and Contingency (30%)

Project Risks and Mitigation Plan
Risk 1:
Delays due to resource/support coordination. There are a large number of projects to expand the electric distribution system that may strain existing resources.

Mitigation Plan 1:
Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts. Expand hiring and increase the number of employees over the next few years to be able to handle the increased flow of work.

Risk 2:
Material Availability Issues

Mitigation Plan 2:

Engineering will work with Supply Chain to establish a cohesive plan that aligns with vendor lead times. Stay engaged with vendors to ensure lead times are maintained, and adjust the plan as needed if shortages are encountered.
Technical Evaluation / Analysis Forecasted loads for Parkview in 2030 are approximately 189MW, which exceed the station's 174MW capability by 15MW or 9%. The overloads will increase in subsequent years as network load continues to grow. The growth in the Triboro Network load supplied by Parkview Substation is mostly due to expansion of the MTA's 2nd Avenue Subway line. To accommodate the forecasted load under a design N-2 contingency, a new 138/13kV transformer and new 138kV supply feeder are required at the Parkview Substation, along with a new 345/138kV transformer at the Mott Haven 345 transmission station.
Project Relationships (if applicable) N/A

3. Funding Detail ($000)

Historic Spend

	Actual 2020	**Actual 2021**	**Actual 2022**	**Actual 2023**	**Test Year* (O&M Only)**	**Forecast 2024**
O&M	$0	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	N/A	$0
Capital	$0	$0	$0	$0	N/A	$3,000

2025-2029 Request:

Total Request by Year:

	2025	**2026 (RY1)**	**2027 (RY2)**	**2028 (RY3)**	**2029**
O&M	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	$0
Capital (Total)	$18,005	$70,000	$120,000	$28,000	$0
Labor	$2,550	$9,951	$23,237	$4,011	$0
M&S	$3,465	$32,450	$48,760	$4,316	$0
Contract Svcs.	$6,441	$13,105	$17,990	$3,970	$0
Other	$2,945	$2,063	$3,500	$841	$0
Overheads	$2,603	$12,431	$26,513	$14,862	$0

*The test year runs from 10/1/2023 to 9/30/2024

Central Operations / Substation Operations

2025-2029

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Mott Haven 13kV – Install 5th Transformer & 138kV Supply Feeder 38X30	
Project/Program Manager: Partha Roy	**Project/Program Number (Level 1):** 27733931
Status: ☒ **Initiation/Planning** ☐ **In-Progress (Projects Only)** ☐ **On-going (Programs Only)**	
Estimated Start Date: 2026	**Estimated Date In Service:** 2029
2025-2029 Funding Request ($000) **Capital:** $47,340 **O&M:** $0	

Work Description:
This project is designed to increase the capability at the Mott Haven 13kV substation by 83 MW in 2029 to mitigate risks associated with future load growth forecasted for the Central Bronx load area. This project will establish a fifth 138/13kV transformer bank at Mott Haven, to be supplied by 138kV feeder 38X30.

Major scopes of work to be implemented under this project include:

- Mott Haven 13kV
  - Connect and install new 138kV/13kV transformer #5 and 138kV potheads.
  - Connect and install all associated fire protection, 138kV overhead bus, and 13kV overhead bus.
  - Install and connect new control cables and connect to existing relay panels. Modify relay protection, as necessary.
  - Install and establish new relay scheme for future feeder 38X30 and associated equipment.
- At Mott Haven 345kV
  - Install 138kV GIS circuit breaker 10X1 along with associated disconnect/ground switches.
  - Install 138kV GIS to open air potheads and connect 138kV feeder 38X30.
  - Install new 138kV feeder 38X30 (new cable to be installed in existing feeder conduit).
  - Provide structural supports for all elevated conduits, feeders, control cables and penetrations through floors or walls.

Major or long lead equipment requirements for the project include, but are not limited to:

Major Equipment Type	Number to be Purchased
138/13kV 65MVA Transformer	1 each
138kV GIS Circuit Breaker	1 each
345kV GIS M.O. Disconnect Switch w/ 3Ø Ground Switch	2 each
345kV GIS Circuit Breaker	1 each

Engineering and long lead equipment procurement will begin in 2026 for this project and construction is expected to begin in 2028 and to be completed in 2029. The estimated timeline to complete the major scopes of work associated with the project is below. This timeline is subject to change at any time, as the Company optimizes the project schedule and incorporates impacts of other projects and system performance.

Project Timeline / High-level Work Plan

	2026				2027				2028				2029			
Project Work Stream / Scope:	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Authorization	◆															
Pre-Planning / Conceptual Scope and Estimate	■															
Appropriations		■	■													
Procurement: Land, Equipment, and Contracting																
Procure Major Equipment				■	■	■	■	■	■	■	■					
Award Contracts						■	■	■	■							
Engineering		■	■	■	■											
Permitting				■	■	■	■	■								
Site Preparation (including demolition)							■	■	■							
Construction:																
Install Major Substation Equipment										■	■	■				
Install Auxiliary Equipment											■	■				
Construct new Feeder										■	■					
Testing and Commissioning													■			
Energization / In-Service														◆		

Justification Summary:
Previously, Con Edison utilized deterministic processes to assess load relief need. This process resulted in "just-in-time" project completion as the year the energy forecast's projected demand exceeds a substation's prior design capability. Forecast uncertainty due to the dynamic energy landscape driven by the Climate Leadership and Community Protection Act (CLCPA) and NY state policies has required the Company to adapt the existing planning process to capture elements of risk. For this reason, the Company has elected to incorporate a transmission probabilistic reliability assessment (TPRA) method of planning where risk of customer load drops is quantified to prioritize substation work in the riskiest stations to maintain system reliability. The TPRA model analyzes residual system risk in conjunction with supporting the deterministic planning method. The Company has developed, updated and utilized this model for the past 20 years to prioritize and optimize reliability projects by quantifying load drop risks under different load growth scenarios.

Mott Haven, specifically, is forecasted to have its station capability surpassed in 2034 based on the Company's forecast projections. With "just-in-time" planning, this project would be scheduled to be completed in 2034. However, probabilistic assessment identified this station to have an elevated risk of load drop as early as 2029 as it approaches the substation capacity. For this reason, the project timeline has been risk adjusted at Mott Haven from 2034 to 2029.

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Mott Haven										
Central Bronx	198	204	210	214	218	220	221	223	224	226
Electrification Adjustment	5	6	7	9	12	16	19	23	27	32
Other Adjustments	-4	-5	-6	-7	-7	-6	-5	-6	-6	-6
Net Load	199	205	211	216	223	230	235	240	245	252
Capability	249				333					

The rapid load growth in the Central Bronx network over the next several years is primarily driven by electrification and associated economic activity in the area, a trend expected to continue. This electrification includes the Hunts Point Cooperative Market (and anticipated load growth from supporting trucks, truck refrigeration units, and a freight EV charging facility associated with it), and thousands of personal and commercial vehicles in the area that must electrify to meet policy mandates, and several specific customer electrification plans. Thus, this project is required based on future expected electrification load and associated risk of load drop.

The capacity expansion of Mott Haven will support a variety of new loads. This project will not only aid in transportation electrification but all loads, including support building decarbonization and New York State goals and regulations by ensuring capacity exists for customers to connect to the grid.

Relationship to Broader Company Plans, Initiatives and the NYS Climate Leadership and Community Protection Act

This project will strengthen the reliability of the transmission system and networks served by the Mott Haven Substation including Disadvantaged Communities (DACs) downstream from this project.

This project was also included in the Company's Proactive Planning proceeding (Case # 24-E-0364) Urgent Projects Filing to support grid infrastructure needs for transportation and building electrification. If funding is granted in the Proactive Planning proceeding, capital investments under this rate case will be adjusted as appropriate.

2. Supplemental Information

Alternatives

Alternative 1

Load Transfer – Transfer 30 MW load from the Central Bronx load area into the adjacent Fordham network supplied from the East 179 Street area substation. This alternative was rejected, as the East 179 Street area substation is slated to provide load relief to the Bruckner area substation in 2039 via 60 MW load transfer. For the East 179 Street area substation to accept 60 MW load transfer from Bruckner in 2039, in 2038 a 70 MW load transfer from East 179 Street must be sent to the Riverdale network supplied by the Sherman Creek area substation, which will have its 138kV sub-transmission supply feeders at 100% capacity in 2043 (20-year planning window). The load transfer would not add capacity to the electric system. Furthermore, Bruckner, East 179 Street, and Sherman Creek area substations are expected to see additional transportation electrification loads. Therefore, this solution is not feasible as well as temporary and inefficient.

Risk of No Action

If no action is taken to alleviate forecasted capability exceedances at the Mott Haven 13kV substation, there is a high risk of overloading the substation equipment during peak load conditions. Exceeding the rated capacity of the substation could result in load shedding if contingencies occur during peak loading conditions, increasing the risk of equipment failure, and adversely impacting the community served, as well as encountering the potential inability of maintaining reliable system power flow controls, system reliability and resiliency concerns.

There is a real risk of delays in providing service to customers, impacting critical customer plans, and delaying achievement of intermediate climate policy goals related to transportation and building electrification as well as delaying improvements in the air quality in these communities.

Non-Financial Benefits

The primary electric system non-financial benefits for this project are maintaining the robust system reliability standard as loads increase, as well as contributing to New York State's clean energy goals. The area will undergo significant transportation and building electrification, and Hunts Point Cooperative market currently depends on diesel generation for their large-scale refrigeration; this project will strengthen the system to accommodate the large increase in load from electrification.

Based on Con Edison's internal analysis, by 2040 this project will support charging of light-, medium-, and heavy-duty vehicles and electrification of heating systems to avoid 256 thousand tons of carbon dioxide equivalent (CO2e) that year, with a total avoided emissions of 2,240 thousand CO2e from the in-service date through 2040, and even more in the years beyond.

The grid readiness resulting from this project will signal to customers looking to electrify in compliance with policy mandates that the grid is ready to accommodate their load requests without delaying their plans. This project will thus strengthen relationships with our customers and communities. By proactively building out our grid to be ready for new loads, we are increasing customer trust and a better customer experience to enable a smoother and expedited New Business process.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)
N/A

2. Major financial benefits
N/A

3. Basis for estimate
The estimate is based on an order of magnitude estimate of project costs based on a conceptual design and historical costs for similar scopes of work. High-level estimates of total costs, by primary spend category, are shown below, including escalation, overheads, and contingency.

	Estimated Direct Costs	*Esc., OH, & Other Loading*[1]	*Estimated Total*	*% of Total*
01-Labor	$ 4,950,536.00	$ 6,405,607.00	$ 11,356,143.00	24.0%
02-MSH	$ 9,288,553.00	$ 6,800,568.00	$ 16,089,120.00	34.0%
03-Cont Svcs	$ 9,744,005.00	$ 7,134,024.00	$ 16,878,029.00	35.7%
09-Other	$ 1,740,142.00	$ 1,274,036.00	$ 3,014,178.00	6.4%
Total	**$ 25,723,236.00**	**$ 21,614,235.00**	**$ 47,337,470.00**	

[1]Includes: Escalation (3.00%), CE OH (13.25%), A&S (2.53%), PT&P (39.35%), AFDC (6.62%), and Contingency (30%)

Project Risks and Mitigation Plan

Risk 1:
The vicinity of the above ground trains can make it difficult to find crossings/lanes for feeders.

Mitigation Plan 1:

Perform surveys to find enough lanes for the feeder band runs. Obtain all permits ahead of time. Explore other options to go under any obstacles like trains.

Risk 2:
Uncertainty of timing, location, and magnitude (i.e., appropriate sizing) of load materialization.

Mitigation Plan 2:
While there is some uncertainty around the exact timing of customer electrification and which customers will electrify at any given time, the general timeframe for load increases across the area is well known, given existing policies. The Company's Granular EV Load Projection analysis significantly constrains the locations and magnitude of EV adoption. This analysis links directly to State policy objectives, considers available funding and active electrification projects, and was corroborated by extensive outreach to fleet customers.

- Timing: as discussed in the Justification section above, policy objectives and specific customer plans dictate electrification timelines, which the Company used to mitigate the risk of being late. The risk of being too early is minimal due to the accelerating project plans already identified in the region and the high confidence in the load materializing. Furthermore, once transformers are installed, they will increase system reliability. All this work will signal to the customers in the Central Bronx – Hunts Point FDC buildings and fleets, municipal vehicles, utility fleets, and other commercial customers – that the grid is ready to accommodate their electrification without long lead times for utility construction.
- Locations: depot locations in this region are known and not expected to change over time given restricted land availability in the area and the established FDC.

The Hunts Point FDC specifically is one of the busiest FDCs in the country and will need to electrify to support NYS climate goals. Designing new infrastructure with this facility as an anchor load significantly reduces the uncertainty of timing and location of additional load.

Technical Evaluation / Analysis
N/A

Project Relationships (if applicable) This project is required to support the projected electrification loads within the Hunts Point hotspot and ensure the capacity exists and service reliability is maintained for this load, reference the Company's Proactive Planning proceeding (Case # 24-E-0364) Urgent Projects Filing for more details on the Hunts Point hotspot.

3. Funding Detail ($000)

Historic Spend

	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Test Year* (O&M Only)	Forecast 2024
O&M	$0	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	N/A	$0
Capital	$0	$0	$0	$0	N/A	$0

2025-2029 Request:
Total Request by Year:

	2025	2026 (RY1)	2027 (RY2)	2028 (RY3)	2029
O&M	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	$0
Capital (Total)	$0	$10,000	$10,000	$20,000	$7,340
Labor	$0	$1,400	$2,200	$4,400	$1,100
M&S	$0	$3,900	$1,230	$2,460	$615
Contract Svcs.	$0	$1,600	$3,763	$7,526	$1,882
Other	$0	$382	$0	$0	$0
Overheads	$0	$2,718	$2,807	$5,614	$1,403

*The test year runs from 10/1/2023 to 9/30/2024

Central Operations / Substation Operations

2025-2029

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Brownsville Area Load Relief – Glendale TR5 and Feeder 38Q05 Extension	
Project/Program Manager: Charles Davoren	**Project/Program Number (Level 1):** 26402979
Status: ☒ **Initiation/Planning** ☐ **In-Progress (Projects Only)** ☐ **On-going (Programs Only)**	
Estimated Start Date: 2026	**Estimated Date In Service:** 2030
2025-2029 Funding Request ($000) **Capital:** $113,050 **O&M:** $0	

Work Description:
This project is part of a Company program designed to alleviate forecasted overloads on the 138kV feeders supplying the Brownsville Area Substations. The Company first identified the need for a new substation to provide relief for the Brownsville substation in 2014, but prior load forecasts showed the Brooklyn Queens Demand Management Program (BQDM) deferring the need for the new station until 2032. More recent forecasts, however, show significant, near-term load growth in the area (including adoption of electric vehicles and electric heating) indicate that a new station is needed by 2028.

Because of the risk that subsequent load growth in the area could create reliability issues before the long-term solution can be implemented, the planned Company program includes both interim solutions and a long-term solution, planned for implementation beginning in 2024 and with the final, long-term solution implemented in 2028.

Interim solutions identified to address Brownsville feeder overloads include:

- 2024-2025: Operate the Farragut to Brownsville 138 kV feeders at 143 kV and 0.97 Power Factor
- 2024-2033: Install/maintain alternate utility and customer sided solutions for BQDM
- 2024: Transfer Metropolitan Transportation Authority (MTA) transit rectifier station (HTV70S1) from Crown Heights (3B) to Flatbush (4B), reducing Brownsville feeder load by approximately 2 MW. (completed)
- 2025: Transfer MTA transit rectifier station (HTV2337) and Starr 4kV Autoloop from Ridgewood (SB) to Maspeth (6Q), reducing feeder load by approximately 4 MW.
- 2026: Install a fourth transformer at Newtown and a new 138kV sub-transmission feeder (38Q05) from the Vernon substation to the Newtown Substation (making capacity available on the 138 kV Vernon sub-transmission feeders supplying Glendale, Newtown & Amtrak) and transfer 60 MW from Brownsville No. 1 to Glendale.

The long-term solution to providing Brownsville load relief under this program is to construct the new Gateway Park Area Substation, to be supplied by the new Brooklyn Clean Energy Hub via four new 138kV sub-transmission feeders. The capital projects involved in completing the Gateway Park Area Substation and alleviating forecasted Brownsville overloads include:

- 2028: Establish Gateway Park Area Substation No. 1
- 2028: Split Crown Heights network and transfer 120 MW from Brownsville No. 1 to Gateway Park No. 1

This project is necessary following implementation of one of the interim measures, specifically the transfer of 60 MW from Brownsville No. 1 to Glendale in 2026 which results in a future constraint at Glendale.

This project will install a fifth 138kV/27kV transformer at Glendale and extend the 38Q05 138kV sub-transmission feeder approximately 2.7 miles from Newtown to Glendale.

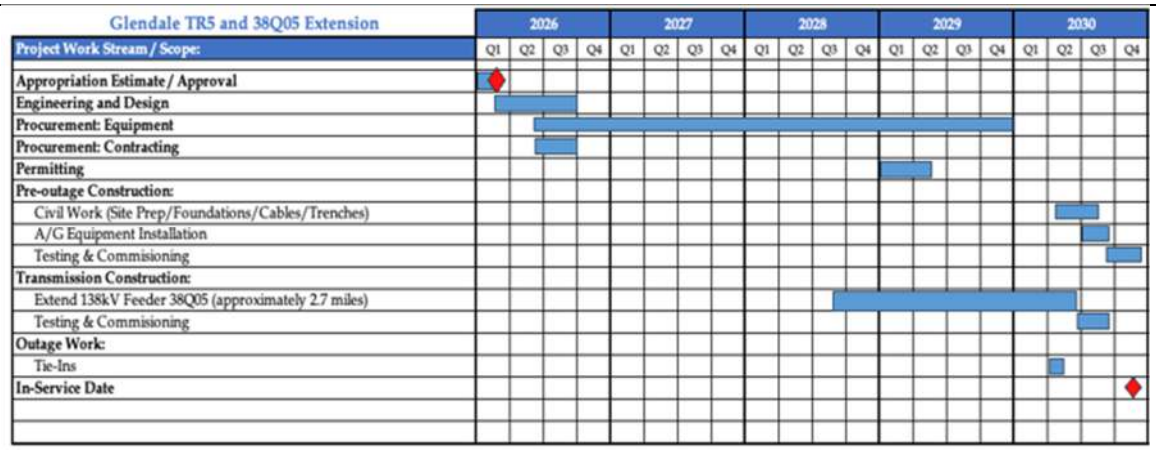
The major scopes of work to be completed to install the fourth transformer at Newtown and feeder 38Q05 include:

- Install one 138/27kV transformer foundation.
- Install one 138kV circuit switcher support structure & associated foundation.
- Install one 138kV pothead support structure & associated foundation.
- Install new transformer vault walls, including foundations.
- Install new vehicle gate and roadway.
- Install two new 27kV switchgear section foundations.
- Extend 138kV feeder 38Q05 approximately 2.7 miles, from Newtown to Glendale
- Install and connect new 138/27kV Transformer 5 and 27kV bus sections 5E and 5W, including:
    - Potheads
    - Circuit switcher/interrupter
    - 27kV breakers 51E, 51W, 52E, 52W, 53E, 53W, 54E, 54W, 5SYE, 5SYW, 5TE, 5TR, & 5TW

Engineering and long lead equipment procurement will begin in 2026 for this project and station construction is expected to begin in early 2028. Major or long lead equipment requirements for the project include, but are not limited to:

Major Equipment Type	Number to be Purchased
138kV Pothead Stand	1
138/27kV Transformer	1
27kV 3Ø Segregated Bus	400 feet
27kV Transformer Circuit Breaker	13
138kV Circuit Switcher & Interrupter	1
138kV 3-1Ø Ground Switch	1
138kV 3Ø Ground Switch	1

Work on this project is to begin in 2026 and is to be completed in 2030. The estimated timeline to complete the major scopes of work associated with the project is below. This timeline is subject to change at any time, as the Company optimizes the project schedule and incorporates impacts of other projects and system performance.



Justification Summary:

This project is needed to alleviate future load constraints on theVernon 138 kV sub-transmission feeders (which supply Newtown, Glendale and Amtrak Stations) following implementation of interim load relief measures at the Brownsville Area Substation, specifically, the transfer of 60 MW from Brownsville No. 1 to Glendale in 2026. (See discussion below for justification of this 60 MW load transfer.) The addition of the 60 MW at Glendale in 2026 results in the Vernon 138 kV supply sub-transmission feeder exceeding it's capability in 2031. This project mitigates potential risk from continued load growth (including growth on the transferred 60 MW) by increasing Glendale Area Substation capability and increasing the Vernon 138kV supply sub-transmission feeder capability by 2030.

Previously, Con Edison utilized purely deterministic processes to assess load relief need. This process resulted in "just-in-time" project completion as the year the energy forecast's projected demand approaches a substation's capability. Forecast uncertainty due to the dynamic energy landscape driven by the Climate Leadership and Community Protection Act (CLCPA) and NY state policies have required the Company to adapt the existing planning process to capture other elements of risk. For this reason, the Company has elected to incorporate a probabilistic method of planning where risk of customer interruption is modeled to prioritize substation work in the riskiest stations and maintain system reliability.

Based on forecasted load growth for Glendale Area Substation with the addition of the 60 MW load transfer from Brownsville No.1, the Glendale Area Substation Vernon 138 kV supply sub-transmission feeders would have its capability surpassed in 2031. With "just-in-time" planning, this project would be scheduled on this analysis. However, probabilistic assessment identified this station to have an elevated risk of customer interruption as it approaches capacity on its Vernon 138 kV supply sub-transmission feeders. For this reason, the project timeline has been risk adjusted at Glendale from 2031 to 2030.

Based on forecasts of load growth at Glendale included in the 2024 Load Relief Program (LRP), Glendale station Vernon 138 kV supply sub-transmission feeder capability will be exceeded in 2031 as seen below:

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Glendale										
Maspeth	243	247	310	312	313	315	316	317	319	320
Radial	30	30	31	31	32	32	32	33	33	34
Total Load	273	277	341	343	345	347	348	350	352	354
Electrification Adjustment	2	10	13	16	20	27	35	49	63	80
Other Adjustments	-2	-1	-3	-4	-5	-7	-2	-4	-4	-6
Non-Wires Solutions (NWS) (4)	-1	-6	-6	-6	-6	-6	-6	-6	-6	-6
Net Load	272	280	345	349	354	361	375	389	405	422
Capability	390						517			
Amtrak-Sunnyside	10	13	13	13	13	17	18	18	18	18
Newtown										
Borden	130	138	147	152	154	157	160	162	164	167
Sunnyside	72	74	76	78	78	79	80	80	81	81
Total Load	202	212	223	230	232	236	240	242	245	248
Electrification Adjustment	3	5	7	9	12	14	17	20	24	27
Other Adjustments	-3	-5	-5	-6	-9	-13	-10	-11	-14	-15
Non-Wires Solutions (NWS) (4)	0	-5	-5	-5	-5	-5	-5	-5	-5	-5
Net Load	202	207	220	228	230	232	242	246	250	255
Capability	244		361							
Glendale+Newtown+Amtrak	484	500	578	590	597	610	635	653	673	695
Feeder Peak Diversity (6)	-2	-10	-10	-13	-19	-24	-33	-40	-46	-55
Net Load	482	490	568	577	578	586	602	613	627	640
138 kV Feeder Capability (2)(3)(5)	569		606				763			
Vernon-Glendale 138kV Fdr.Loading	85%	86%	94%	95%	95%	97%	79%	80%	82%	84%

The potential for the capacity of the Brownsville Area Substations and the associated feeders to be exceeded by load growth was first identified in 2014 and has been confirmed by subsequent updates to Company's Area Substation and Sub-transmission Feeder Ten-Year Load Relief Program (the LRP) - i.e., the study that identifies equipment on the sub-transmission system that is at risk of failure due to overloads resulting from load growth on the system. The LRP is updated annually in the Spring using the latest load forecast from the previous November. The 2024-2033 Load Relief Program (2024 LRP) was finalized at the end of May 2024, and, like prior LRPs, it identified a risk that the capability of the Brownsville Area Substation transmission feeders could be exceeded during times of area peak loads.

Based on the current forecast, the Brownsville electric distribution networks (Crown Heights-3B, Ridgewood-5B, Richmond Hill-9B, and radial feeders 9B91-9B94) have projected loads that will cause the transmission feeders supplying the Brownsville load pocket (feeders: 38B01, 38B02, 38B03, 38B04 and 38B05) to exceed their capability as early as 2024. Interim solutions can address exceedances in the near-term, but a longer-term solution is needed beginning in 2028, when the 2023 LRP projected Brownsville No. 1 & 2 to be at 100% capacity in 2028.

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Brownsville No. 1 & 2	786	786	791	795	790	792	795	797	799	822
Utility Sided Solutions (1)	-19	-19	-19	-20	-19	-19	-19	-20	-20	-20
CSS (1), (2)	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6
Net Load	761	761	766	769	765	767	770	771	773	796

138 kV Feeder Capability 771
(S.N. Rating = 847 Amperes)

The 2024 LRP projects forecasted that load growth will cause the capability of the feeders to the Brownsville substations to be exceeded beginning in 2024 if the Company takes no action.

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Brownsville Nos. 1 & 2 Load - *No Action Taken* (adjusted for feeder peak diversity)	804	822	843	859	870	883	917	939	964	993
138 kV Feeder Capability	771	771	771	771	771	771	771	771	771	771
Exceedances if No Action Taken (i.e., amount that load exceeds capability)	33	51	72	88	99	112	146	168	193	222
Feeder Loading (%)	104%	107%	109%	111%	113%	115%	119%	122%	125%	129%

Given how much these feeders are projected to become overloaded during this period, the Company must take steps in the near term to address the load issues in the first few years while pursuing other measures that provide more material load relief but will take longer to implement. Interim measures planned for implementation in 2024-2026 are a combination of traditional utility-side and customer-side solutions, combined with several easier to implement load transfers.

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Brownsville Nos. 1 & 2 Load - *No Action Taken* (adjusted for feeder peak diversity)	804	822	843	859	870	883	917	939	964	993
Interim Load Transfers:										
Crown Heights to Bensonhurst No. 2 (2024)	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
Crown Heights to Bensonhurst No. 2 (2025)	0	-5	-5	-5	-5	-5	-5	-5	-5	-5
Ridgewood to Glendale (2026)	0	0	-61	-62	-63	-64	-66	-68	-72	-74
	-1	-6	-67	-68	-69	-70	-72	-74	-78	-80
Brownsville Nos. 1 & 2 Load *Net of Interim* Load Transfers	803	816	776	791	801	813	845	865	886	913
Other Interim Measures										
Utility Sided Solutions	-11	-11	-11	-11	-10	-10	-10	-10	-11	-11
Customer Sided Solutions	-1	-1	-11	-11	-11	-11	-11	-11	-11	-11
	-12	-12	-22	-22	-21	-21	-21	-21	-22	-22
Brownsville Nos. 1 & 2 Load *Net of All Interim* Measures	791	804	754	769	780	792	824	844	864	891

In addition, the Company will operate the Brownsville feeders at 143 kV in 2024 and 2025 to boost capability.

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
138 kV Feeder Capability	771	771	771	771	771	771	771	771	771	771
Feeder Capability @ 143kV and 0.97 CF	807	807								
Feeder Capability	807	807	771	771	771	771	771	771	771	771

All together, these interim measures provide approximately 49 to 92 MWs of load relief on the Brownsville feeders over the 10-year forecast period. These measures do not, however, provide adequate load relief after the initial years, making it obvious that the Company can no longer defer construction of a new substation in the area. Construction of the Gateway Park No. 1 Area Station and the split of the Crown Heights network and transfer 120 MW from Brownsville No. 1 to Gateway – the permanent, long-term solution under this program – fully alleviates forecasted constraints on the Brownsville feeders.

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Exceedances *with* Interim Measures and Alternative Feeder operations but *without* Load Transfer to Gateway Park No. 1	-16	-3	-17	-2	9	21	53	73	93	120
Load Transfer from Crown Heights to Gateway Park No. 1	0	0	0	0	-123	-123	-126	-128	-131	-133
Exceedances *with* Load Transfer to Gateway Park No. 1	-16	-3	-17	-2	-114	-102	-73	-55	-38	-13

In addition, Gateway will also offer the benefit of allowing the Company to de-load the Bensonhurst load pocket if it becomes necessary.

The Gateway project will improve the reliability of networks by reducing the network sizes and will establish feasible resiliency options for various contingency events, which are not available with the existing distribution system design. The affected networks are: *(1)* Crown Heights (3B) network fed from Brownsville No. 1, *(2)* Ridgewood (5B) network fed from Brownsville No. 1, *(3)* Flatbush (4B) network fed from Bensonhurst 2 (BH2), and *(4)* Richmond Hill (9B) fed from Brownsville No. 2.

Relationship to Broader Company Plans, Initiatives and the NYS Climate Leadership and Community Protection Act

The operational measures and system improvements implemented with this project would be sufficient in addressing load growth across Company networks in central Brooklyn.

By enabling load splits and smaller networks in the Brownsville and Bensonhurst load areas, this program will progressively increase the reliability of the associated networks in both the near and long term. It will help the Company avoid public safety issues related to network failure, customer outages and significant damage to Company equipment. Also, it will protect customers from any issues related to network shutdown.

Resiliency plans: this program will help during problems with the transmission feeders and/or substations which limit the load capacity in the Glendale, Bensonhurst, or Brownsville substations. Once this project is complete, it will be more feasible to transfer out or partially restore the load coming out of Bensonhurst and Brownsville and help minimize the outage impact to customers.

This project is a core investment that enables the Company to continue to provide safe and reliable service, even as the nature of the grid changes. This aligns with Con Edison's strategic objective of providing world-class safety, reliability, and security, while managing the equity challenges of the energy transition.

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection

An alternative considered was to rely upon Customer Sided Solutions (CSS) such as energy efficiency programs to mitigate any future transmission capacity deficiencies. Energy efficiency programs can provide cost-beneficial solutions across multiple customer segments by accelerating load relief through energy efficient upgrades and may aid in the deferral of traditional solutions for multiple years. Based on the magnitude of load relief required to address the overload constraints in Brooklyn under a limited time frame, it has been assessed that an energy efficiency program is not a viable option. There is no known contingency plan other than to pursue the identified traditional solution should this alternative be pursued and prove unable to meet the projected deficits.

Risk of No Action

Risk 1

An overload on the transmission feeders supplying Glendale is predicted to occur. Many of the Company's Brooklyn Queens substations are near full capacity and do not offer the feasibility of load transfer. In the event the transmission feeders become overloaded, load shedding may be required during peak conditions with service dropped to thousands of customers.

Risk 2
If this project is not pursued, the NRI of the Ridgewood network will be negatively impacted as continued growth without the ability to either split the network or increase feeders would result in an increasing NRI.

Non-Financial Benefits
Alleviating projected load constraints on the Glendale feeders will improve reliability and resiliency in an area of New York City that serves many critical loads in a densely populated area where many buildings have elevators and will allow the station to maintain the area substation N-1 reliability design criteria for long term projected load growth in Brooklyn.

Splitting the load in Crown heights and establishing a new network improves the reliability of the 3B network. This translates to lower customer outages and potentially avoids the high costs of significant network or substation events. New feeder cubicles vacated in Brownsville 1 can then be used to establish new feeders in Ridgewood decreasing the load per feeder. In addition, it will be possible to transfer load out of the southern portion of the Ridgewood network into the new 3B north network. This will have an additional positive reliability impact on the Ridgewood network.

The increased capacity brought on by Gateway offers the potential to minimize impact on customers during an area station event that limits station capacity. Resiliency options are not feasible in this load pocket without the use of rolling blackouts and mobile stations which take weeks to set up. By introducing new area station capacity and splitting current networks into smaller load areas, we will be able to handle loss of station capacity during emergencies while minimizing customer impact. If capacity at Brownsville, Bensonhurst or Gateway stations is compromised, load can be swapped between stations minimizing or eliminating the need for load shedding during an event. The design for network splits will account for resiliency by making accommodations for load swaps during emergencies.

Meeting New York's Climate Leadership Community Protection Act (CLCPA) goals will ultimately require the Company to build system capacity for an anticipated increase in load growth. With electrification of the City, as the transition from a carbon economy progresses, the system will need the capacity in the affected networks to accommodate unprecedented load growth. Rapid load growth has the potential to leave the Company in a difficult position to address all the relief and reliability challenges in the future.

Additionally, the completion of the scope of work needed to address load constraints at Brownsville facilitates the completion of other projects benefiting customers, including:

Splitting Flatbush (4B) network: The Bensonhurst load pocket will need load relief in the future. Fifteen new feeders will be extended west from Gateway to pick up the south portion of the 4B network. The south portion consists of mostly non-network 4kV load with a total of 127 MWs and 15 feeders. Six feeder cubicles would be released by this project in Bensonhurst 2 and can be used for new feeders in the 4B network and/or Brighton Beach (11B) networks. This would de-load the Bensonhurst load pocket and improve the reliability of the networks fed by it. In addition, the new load pocket can be made transferrable between Gateway and Bensonhurst No. 2 to add an element of resiliency to the project.

Ridgewood (5B) network: This network has the highest Network Reliability Index (NRI). With the construction of Gateway and the release of 3B South from BRO, three feeder cubicles will be made available in Brownsville No. 1, allowing for new feeders to be introduced into the 5B network. Also, a portion of 5B south of Broadway can be permanently transferred to 3B North thereby further improving

the NRI of Ridgewood. Resiliency can also improve if this load pocket out of Ridgewood is made transferable between Gateway and Brownsville No. 1.

Richmond Hill (9B) network: This network can be split into two portions: 9B North and 9B South. This will greatly improve reliability by breaking the load into two smaller load pockets. The feeders from 3B South will be extended to and permanently pick up 9B South. This will reduce the load in the Brownsville load pocket and release four feeder cubicles in Brownsville No. 2 that can be used for new feeders in the 9B Network. 9B South can be made transferable between Gateway and Brownsville No. 2 to add an element of resiliency to the project.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)
N/A

2. Major financial benefits
This project will enable the Company to address potential transmission equipment overloads. Exceeding the capacity of the substation and transmission feeders could result in load shedding if contingencies occur during peak loading conditions, result in customer outages, and increase the risk of equipment failure and adverse impacts to the community served. The regulatory financial costs of load shedding customers and the cost of replacing transmission/station equipment can be significant to the Company. This project will mitigate the risk of incurring those costs.

3. Basis for estimate
This estimate is based on an order of magnitude estimate of project costs based on a conceptual design and historical costs for similar scopes of work. High-level estimates of total costs, by primary spend category, are shown below, including escalation, overheads, and contingency.

	Estimated Direct Costs	*Esc., OH, & Other Loading*[1]	*Estimated Total*	*% of Total*
01-Labor	$ 8,335,334	$ 15,435,790	$ 23,771,124	17.9%
02-MSH	$ 19,244,750	$ 22,197,617	$ 41,442,367	31.2%
03-Cont Svcs	$ 26,430,217	$ 30,485,605	$ 56,915,822	42.8%
09-Other	$ 5,047,363	$ 5,821,819	$ 10,869,182	8.1%
Total	**$ 59,057,664**	**$ 73,940,831**	**$132,998,495**	

[1]Includes: Escalation (19.0%), CE OH (13.25%), A&S (2.53%), PT&P (39.35%), AFDC (14.73%), and Contingency (30%)

Project Risks and Mitigation Plan

Risk 1:
Delays due to resource/support coordination.

Mitigation Plan 1:
Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Risk 2:
Material Availability Issues

Mitigation Plan 2:

Engineering will work with Supply Chain to establish a cohesive plan that aligns with vendor lead times. Stay engaged with vendors to ensure lead times are maintained, and adjust the plan as needed if shortages are encountered.

Risk 3:
Unforeseen inclement climate events that will impact planned outages and overall schedule.

Mitigation Plan 3:
Incorporate potential disruptions in the overall planning schedule and identify alternative outage dates, should planned outage dates be cancelled.

Technical Evaluation / Analysis
N/A

Project Relationships (if applicable)
This project results from the implementation of an interim load relief solution at Brownsville No. 1 that transfers 60 MW from Brownsville No. 1 to Glendale in 2026. This transferred load, which continues to grow, leads to capability utilization at Glendale above 90% in the last half of the 10-year forecast period.

This project is also sequential and complimentary to the establishment of the Gateway Park Area Station by 2028, a new indoor 27kV area substation that will be arranged in a double SYN bus configuration and with five 138/27kV transformer banks. The station will be supplied from the 345kV Brooklyn Energy Hub.

3. Funding Detail ($000)

Historic Spend

	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Test Year (O&M Only)*	Forecast 2024
O&M	$0	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	N/A	$0
Capital	$0	$0	$0	$0	N/A	$0

2025-2029 Request:
Total Request by Year:

	2025	2026 (RY1)	2027 (RY2)	2028 (RY3)	2029
O&M	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	$0
Capital (Total)	$0	$6,650	$14,300	$59,850	$32,250
Labor	$0	$1,649	$3,567	$15,024	$8,045
M&S	$0	$1,682	$3,589	$14,964	$8,093
Contract Svcs.	$0	$2,002	$4,306	$17,957	$9,712
Other	$0	$267	$574	$2,394	$1,295
Overheads	$0	$1,050	$2,264	$9,511	$5,105

*The test year runs from 10/1/23 to 9/30/24.

Central Operations / Substation Operations

2025-2029

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Fox Hills 33kV – 4th Transformer & 138kV Supply Feeder	
Project/Program Manager: Partha Roy	**Project/Program Number (Level 1):** 27724607
Status: ☐ **Initiation/Planning** ☐ **In-Progress (Projects Only)** ☐ **On-going (Programs Only)**	
Estimated Start Date: 2026	**Estimated Date In Service:** 2030
2025-2029 Funding Request ($000) **Capital:** $39,000 **O&M:** $0	

Work Description:
This project is designed to increase the capability at the Fox Hills 33kV substation to mitigate risks associated with future load growth. This project will establish a fourth 138/33kV transformer bank at Fox Hills 33kV Substation, to be supplied by a new 138kV feeder. Additionally, it will create a new 33kV bus section to create an additional point of supply for future 33kV loads.

Major scopes of work to be completed under this project include:

- Install new foundations for the following: breakers 22S, 7X, 72S, & 73S, surge arresters, disconnect switches, pothead stands, relocated 600KVAR shunt reactor on feeder 33R27, and new prefabricated relay enclosure
- Install new 33 kV breaker 7X and create new 33 kV bus section 7X
- Relocate Feeder 33R27 to new bus section 7X and install new breaker 72S
- Install new foundations and spill containment for transformer TR5.
- Rename and repurpose existing breaker 73S (formally 72S) to TR5 and install new 138/33 kV transformer TR5
- Install new below grade duct bank for supply feeder from 138kV to 33kV station.
- Connect new 138 kV supply feeder to Fox Hills 138 between breakers 9N and 9X
- Install new 33 kV breaker 22S in section 2S to create additional point of supply for 33 kV loads
- Install new prefabricated relay enclosure with panels

Major or long lead equipment requirements for the project include, but are not limited to:

Major Equipment Type	Number to be Purchased
93 MVA 138/35 kV Transformer	1 each
138 kV 3Ø Disconnect Switch with Ground	1 each
138 kV 3Ø Feeder Disconnect	1 each
138kV Surge Arresters	1 each
Prefabricated relay enclosure with 10 panels	1 each

Engineering and long lead equipment procurement will begin in 2026 for this project and construction is expected to begin in 2028 and to be completed in 2030. The estimated timeline to complete the major scopes of work associated with the project is below. This timeline is subject to change at any time, as the Company optimizes the project schedule and incorporates impacts of other projects and system performance.

Project Timeline / High-level Work Plan

	2026				2027				2028				2029				2030			
Project Work Stream / Scope:	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Authorization	◆																			
Pre-Planning / Conceptual Scope and Estimate	■																			
Appropriations		■	■																	
Procurement: Land, Equipment, and Contracting																				
Procure Major Equipment				■	■	■	■	■	■	■	■									
Award Contracts						■	■	■	■											
Engineering		■	■	■	■															
Permitting				■	■	■	■	■												
Site Preparation (including demolition)							■	■	■											
Construction:																				
Install Major Substation Equipment										■	■	■	■	■	■	■				
Install Auxiliary Equipment															■	■				
Construct new Feeder										■	■	■	■	■						
Testing and Commissioning																	■	■		
Energization / In-Service																		◆		

Justification Summary:
The latest load forecast shows significant load growth in the Fox Hills load area (including growth related to the Staten Island Ferry electrification project) compared to last year's forecast, resulting in load constraints within the 10-year window. Load projections in the 2024 - 2033 Ten Year Load Relief Program indicate that the station's capability will be exceeded by 3 MW (101%) in 2030 if no actions are taken, with station capability exceedances increasing as the load continues to grow in ensuing years. The rapid load growth in the network over the next few years is primarily driven by electrification of Staten Island Ferry with associated economic activity in the area expected to continue.

Installation of a fourth 138kV/33kV transformer and an additional 138kV supply feeder will increase the capability at Fox Hills by 118 MW, returning station margins to acceptable levels.

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Fox Hills 33 kV	205	209	214	219	221	223	241	242	243	244
Electrification Adjustment	1	2	3	4	6	7	9	13	18	23
Other Adjustments	-4	-8	-8	-10	-13	-15	-11	-12	-13	-14
Net Load	202	203	209	213	214	215	239	243	248	253
Current Capability	236	236	236	236	236	236	236	236	236	236
Forecasted Load as % of Current Capability	86%	86%	89%	90%	91%	91%	101%	103%	105%	107%
Capability with Expansions	236	236	236	236	236	236	354	354	354	354
% of Capability	86%	86%	89%	90%	91%	91%	68%	69%	70%	71%

Relationship to Broader Company Plans, Initiatives and the NYS Climate Leadership and Community Protection Act
This project will not directly impact greenhouse gas emissions.

This project will strengthen the overall transmission system and networks served by the Fox Hills Area Substation including any disadvantaged communities in the area or downstream from this project.

Meeting New York's CLCPA goals will ultimately require the Company to build system capacity for an anticipated increase in load growth. With electrification of the City, as we move away from a carbon economy, we will require capacity in the affected networks to accommodate unprecedented

load growth. Rapid load growth has the potential to leave the Company in a difficult position to address all the relief and reliability challenges in the near future.

This project is a core investment that enables the Company to continue to provide safe and reliable service, even as the nature of the grid changes. This aligns with Con Edison's strategic objective of providing world-class safety, reliability, and security, while managing the equity challenges of the energy transition.

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection:

One alternative solution considered for this project was to establish a new 33kV substation, supplied by Fox Hills 138kV. Although this is feasible and allows for load relief through 2042 based on the current forecast, there are various factors including significant costs and time constraints to rely on this option. Furthermore, should the load forecast increase, the fifth transformer and 138kV feeder will still be operationally required.

In addition, all system expansion projects will be reviewed for non-wires solutions (NWS) in accordance with the suitability criteria outlined in the Distributed System Platform (DSP). The current forecast requires at least 17MW of REV NWS to defer fourth transformer beyond 2033. However, future demand forecasts are subject to change based on actual peak summer load conditions as well as economic trends and are likely to present significant challenges in achieving required customer side load reductions to provide adequate solutions in the face of rapid network load growth. Changes in future forecasts and planning may result in the advancement of addressing system overloads.

Risk of No Action

If no action is taken to alleviate forecasted capability exceedances at the Fox Hills 33kV substation, there is a high risk of overloading the substation equipment during peak load conditions. Exceeding the rated capacity of the substation could result in load shedding if contingencies occur during peak loading conditions resulting in customer outages, increasing the risk of equipment failure, and adversely impacting the community served, as well as encountering the potential inability of maintaining reliable system power flow controls, system reliability and resiliency concerns.

Non-Financial Benefits

This project will provide the necessary load relief for overloaded feeders and equipment, which will ensure the continuity of reliable service in the areas served by the Fox Hills Substation.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)
N/A

2. Major financial benefits
N/A

3. Basis for estimate
This estimate is based on an order of magnitude estimate of project costs based on a conceptual design and historical costs for similar scopes of work. High-level estimates of total costs, by primary spend category, are shown below, including escalation, overheads, and contingency.

	Estimated Direct Costs	*Esc., OH, & Other Loading*[1]	*Estimated Total*	*% of Total*
01-Labor	$ 3,342,520	$ 5,340,416	$ 8,682,936	26.8%
02-MSH	$ 7,186,007	$ 6,909,665	$14,095,672	43.6%
03-Cont Svcs	$ 4,117,574	$ 3,959,231	$ 8,076,805	25.0%
09-Other	$ 754,758	$ 725,733	$ 1,480,491	4.6%
Total	**$ 15,400,860**	**$ 16,935,044**	**$32,335,903**	

[1]Includes: Escalation (14%), CE OH (13.25%), A&S (2.53%), PT&P (39.35%), AFDC (9.09%), and Contingency (30%)

Project Risks and Mitigation Plan

Risk 1: Delays due to resource/support coordination

Mitigation Plan 1: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Risk 2: Material Availability Issues

Mitigation plan 2: Engineering will work with Supply Chain to establish a cohesive plan that aligns with vendor lead times. Stay engaged with vendors to ensure lead times are maintained, and adjust the plan as needed if shortages are encountered.

Technical Evaluation / Analysis

Forecasted loads for Fox Hills in 2030 are approximately 239MW, which exceeds the station's 236MW capability by 3MW or 1.25%. The overloads will increase in subsequent years as network load continues to grow. The growth in the Fox Hills load area is mostly due to electrification of Staten Island Ferry (approx. 16MW). To accommodate the forecasted load under a design N-2 contingency, a new 138/33kV transformer and new 138kV supply feeder are required at the Fox Hills Substation.

Project Relationships (if applicable)

N/A

3. Funding Detail ($000)

Historic Spend

	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Test Year* (O&M Only)	Forecast 2024
O&M	$0	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	N/A	$0
Capital	$0	$0	$0	$0	N/A	$0

2025-2029 Request:

Total Request by Year:

	2025	2026 (RY1)	2027 (RY2)	2028 (RY3)	2029
O&M	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	$0
Capital (Total)	$0	$8,000	$8,000	$6,000	$17,000

Labor	$0	$1,977	$2,008	$1,506	$4,267
M&S	$0	$2,041	$2,000	$1,500	$4,250
Contract Svcs.	$0	$2,401	$2,400	$1,800	$5,101
Other	$0	$320	$320	$240	$680
Overheads	$0	$1,261	$1,272	$954	$2,702

*The test year runs from 10/1/2023 to 9/30/2024

Central Operations / Substation Operations
2025-2029

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Parkchester No. 1 5th Transformer 9S and Supply Feeder 38X05	
Project/Program Manager: Partha Roy	**Project/Program Number (Level 1):** 27809976
Status: ☒ **Initiation/Planning** ☐ **In-Progress (Projects Only)** ☐ **On-going (Programs Only)**	
Estimated Start Date: 2026	**Estimated Date In Service:** 2028
2025-2029 Funding Request ($000) **Capital:** $124,900 **O&M:** $0	

Work Description:
This project is designed to increase the capability at Parkchester No. 1 substation by 76 MW to mitigate reliability risks associated with the projected load growth as a result of the electrification. This project will establish a fifth 138/13.8kV transformer bank at Parkchester No. 1 Substation, to be supplied by a new 138kV feeder originating from E179th St. 138kV Substation.

Major scopes of work to be completed under this project include:

- Install new 138kV feeder 38X05 from existing bus section BTEW at E179th St. to new transformer TR 9S at Parkchester No. 1 Substation.
  - Install new below grade duct bank for supply feeder from E179th St. Substation to Parkchester No. 1 Substation.
  - Connect new 38X05 supply feeder to E179th St. Substation between breakers BTW and BTE.
  - Install new 138kV disconnect and ground switch, CCPDs and surge arresters at E179th St. Substation.
  - Install new prefabricated relay enclosure with panels at E179th St. Substation.
- Install new transformer TR 9S at Parkchester No. 1 Substation.
  - Install new foundations and spill containment for transformer TR 9S.
  - Install new 13kV secondary bus connecting to existing Syn Bus Tie.
  - Install new 138kV circuit switcher and ground switch.
  - Install new 13kV circuit breaker cubicle with PT compartment and associated relay panels.
- Install new foundations for the following:
  - E179th St – Feeder 38X05 potheads, 138kV disconnect & ground switches, CCPDs, surge arresters, relay enclosure.
  - Parkchester No. 1 – 138/13.8kV Transformer TR 9S, 138kV circuit switcher, 13kV PT and circuit breaker cubicle.

Major or long lead equipment requirements for the project include, but are not limited to:

Major Equipment Type	Number to be Purchased
138 kV 3Ø Feeder Disconnect with Ground Switch	1 each
138 kV 3Ø CCPDs	1 each
Prefabricated relay enclosure with 5 panels	1 each
65 MVA 138/13.8 kV Transformer	1 each
138kV Circuit Switcher with Ground Switch	1 each
13kV Switchgear – Circuit breaker, PT, relay cubicle	1 each

Engineering, equipment procurement and construction will begin in 2026 for this project, with a targeted completion date in 2028. However, due to challenges in the transmission feeder route which may include complexities of a river crossing, the completion date for this project may occur in 2029 and prior to the required deterministic load relief need date of 2030. To reduce procurement lead time, the project might utilize a spare transformer along with associated equipment. This timeline is subject to change at any time, as the Company optimizes the project schedule and incorporates impacts of other projects and system performance.

Justification Summary:

This project is part of the solution being implemented to reduce the reliability risk on the Parkchester No. 1 and Parkchester No. 2 13kV Area Substations. Based on the latest 2024 Company Forecast, the station capability at Parkchester No. 1 will be over 100% utilized by 2030. Installation of a fifth Transformer at Parkchester No.1 with a 138kV supply feeder from E179th St substation would increase the station capability by 76MW.

Furthermore, the Company has elected to incorporate a transmission probabilistic reliability assessment (TPRA) method of planning where risk of load drops is quantified to prioritize substation work in the riskiest stations to maintain system reliability. The TPRA model analyzes residual system risk in conjunction with supporting the deterministic planning method. The Company has developed, updated and utilized this model for the past 20 years to prioritize and optimize reliability projects by quantifying load drop risks under different load growth scenarios. TPRA risk analysis shows that both Parkchester No. 1 and No. 2 substations have high risk of dropping load in year 2028 and beyond due to high projected load as discussed above and configurational challenges in system design. Moreover, the load forecast uncertainty adds to the risk. Given the potential of faster growth in load and projected load drop risk, it is prudent to add capacity by installing additional transformers at both stations proactively in 2028. With the 5th transformer the load drop risk at Parkchester No. 1 is projected to be close to zero in 2028, however, as the load may increase further in the 2030's, the risk may return in later years, demanding more capacity addition in this load area.

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Parkchester No. 1										
Southeast Bronx	219	224	228	231	232	234	235	236	237	238
Electrification Adjustment	2	3	7	12	17	23	29	36	43	50
Other Adjustments	-12	-12	-14	-16	-15	-13	-13	-14	-15	-14
Net Load	209	215	221	227	234	244	251	258	265	274
Capability	236									
Overload						8	15	22	29	38

Following completion of this work, the substation capability increases to 312 MW.

Parkchester No. 1	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Southeast Bronx	219	224	228	231	232	234	235	236	237	238
Electrification Adjustment	2	3	7	12	17	23	29	36	43	50
Other Adjustments	-12	-12	-14	-16	-15	-13	-13	-14	-15	-14
Net Load	209	215	221	227	234	244	251	258	265	274
Capability	236					312				

The capacity expansion at Parkchester No. 1 will support a variety of new loads, and the upgrade in the Southeast Bronx load area is specifically required to enable transportation and building electrification. This project will not only aid in transportation electrification but also support building decarbonization and State goals and regulations by providing capacity for customers to connect to the grid. The rapid load growth in the Southeast Bronx network over the next several years is primarily driven by electrification and associated economic activity in the area, trends expected to continue. While this load pocket does not include the Zerega Avenue hotspot, which will be supported by Parkchester No. 2, it does include (1) almost one thousand additional school buses and utility trucks, (2) thousands of personal and commercial fleet vehicles in the area that must electrify to meet policy mandates, and (3) several specific customer electrification plans; this project enables the ability to serve future expected load.

Relationship to Broader Company Plans, Initiatives and the NYS Climate Leadership and Community Protection Act

This project will strengthen the reliability of the Con Edison electric system and networks served by the Parkchester No. 1 Substation including Disadvantaged Communities downstream from this project.

This project was also included in the Company's Proactive Planning proceeding (Case # 24-E-0364) Urgent Projects Filing to support grid infrastructure needs for transportation and building electrification. If the requested funding is granted in the Proactive Planning proceeding, the capital funding requested in this proceeding will be adjusted, as needed.

2. Supplemental Information

Alternatives

Alternative 1

Load Transfer – One alternative solution considered was a 70 MW load transfer from Parkchester No. 1 to Parkchester No. 2. At a cost of over $230 million, this solution was deemed too costly. Furthermore, probabilistic analysis shows that 70MW load transfer would lower the load drop risk at Parkchester No. 1 at the expenses of increased risk at Parkchester No. 2, meaning this load transfer will not reduce the total risk of Parkchester load pocket.

Alternative 2

Non-Wires Solutions/Energy Efficiency Measures – In addition, all system expansion projects are reviewed for non-wires solutions (NWS) in accordance with the suitability criteria outlined in the Distributed System Platform (DSP). The current forecast requires at least 38 MW of REV NWS to defer fifth transformer beyond 2034. However, future demand forecasts are subject to change based on actual peak summer load conditions as well as economic trends, factors that are likely to present significant challenges in achieving required customer side load reductions to provide adequate solutions in the

face of rapid network load growth. Changes in future forecasts and planning may result in the advancement of projects addressing system overloads.

Risk of No Action

If no action is taken to alleviate the forecasted reliability risk at the Parkchester No. 1 substation, there is a high risk of overloading the substation equipment during peak load conditions. Exceeding equipment rated capacity of the substation could result in load shedding if contingencies occur during peak loading conditions. This load shedding could result in customer outages, increased risk of equipment failure, and adverse impact to the community served, as well as the potential inability to maintaining reliable system power flow controls, system reliability and resiliency concerns.

There is a real risk of delays in providing service to customers, impacting critical customer plans, and delaying achievement of intermediate climate policy goals related to transportation and building electrification as well as delaying improvements in the air quality in these communities.

Non-Financial Benefits

This project will provide the necessary load relief for overloaded feeders and equipment, benefiting the reliability of service in the areas served by the Parkchester No. 1 Substation.

This project will also add the capacity needed to support transportation and building electrification, which will improve air quality, noise pollution, and reduce greenhouse gas emissions. Based on Con Edison's internal analysis, by 2040 this project will support charging of light-, medium-, and heavy-duty vehicles and electrification of heating systems to avoid 455 thousand tons of carbon dioxide equivalent (CO2e) that year, with a total avoided emissions of 3,480 thousand CO2e from the in-service date through 2040, and even more in the years beyond.

The grid readiness resulting from this project will signal to customers looking to electrify in compliance with policy mandates that the grid is ready to accommodate their load requests without delaying their plans. This project will thus strengthen relationships with our customers and communities. By proactively building out the grid to be ready for new loads, Con Edison is increasing customer trust and a better customer experience to enable a smoother and expedited new business process.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)
N/A.

2. Major financial benefits
N/A

3. Basis for estimate
The estimate is based on an order of magnitude estimate of project costs based on a conceptual design and historical costs for similar scopes of work. High-level estimates of total costs, by primary spend category, are shown below, including escalation, overheads, and contingency.

	Estimated Direct Costs	*Esc., OH, & Other Loading*[1]	*Estimated Total*	*% of Total*
01-Labor	$ 8,622,178	$ 12,692,628	$ 21,314,806	16.8%
02-MSH	$ 16,731,957	$ 14,501,260	$ 31,233,217	24.6%

03-Cont Svcs	$ 35,127,497	$ 30,444,317	$ 65,571,81451.7%
09-Other	$ 4,661,400	$ 4,039,944	$ 8,701,3446.9%
Total	**$ 65,143,032**	**$ 61,678,149**	**$126,821,181**

[1]Includes: Escalation (11.00%), CE OH (13.25%), A&S (2.53%), PT&P (39.35%), AFDC (6.62%), and Contingency (30%)

Project Risks and Mitigation Plan

Risk 1:

The vicinity of the above ground trains can make it difficult to find crossings/lanes for feeders.

Mitigation Plan 1:

Confirm via surveys that enough lanes are available for the feeder band runs. Obtain all permits ahead of time. Explore other options to go under any obstacles like trains.

Technical Evaluation / Analysis

N/A

Project Relationships (if applicable)

This project is related to Parkchester No. 2 TR13 & B/S 13A & 13B Installation and new supply feeder project. Both substation projects, Parkchester No. 1 5th Transformer 9S and Supply Feeder 38X05 and the Parkchester No. 2 TR13 & B/S 13A & 13B Installation, are necessary to provide area substation capacity and reliability to feed the Southeast Bronx and Northeast Bronx, respectively. While the Zerega Avenue hotspot is currently part of the Southeast Bronx network, fed by Parkchester No. 1, the Urgent Projects infrastructure would supply feeders to Zerega Avenue from Parkchester No. 2. Going forward, Parkchester No. 1 will still supply vehicle and building electrification loads within the Southeast Bronx network near Zerega Avenue, but outside the Zerega Avenue hotspot.

This project is required to support the projected electrification loads and ensure the capacity exists and service reliability is maintained for this load. Thus, it is included in the Company's Proactive Planning proceeding (Case # 24-E-0364) Urgent Projects Filing.

3. Funding Detail ($000)

Historic Spend

	Actual 2020	**Actual 2021**	**Actual 2022**	**Actual 2023**	**Test Year* (O&M Only)**	**Forecast 2024**
O&M	$0	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	N/A	$0
Capital	$0	$0	$0	$0	N/A	$0

2025-2029 Request:

Total Request by Year:

	2025	**2026 (RY1)**	**2027 (RY2)**	**2028 (RY3)**	**2029**
O&M	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	$0

Capital (Total)	$0	$10,000	$60,140	$49,760	$5,000
Labor	$0	$1,446	$9,055	$6,912	$0
M&S	$0	$2,410	$15,091	$11,519	$0
Contract Svcs.	$0	$2,892	$18,109	$13,823	$0
Other	$0	$386	$0	$0	$0
Overheads	$0	$2,866	$17,885	$17,506	$5,000

*The test year runs from 10/1/2023 to 9/30/2024

Central Operations / Substation Operations
2025-2029

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Millwood West Install Third Transformer with its 138kV Supply Feeder	
Project/Program Manager:	**Project/Program Number (Level 1):** 28016995
Status: ☒ **Initiation/Planning** ☐ **In-Progress (Projects Only)** ☐ **On-going (Programs Only)**	
Estimated Start Date: 2026	**Estimated Date In Service:** 2031
2025-2029 Funding Request ($000) **Capital:** $44,000 **O&M:** $0	

Work Description:

This project is designed to increase the capability at the Millwood West substation to accept Ossining West Area Substation load transfer of approximately 20 MW in 2031. This project will establish a third 138/33kV transformer bank at Millwood West Substation, to be supplied by a new 138kV feeder.

Major scopes of work to be completed under this project include:

- Install and connect new 138kV/13kV Transformer TR3 to the spare position at Bus Section 8W at Disc. Switch F8W1.
- Install associated 138kV Circuit Switcher & Interrupter CS-3, PT's and surge arrester.
- Replace existing 13kV BT3-4 with two (2) new 13kV breakers 3T-3N and 3T-4N.
- Install new foundations and spill containment for Transformer TR3.
- Install new foundations for breakers, circuit switchers, PT's and surge arresters.
- Install new strain bus support structure.

Major or long lead equipment requirements for the project include, but are not limited to:

Major Equipment Type	Number to be Purchased
65 MVA 138/13 kV Transformer	1 each
138kV Surge Arresters	1 each
138kV Circuit Switcher & Interrupter	1 each
13kV Circuit Breaker	2 each

Engineering and long lead equipment procurement will begin in 2026 for this project, and construction is expected to begin in 2029 and be completed in 2031. This timeline is subject to change at any time, as the Company optimizes the project schedule and incorporates impacts of other projects and system performance.

Project Timeline / High-level Work Plan	2026				2027				2028				2029				2030				2031			
Project Work Stream / Scope:	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Authorization				◆																				
Pre-Planning / Conceptual Scope and Estimate					■																			
Appropriations					■	■																		
Procurement: Land, Equipment, and Contracting							■	■	■	■	■	■	■	■	■	■	■	■	■					
Engineering					■	■	■	■	■	■	■	■	■	■										
Permitting														■	■									
Site Preparation (including demolition)															■	■								
Construction																■	■	■	■	■				
Testing and Commissioning																				■	■			
Energization / In-Service																						◆		

Justification Summary:

This project is part of the solution being implemented to alleviate forecasted load constraints on the Ossining West Area Substation. Based on forecasted load growth for the Ossining West load area included in the 2024 Load Relief Program (LRP), station capability at Ossining West will be exceeded by 2031.

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Ossining West	72	76	79	81	81	82	63	64	64	65
Electrification Adjustment	1	3	5	7	9	11	11	12	14	15
Other Adjustments	-2	-3	-4	-5	-5	-4	-4	-4	-4	-4
Net Load	71	76	80	83	85	89	70	72	74	76
Capability	89									
Low Voltage Capability (2)	107									
1-Hour Capability	100									

Transferring approximately 20 MW (2031) of load from Ossining West to Millwood West alleviates this forecasted constraint.

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Millwood West	69	71	72	74	74	75	95	95	96	96
Electrification Adjustment	1	2	3	5	7	10	15	19	22	25
Other Adjustments	-2	-3	-4	-5	-5	-5	-6	-7	-7	-7
Net Load	68	70	71	74	76	80	104	107	111	114
Capability (1)	83						162			
Low Voltage Capability (2)	115									
1-Hour Capability	90									

Based on forecasted load growth for Ossining West Area Substation, the station would have its station capability surpassed in 2031. Although transferring this load from the Ossining West to the Millwood West relieves the forecasted load constraint on the Ossining West, it causes a load constraint at the Millwood West.

This project is needed to increase the capability at the Millwood West Area Substation so that the Ossining West load transfer can be added to Millwood West without causing a constraint on the area substation. The additional equipment being installed by this project increases the capability of the Millwood West Area Substation from 83 MW to 162 MW in 2031.

Relationship to Broader Company Plans, Initiatives and the NYS Climate Leadership and Community Protection Act

This project will not directly impact greenhouse gas emissions.

This project will strengthen the overall transmission system and networks served by the Millwood West Area Substation including any DACs in the area or downstream from this project.

Meeting New York's CLCPA goals will ultimately require the Company to build system capacity for an anticipated increase in load growth. With electrification of the City, as we move away from a carbon economy, we will require capacity in the affected networks to accommodate unprecedented load growth. Rapid load growth has the potential to leave the Company in a difficult position to address all the relief and reliability challenges in the near future.

This project is a core investment that enables the Company to continue to provide safe and reliable service, even as the nature of the grid changes. This aligns with Con Edison's strategic objective of providing world-class safety, reliability, and security, while managing the equity challenges of the energy transition.

2. Supplemental Information

Alternatives

Alternative 1

No Load Transfer – An alternative solution to this project which was considered was the installation of a fifth transformer at Ossining West Street Area Station itself. While this would eliminate the need for a load transfer, the station was not originally designed with the available future space for an additional transformer. To achieve this, the existing station, including security fence and grounding grid would have to be expanded, adding significant costs.

Risk of No Action

If no action is taken to alleviate forecasted capability exceedances at the Ossining West Substation due to load growth, there is a high risk of overloading the substation equipment during peak load conditions. Exceeding the rated capacity of the substation could result in load shedding if contingencies occur during peak loading conditions resulting in customer outages, increasing the risk of equipment failure, and adversely impacting the community served, as well as encountering the potential inability of maintaining reliable system power flow controls, system reliability and resiliency concerns.

Non-Financial Benefits

This project will facilitate the necessary load relief for overloaded feeders and equipment, which will ensure the continuity of reliable service in the areas served by the Ossining West Substation.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)
N/A

2. Major financial benefits
N/A

3. Basis for estimate

An estimate for this project has not yet been completed. The estimated cost has been based on an order of magnitude estimate for a project that is similar in scope to this project costs based, the Parkchester No. 2 TR13 & B/S 13A & 13B Installation project. High-level estimates of the total costs based on the proxy project, by primary spend category, are shown below, including escalation, overheads, and contingency.

	Estimated Direct Costs	*Esc., OH, & Other Loading*[1]	*Estimated Total*	*% of Total*
01-Labor	$ 7,033,761	$ 11,599,290	$ 18,633,051	42.0%
02-MSH	$ 9,785,163	$ 9,788,405	$19,573,568	44.2%
03-Cont Svcs	$ 1,096,503	$ 1,096,867	$2,193,370	5.0%
09-Other	$ 1,943,828	$ 1,944,472	$3,888,300	8.8%
Total	**$19,859,256**	**$24,429,032**	**$44,288,288**	

[1] Includes: Escalation (31%), CE OH (13.25%), A&S (2.53%), PT&P (39.35%), AFDC (2.32%), and Contingency (23%)

Project Risks and Mitigation Plan

Risk 1:
Delays due to resource/support coordination

Mitigation Plan 1:
Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Risk 2:
Material Availability Issues

Mitigation Plan 2:
Engineering will work with Supply Chain to establish a cohesive plan that aligns with vendor lead times. Stay engaged with vendors to ensure lead times are maintained, and adjust the plan as needed if shortages are encountered.

Technical Evaluation / Analysis

The need for this project is based on the 2025-2034 Area Substation and Sub-transmission Feeder Ten-Year Load Relief Program (LRP). The LRP reflects increased forecasted demand from transportation (EVs) and building electrification (BE), as well as load reductions projected to be achieved through Energy Efficiency (EE), Organic EE, Conservation Voltage Optimization (CVO), Demand Response (DR), and the integration of Distributed Generation (DG), Solar Photovoltaics (PV) and Battery Storage.

Project Relationships (if applicable)

This project facilitates the transfer of load from the Ossining West Area Substation to the Millwood West Area Substation. The actual transfer of the load will be implemented under a separate electric distribution project, the Ossining West to Millwood West transfer.

3. Funding Detail ($000)

Historic Spend

	Actual 2020	**Actual 2021**	**Actual 2022**	**Actual 2023**	**Test Year* (O&M Only)**	**Forecast 2024**

O&M	$0	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	N/A	$0
Capital	$0	$0	$0	$0	N/A	$0

2025-2029 Request:

Total Request by Year:

	2025	**2026 (RY1)**	**2027 (RY2)**	**2028 (RY3)**	**2029**
O&M	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	$0
Capital (Total)	$0	$3,000	$3,000	$8,000	$30,000
Labor	$0	$709	$657	$1,130	$1,935
M&S	$0	$756	$756	$2,500	$10,800
Contract Svcs.	$0	$870	$770	$2,600	$12,000
Other	$0	$120	$120	$248	$899
Overheads	$0	$545	$697	$1,522	$4,366

*The test year runs from 10/1/2023 to 9/30/2024

Central Operations / Substation Operations
2025-2029

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Cedar Street Load Relief-Install 4th Transformer, New 138 kV Supply Feeder and 20 MVAR Capacitor Bank	
Project/Program Manager: Partha Roy	**Project/Program Number (Level 1):** 27724611
Status: ☒ **Initiation/Planning** ☐ **In-Progress (Projects Only)** ☐ **On-going (Programs Only)**	
Estimated Start Date: 2026	**Estimated Date In Service:** 2031
2025-2029 Funding Request ($000) **Capital:** $152,420 **O&M:** $0	

Work Description:
This project is designed to increase the capability at the Cedar Street substation to accept Washington Street Area Substation load transfer of approximately 50 MW (50MW current / 55 MW 2031) in 2031. This project will establish a fifth 138/33kV transformer bank at Cedar Street Substation, to be supplied by a new 138kV feeder. Additionally, it will create a new 13kV bus section to create an additional point of supply for future 13kV loads. The project will also include the installation of a 20MVAR capacitor bank at the substation.

Major scopes of work to be completed under this project include:

- Replace the existing breaker 10N at Dunwoodie North with a new 10N/10X PASS double breaker (with disconnect switches). Install new foundations for 138kV GIS PASS double breaker, pothead stand and disconnect switch.
- Create a new 138kV feeder 38W05 at Dunwoodie North with disc switch. Run new feeder 38W05 (approx. 4 miles) to Washington Street. Install Wye joint or additional pot heads to extend feeder 38W05 (approx. 3.5 miles) from Washington Street to Cedar Street.
- Connect and install fourth 138kV/13kV transformer into service at Cedar Street Substation along with associated fire protection. Install two new bus switchgear sections 4N and 4S with four 13 kV feeders each and connect to extension of syn busses. Install new SPCC moat, foundation and firewalls for Bank 4. Install new foundation for new switchgear sections and structural supports for bus duct extensions.
- Install third area substation 20MVAR capacitor bank for voltage support due to additional load

Major or long lead equipment requirements for the project include, but are not limited to:

Major Equipment Type	Number to be Purchased
65 MVA 138/13 kV Transformer	1 each
138 kV GIS PASS Double Breaker (with disc sws)	1 each
138 kV 3Ø Feeder Disconnect	1 each
138kV Surge Arresters	1 each

20MVAR capacitor bank	1 each

Engineering and long lead equipment procurement will begin in 2026 for this project, and construction is expected to begin in 2029 and be completed in 2031. The estimated timeline to complete the major scopes of work associated with the project is below. This timeline is subject to change at any time, as the Company optimizes the project schedule and incorporates impacts of other projects and system performance.

Project Timeline / High-level Work Plan

	2027				2028				2029				2030				2031			
Project Work Stream / Scope:	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Authorization	◆																			
Pre-Planning / Conceptual Scope and Estimate	■																			
Appropriations		■	■																	
Procurement: Land, Equipment, and Contracting																				
Procure Major Equipment				■	■	■	■	■	■	■	■									
Award Contracts						■	■	■	■											
Engineering		■	■	■	■															
Permitting				■	■	■	■	■												
Site Preparation (including demolition)							■	■	■											
Construction:																				
Install Major Substation Equipment										■	■	■	■	■	■	■				
Install Auxiliary Equipment															■	■				
Construct new Feeder										■	■	■	■	■						
Testing and Commissioning																	■	■		
Energization / In-Service																		◆		

Justification Summary:
This project is part of the solution being implemented to alleviate forecasted load constraints on the Washington Street Area Substation. Based on forecasted load growth for the Washington Street load area included in the 2024 Load Relief Program (LRP), station capability at Washington St. will be exceeded by 2033.

Previously, Con Edison utilized purely deterministic processes to assess load relief need. This process resulted in "just-in-time" project completion as the year the energy forecast's projected demand approaches a substation's capability. Forecast uncertainty due to the dynamic energy landscape driven by the Climate Leadership and Community Protection Act (CLCPA) and NY state policies have required the Company to adapt the existing planning process to capture other elements of risk.
For this reason, the Company has elected to incorporate a probabilistic method of planning where risk of customer interruption is modeled to prioritize substation work in the riskiest stations and maintain system reliability.

Based on forecasted load growth for Washington Street Area Substation, the station would have its station capability surpassed in 2033. With "just-in-time" planning, temporary emergency load transfers (1-Hour Capability) for 2033 – 2034 would be utilized until exhausted in 2035 when a 50 MW load transfer is required to provide load relief. However, probabilistic assessment identified Washington Street Area Substation to have an elevated risk of customer interruption as it approaches its substation capability. For this reason, the project timeline has been risk adjusted at Washington Street Area Substation from 2035 to 2031.

Washington Street w/o Load transfe	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Washington St. Network	189	190	193	195	196	197	198	198	199	199	200	200	201	201	201	202	202	203	203	203
Electrification Adjustment	1	9	10	11	13	15	17	23	30	38	45	53	60	68	75	82	89	95	99	104
Other Adjustments	0	-1	-2	-3	-4	-5	-2	-2	-3	-3	-3	-3	-3	-4	-5	-5	-2	-2	0	0
Net Load	190	198	201	203	205	207	213	219	226	234	242	250	258	265	271	279	289	296	302	307
Capability	231	231	231	231	231	231	231	231	231	231	231	231	231	231	231	231	231	231	231	231
Net Load as % of current capability	82%	86%	87%	88%	89%	90%	92%	95%	98%	101%	105%	108%	112%	115%	117%	121%	125%	128%	131%	133%
1-Hour Capability										245	245	245	245	245	245	245	245	245	245	245
Net Load as % of 1-Hour capability										96%	99%	102%	105%	108%	111%	114%	118%	121%	123%	125%

Transferring approximately 50 MW (2024) of load from Washington St. to Cedar St. alleviates this forecasted constraint.

50 MW load Transfer from Washington Street to Cedar Street	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Base Network MW Transferred	50	50	50	51	51	51	51	51	51	51	51	51	51
Electrification Transferred	6	8	10	11	13	15	17	19	21	22	24	25	26
Other Adjustments Transferred	-1	-1	-1	0	0	-1	-1	-1	-2	0	-1	0	0
Total Load Transferred	**55**	**57**	**59**	**62**	**64**	**65**	**67**	**69**	**70**	**73**	**74**	**76**	**77**

Washington Street w/2031 Load transfer	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Washington St. Network	189	190	193	195	196	197	198	148	149	149	149	149	150	150	150	151	151	152	152	152
Electrification Adjustment	1	9	10	11	13	15	17	17	22	28	34	40	45	51	56	61	67	71	74	78
Other Adjustments	0	-1	-2	-3	-4	-5	-2	-1	-2	-2	-3	-3	-2	-3	-4	-3	-2	-1	0	0
Net Load	190	198	201	203	205	207	213	164	169	175	180	186	193	198	202	209	216	222	226	230
Capability	231	231	231	231	231	231	231	231	231	231	231	231	231	231	231	231	231	231	231	231
Net Load as % of current capability	82%	86%	87%	88%	89%	90%	92%	71%	73%	76%	78%	81%	84%	86%	87%	90%	94%	96%	98%	100%

Although transferring this load from the Washington St. network to the Cedar St. network relieves the forecasted load constraint on the Washington St. Area Substation, it causes a load constraint at the Cedar St. Area Substation. An additional 20 MVAR capacitor bank will be installed at Cedar St. to provide voltage support.

Cedar St. (w/o 2031 Load Transfer)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Cedar St. Network	102	106	111	118	122	124	125	127	128	129
Electrification Adjustment	1	3	4	7	9	12	16	21	26	30
Other Adjustments	-3	-5	-6	-8	-9	-11	-11	-12	-13	-13
Net Load	100	104	109	117	122	125	130	136	141	146
Current Capability	168	168	168	168	168	168	168	168	168	168
Net Load as % of Current Capability	60%	62%	65%	70%	73%	74%	77%	81%	84%	87%
50 MW Load Transfer from Washington St. to Cedar St.								2031	2032	2033
Washington St. Network										
Base Network MW Transferred								50	50	50
Electrification Transferred								6	8	10
Other Adjustments Transferred								-1	-1	-1
Total Load Transferred								55	57	59
Cedar St (w/2031 Load Transfer)	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Cedar Street Network	102	106	111	118	122	124	125	177	178	179
Electrification Adjustment	1	3	4	7	9	12	16	27	34	40
Other Adjustments	-3	-5	-6	-8	-9	-11	-11	-13	-14	-14
Net Load	100	104	109	117	122	125	130	191	198	205
Current Capability	168	168	168	168	168	168	168	168	168	168
Net Load as % of Current Capability	60%	62%	65%	70%	73%	74%	77%	114%	118%	122%

This project is needed to increase the capability at the Cedar Street Area Substation so that the Washington Street load transfer can be added to the Cedar Street network without causing a constraint on the area substation.

Cedar St (w/2031 Load Transfer)	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Cedar Street Network	102	106	111	118	122	124	125	177	178	179
Electrification Adjustment	1	3	4	7	9	12	16	27	34	40
Other Adjustments	-3	-5	-6	-8	-9	-11	-11	-13	-14	-14
Net Load	100	104	109	117	122	125	130	191	198	205
Current Capability	**168**	168	168	168	168	168	168	168	168	168
Net Load as % of Current Capability	60%	62%	65%	70%	73%	74%	77%	114%	118%	122%
Capability w/fourth TR and supply feeder								**253**	253	253
Net Load as % of Increased Capability								75%	78%	81%
Increase in Capability		**85**								

Relationship to Broader Company Plans, Initiatives and the NYS Climate Leadership and Community Protection Act
This project will not directly impact greenhouse gas emissions.

This project will strengthen the overall transmission system and networks served by the Cedar Street Area Substation including any DACs in the area or downstream from this project.

Meeting New York's CLCPA goals will ultimately require the Company to build system capacity for an anticipated increase in load growth. With electrification of the City, as we move away from a carbon economy, we will require capacity in the affected networks to accommodate unprecedented load growth. Rapid load growth has the potential to leave the Company in a difficult position to address all the relief and reliability challenges in the near future.

This project is a core investment that enables the Company to continue to provide safe and reliable service, even as the nature of the grid changes. This aligns with Con Edison's strategic objective of providing world-class safety, reliability, and security, while managing the equity challenges of the energy transition.

2. Supplemental Information

Alternatives
Alternative 1
No Load Transfer – An alternative solution to this project which was considered was the installation of a fifth transformer at Washington Street Area Station itself. While this would eliminate the need for a load transfer, the station was not originally designed with the available future space for an additional transformer. To achieve this, the adjacent tenant would have to be vacated, and the existing station, including security fence and grounding grid would have to be expanded, adding significant costs. The new feeder routing from Dunwoodie North to Cedar St plan for a future tap to Washington Street to accommodate an additional transformer, if it is deemed required in the future.

Alternative 2

Non-Wires Solutions/Energy Efficiency Measures – In addition, all system expansion projects will be reviewed for non-wires solutions (NWS) in accordance with the suitability criteria outlined in the Distributed System Platform (DSP). The current forecast requires at least 17MW of REV NWS to defer fifth transformer beyond 2033. However, future demand forecasts are subject to change based on actual peak summer load conditions as well as economic trends and are likely to present significant challenges in achieving required customer side load reductions to provide adequate solutions in the face of rapid network load growth. Changes in future forecasts and planning may result in the advancement of addressing system overloads.

Risk of No Action

If no action is taken to alleviate forecasted capability exceedances at the Washington Street substation due to load growth, there is a high risk of overloading the substation equipment during peak load conditions. Exceeding the rated capacity of the substation could result in load shedding if contingencies occur during peak loading conditions resulting in customer outages, increasing the risk of equipment failure, and adversely impacting the community served, as well as encountering the potential inability of maintaining reliable system power flow controls, system reliability and resiliency concerns.

Non-Financial Benefits

This project will facilitate the necessary load relief for overloaded feeders and equipment, which will ensure the continuity of reliable service in the areas served by the Washington Street Substation.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)
N/A

2. Major financial benefits
N/A

3. Basis for estimate

This estimate is based on an order of magnitude estimate of project costs based on a conceptual design and historical costs for similar scopes of work. High-level estimates of total costs, by primary spend category, are shown below, including escalation, overheads, and contingency.

	Estimated Direct Costs	*Esc., OH, & Other Loading*[1]	*Estimated Total*	*% of Total*
01-Labor	$13,929,248	$23,313,762	$37,243,010	10%
02-MSH	$38,237,368	$39,113,936	$77,351,304	21%
03-Cont Svcs	$121,454,871	$124,618,238	$246,073,109	65%
09-Other	$7,943,242	$8,127,978	$16,071,220	4%
Total	**$181,564,729**	**$195,173,914**	**$376,738,643**	

[1]Includes: Escalation (13.1%), CE OH (13.25%), A&S (2.53%), PT&P (39%), AFDC (0%), and Contingency (30%)

Project Risks and Mitigation Plan

Risk 1:
Delays due to resource/support coordination

Mitigation Plan 1:
Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Risk 2:
Material Availability Issues

Mitigation Plan 2:

Engineering will work with Supply Chain to establish a cohesive plan that aligns with vendor lead times. Stay engaged with vendors to ensure lead times are maintained, and adjust the plan as needed if shortages are encountered.

Technical Evaluation / Analysis
The need for this project is based on the 2024-2033 Area Substation and Sub-transmission Feeder Ten-Year Load Relief Program (LRP). The LRP reflects increased forecasted demand from transportation (EVs) and building electrification (BE), as well as load reductions projected to be achieved through Energy Efficiency (EE), Organic EE, Conservation Voltage Optimization (CVO), Demand Response (DR), and the integration of Distributed Generation (DG), Solar Photovoltaics (PV) and Battery Storage.

Project Relationships (if applicable)
This project facilitates the transfer of load from the Washington Street Area Substation to the Cedar Street Area Substation. The actual transfer of the load will be implemented under a separate electric distribution project, the Washington Street to Cedar Street transfer.

3. Funding Detail ($000)

Historic Spend

	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Test Year* (O&M Only)	Forecast 2024
O&M	$0	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	N/A	$0
Capital	$0	$0	$0	$0	N/A	$0

2025-2029 Request:
Total Request by Year:

	2025	2026 (RY1)	2027 (RY2)	2028 (RY3)	2029
O&M	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	$0
Capital (Total)	$0	$12,535	$25,070	$37,605	$77,210
Labor	$0	$2,990	$5,918	$8,595	$17,678
M&S	$0	$3,084	$5,895	$8,561	$17,607
Contract Svcs.	$0	$3,629	$7,074	$10,273	$21,129
Other	$0	$484	$943	$1,370	$2,817
Overheads	$0	$2,348	$5,240	$8,806	$17,979

*The test year runs from 10/1/2023 to 9/30/2024

Central Operations / Substation Operations
2025-2029

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Establish Nevins Street Area Substation	
Project/Program Manager: Partha Roy	**Project/Program Number (Level 1):** 27724606
Status: ☒ **Initiation/Planning** ☐ **In-Progress (Projects Only)** ☐ **On-going (Programs Only)**	
Estimated Start Date: 2026	**Estimated Date In Service:** 2032
2025-2029 Funding Request ($000) **Capital:** $415,000 **O&M:** $0	

Work Description:
This project will establish the Nevins Street Area Substation, a new indoor 27kV area substation that will be arranged in a double syn bus configuration and with an initial build of four 93.3 MVA 138/27kV transformer banks (and capacitors totaling 30 MVAR), with provisions for expansion to five transformer banks. The new Nevins St. Area Substation will be supplied by the 345 kV Brooklyn Clean Energy Hub (BCEH). This project will reduce the load on transmission level transformers, sub-transmission feeders and the Area Substation. The Nevins Street Area Substation will also serve load from Water Street Area Substation (2032) and provide load relief to the Plymouth Street Area Substation in the future.

The area substation shall be designed as an indoor substation. All switchgear sections, battery rooms, test equipment, control room shall be in one control building with the latest Substation reliability enhancements incorporated. The station bus arrangement utilizes two separately non-connected SYN buses to connect the transformers. Each transformer bank shall feed two switchgear sections with five feeders each, for a total of 40.

The major scopes of work remaining to be completed as part of this project include design and construction of the following project phases:

- Property Acquisition (completed)
- Engineering Package Development (underway)
- Site Demolition & Remediation (underway)
- Pour Foundation
- Erect Building Structure
- Complete Building Interiors (Mechanical, Electrical & Plumbing)
- Procure and Install Substation Equipment
- Complete sub-transmission feeder Installation
- Complete substation Terminations and Commissioning

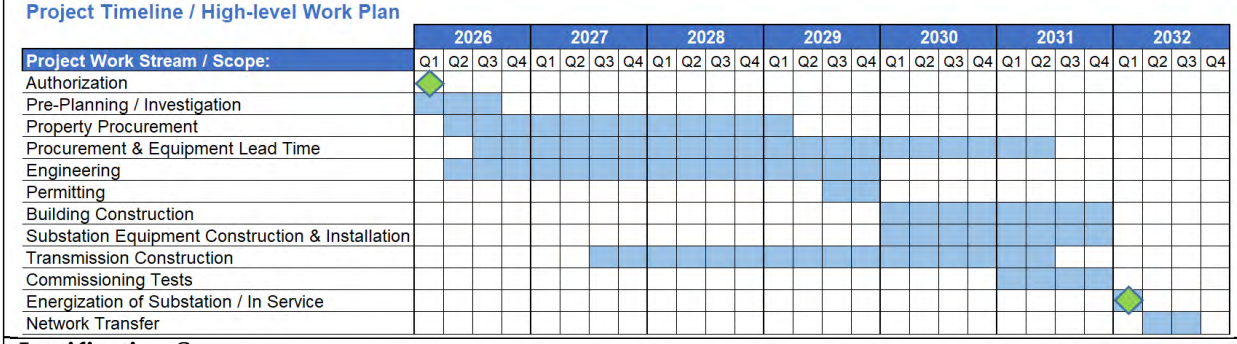
Major or long lead equipment requirements for the project include, but are not limited to:

Major Equipment Type	Number to be Purchased
93.3 MVA 138/27kV Transformers	4
138kV Circuit Switchers	4
138 kV XLPE Cable	20.4 miles
30 MVAR Capacitor Banks	2
27kV Switchgear Sections	4
Manholes	20

Engineering and long lead equipment procurement will begin in early 2026 for this project and construction is expected to begin in 2030. The new Nevins Street Area Substation will be constructed on property already owned by the Company on Nevins Street, between Baltic Street and Butler Street. The in-service date of this project is May 15, 2032.

The estimated timeline to complete the major scopes of work associated with the project is below. This timeline is subject to change at any time, as the Company optimizes the project schedule and incorporates impacts of other projects and system performance.

Project Timeline / High-level Work Plan



Justification Summary:

The Nevins Street Area Substation is required to be established in 2032 to provide load relief to Water Street Area Substation. The new Nevins Street Area Substation is to be supplied by the 345 kV Switching Station, Brooklyn Clean Energy Hub and will be established with four transformers and a 30 MVAR capacitor bank, resulting in a station capability of 358 MW. This new Area Substation will provide added capacity to North Brooklyn for future load growth.

Recently, the Company's latest 2024 forecast confirmed that the Water Street Area Station and its supply transmission transformers and associated 138 kV sub-transmission feeders require load relief in 2032.

Water Street	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Williamsburg	348	362	375	383	389	393	397	401	405	408
Prospect Park	68	69	70	71	72	73	73	74	74	74
Total Load	416	431	445	454	461	466	470	475	479	482
Electrification Adjustment	3	9	11	15	21	27	34	41	49	57
Other Adjustments	-6	-10	-12	-16	-16	-12	-14	-15	-16	-16
Net Load	413	430	444	453	466	481	490	501	512	523
Capability	497									
							overload	4	15	26
138 kV Feeder Capability	532									
138 kV Feeder Loading	78%	81%	83%	85%	88%	90%	92%	94%	96%	98%
									overload	
Farragut X-winding Load	293	310	324	333	346	361	370	381	392	403
Capability	373									
							overload	8	19	30
Farragut X-winding Loading	79%	83%	87%	89%	93%	97%	99%	102%	105%	108%
[TR5 S.E. 300-Hr Rating = 552 Amps]										

Previously, the Water Street Area Substation and supplying 138 kV sub-transmission feeders and the Farragut 345/138 kV transformers were reinforced the with the installation of Vinegar Hill Distribution Switching Station (VHDSS), which provided an additional 120 MW capability. The VHDSS was installed to defer load transfers by providing additional capability to both Water Street and Plymouth Street Area Substations located in North Brooklyn. No additional capacity can be added to the Water Street Area Substation and a load transfer is required to de-load the substation along with its 138 kV supply feeders and Farragut 345/138 kV X-winding transmission transformers. A 140 MW load transfer which will split the Williamsburg Network supplied by Water Street Area Substation will be picked up by Nevins Street in 2032 to provide load relief.

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Water Street (post-transfer)										
Williamsburg	348	362	375	383	389	393	397	261	264	266
Prospect Park	68	69	70	71	72	73	73	74	74	74
Total Load	416	431	445	454	461	466	470	335	338	340
Electrification Adjustment	3	9	11	15	21	27	34	28	33	38
Other Adjustments	-6	-10	-12	-16	-16	-12	-14	-11	-11	-11
Net Load	413	430	444	453	466	481	490	352	360	367
Capability	497									

In addition to the planned load transfer from the Water Street Area Substation, Nevins Street Area Substation may also provide load relief to the Plymouth Street Area substation in the future.

Relationship to Broader Company Plans, Initiatives and the NYS Climate Leadership and Community Protection Act

This project will not directly impact greenhouse gas emissions.

This project strengthens the Con Edison electric system and its ability to serve growing loads in the areas served by these facilities, including service to disadvantaged communities.

By enabling load splits and smaller distribution networks in the Greenwood load area, this program will progressively increase the reliability of the associated networks in both the near and long term.

The program will alleviate issues in the transmission system which limit the load capacity in the Greenwood substation. It will help the Company avoid public safety issues related to network failure, customer outages and significant damage to company equipment. Also, it will protect customers from any issues related to network shutdown.

The operational measures and system improvements implemented with this project would be sufficient in addressing load growth across Company networks in central Brooklyn.

This project is a core investment that enables the Company to continue to provide safe and reliable service, even as the nature of the grid changes. This aligns with Con Edison's strategic objective of providing world-class safety, reliability, and security, while managing the equity challenges of the energy transition.

This project supports the State's achievement of CLCPA and clean energy goals. This aligns with Con Edison's strategic objective to meet economy-wide net-zero GHG emissions in our service territories by 2050.

2. Supplemental Information

Alternatives
An alternative considered was to rely upon Customer Sided Solutions (CSS) such as energy efficiency programs to mitigate any future sub-transmission capacity deficiencies. Energy efficiency programs can provide cost-beneficial solutions across multiple customer segments by accelerating load relief through little-to-no cost energy efficient upgrades and may aid in the deferral of traditional solutions for multiple years. Based on the magnitude of load relief required to address the overload constraints in the Bronx under a limited time frame, it has been assessed that an energy efficiency program is not a viable option. There is no known contingency plan other than to pursue the identified traditional solution should this alternative be pursued and prove unable to meet the projected deficits.

Risk of No Action
The capacity of the Greenwood Area Substation is predicted to be exceeded by the early 2030's given forecasted load growth. Many of Con Edison's Brooklyn and Queens area substations are near full capacity and do not offer the feasibility of load transfer. In the event the transmission feeders overload, load shedding may be required during peak conditions which would cause thousands of customers to encounter service outages.

Without pursuing the project, the Company networks will encounter the potential inability of maintaining reliable system power flow controls, system reliability and resiliency concerns and/or possible customer outages for an extended period during peak load conditions.

Non-Financial Benefits
This project will provide the necessary reliability and resiliency in an area of New York City that serves many critical loads (e.g., airports, transportation hubs, and hospitals) in a densely populated area where many buildings have elevators and various equipment loads. Relief of overloaded Greenwood substation will ensure continued reliable service to the Bay Ridge and Park Slope load areas and will allow the station to maintain the area substation N-1 reliability design criteria for long-term projected load growth in the Bronx.

The increased capacity brought on by Nevins can minimize customer impact during an area station event. Resiliency options are not feasible in this load pocket without the use of rolling blackouts and mobile stations which require a time-intensive set-up. By introducing new area station capacity and

splitting current networks into smaller load areas, the Company will be able to handle loss of station capacity during emergencies and its impact on customers.

Meeting New York's Climate Leadership and Community Protection Act (CLCPA) goals will ultimately require the Company to build system capacity for an anticipated increase in load growth. With electrification of the City, as we move away from a carbon economy, we will require capacity in the affected networks to accommodate unprecedented load growth. Rapid load growth has the potential to leave the Company in a difficult position to address all the relief and reliability challenges in the near future.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)
N/A

2. Major financial benefits
N/A

3. Basis for estimate
This estimate is based on an order of magnitude estimate of project costs based on a conceptual design and historical costs for similar scopes of work. High-level estimates of total costs, by primary spend category, are shown below, including escalation, overheads, and contingency.

	Estimated Direct Costs	*Esc., OH, & Other Loading*[1]	*Estimated Total*	*% of Total*
01-Labor	$ 71,219,474	$148,816,223	$220,035,697	27.7%
02-MSH	$ 69,548,257	$ 85,729,915	$155,278,172	19.6%
03-Cont Svcs	$165,070,446	$203,477,066	$368,547,512	46.4%
09-Other	$ 22,367,618	$ 27,571,848	$ 49,939,466	6.3%
Total	**$328,205,795**	**$465,595,052**	**$793,800,847**	

[1]Includes: Escalation (46%), CE OH (0%), A&S (2.5%), PT&P (39.35%), AFDC (14.73%), and Contingency (30%)

Project Risks and Mitigation Plan

Risk 1
Delays due resource/support coordination. There are a large number of projects to expand the electric distribution system that may strain existing resources.

Mitigation Plan 1:
Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts. Expand hiring and increase the number of employees over the next few years to be able to handle the increased flow of work.

Risk 2
Material Availability Issues

Mitigation Plan 2:
Engineering will work with Supply Chain to establish a cohesive plan that aligns with vendor lead times. Stay engaged with vendors to ensure lead times are maintained, and adjust the plan as needed if shortages are encountered.

Technical Evaluation / Analysis
N/A

Project Relationships (if applicable)
N/A

3. Funding Detail ($000)

Historic Spend

	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Test Year* (O&M Only)	Forecast 2024
O&M	$0	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	N/A	$0
Capital	$0	$0	$0	$0	N/A	$0

2025-2029 Request:
Total Request by Year:

	2025	2026 (RY1)	2027 (RY2)	2028 (RY3)	2029
O&M	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	$0
Capital (Total)	$0	$15,000	$75,000	$100,000	$225,000
Labor	$0	3,631	17,930	23,007	24,704
M&S	$0	3,653	18,038	22,915	67,569
Contract Svcs.	$0	4,383	21,646	27,498	81,082
Other	$0	584	2,886	3,666	10,837
Overheads	$0	2,749	14,500	22,914	40,808

*The test year runs from 10/1/2023 to 9/30/2024

Central Operations / Substation Operations
2025-2029

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Grasslands Install Fourth Transformer with Its 138kV Supply Feeder	
Project/Program Manager: Partha Roy	**Project/Program Number (Level 1):** 28016997
Status: ☒ **Initiation/Planning** ☐ **In-Progress (Projects Only)** ☐ **On-going (Programs Only)**	
Estimated Start Date: 2027	**Estimated Date In Service: 2033**
2025-2029 Funding Request ($000) **Capital:** $40,000 **O&M:** $0	

Work Description:

This project is designed to increase the capability at the Grasslands Area Substation to accept White Plains Area Substation load transfer of approximately 52 MW and Elmsford No.2 load transfer of approximately 32 MW in 2033. This project will establish a fourth 138/13kV transformer bank at Grasslands Substation, to be supplied by a new 138kV feeder approximately 1.5 miles from Eastview to Grasslands.

Major scopes of work to be completed under this project include:

- At Eastview, install one 138kV circuit switcher support structure & associated foundation.
- At Eastview, install one 138kV pothead support structure & associated foundation.
- Relocate existing Server Farm 150kW Emergency Generator.
- Install one 138kV circuit switcher support structure & associated foundation.
- Install one 138kV pothead support structure & associated foundation.
- Install new 138kV feeder approximately 1.5 miles, from Eastview to Grasslands
- Install and connect new 138/13kV Transformer 4
- Connect Transformer 4 to existing 13kV Switchgear Section 4

Major or long lead equipment requirements for the project include, but are not limited to:

Major Equipment Type	Number to be Purchased
138/13 kV 65 MVA Transformer	1 each
13kV 3Ø Segregated Bus	100 feet
138kV Surge Arresters	1 each
138kV Circuit Switcher & Interrupter	2 each
138kV 3-1Ø Ground Switch	1 each
138kV 3Ø Ground Switch	1 each
138kV Pothead Set	2 each

Engineering and long lead equipment procurement will begin in 2028 for this project, and construction is expected to begin in 2031 and be completed in 2033. The estimated timeline to complete the major

scopes of work associated with the project is below. This timeline is subject to change at any time, as the Company optimizes the project schedule and incorporates impacts of other projects and system performance.

Project Timeline / High-level Work Plan	2028				2029				2030				2031				2032				2033			
Project Work Stream / Scope:	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Authorization				◆																				
Pre-Planning / Conceptual Scope and Estimate																								
Appropriations																								
Procurement: Land, Equipment, and Contracting																								
Engineering																								
Permitting																								
Site Preparation (including demolition)																								
Construction																								
Testing and Commissioning																								
Energization / In-Service																						◆		

Justification Summary:

This project is part of the solution being implemented to alleviate forecasted load constraints on the Eastview Elmsford load pocket which is comprised of three Area Substations – Elmsford No.2, White Plains, and Harrison. Based on forecasted load growth for the Eastview – Elmsford load pocket, the 138 kV sub-transmission feeders will surpass their capability by 2033. Additionally, White Plains Area Substation will be projected to utilize its 1-hour capability in 2033 and exceed it in 2036.

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Elmsford No. 2	160	165	169	172	174	175	176	177	178	179	180	181	182	183	183	184	185	185	186	187
Electrification Adjustment	1	3	5	8	10	13	16	19	22	25	27	29	32	34	36	38	40	42	43	44
Other Adjustments	-6	-8	-10	-13	-13	-12	-13	-14	-14	-15	-16	-16	-17	-17	-18	-18	-19	-20	-20	-21
Net Load	155	160	164	167	171	176	179	182	186	189	191	194	197	200	201	204	206	207	209	210
Capability	239																			
White Plains	210	220	229	236	242	244	247	249	251	253	255	257	259	261	263	264	266	267	269	270
Electrification Adjustment	3	5	8	12	18	24	30	36	42	47	52	56	60	64	67	70	72	73	74	74
Other Adjustments	-9	-15	-19	-21	-23	-22	-23	-24	-25	-26	-27	-28	-29	-30	-31	-32	-34	-35	-36	-37
Net Load	204	210	218	227	237	246	254	261	268	274	280	285	290	295	299	302	304	305	307	307
Capability	265																			
1-Hour Capability	281																			
Harrison	199	205	211	215	218	219	220	222	223	224	225	226	227	228	229	230	231	232	233	234
Electrification Adjustment	1	5	5	8	10	13	16	19	21	24	26	28	30	32	33	34	35	36	37	38
Other Adjustments	-5	-7	-10	-13	-14	-14	-15	-16	-16	-18	-18	-19	-20	-21	-21	-21	-22	-23	-24	-25
Net Load	195	203	206	210	214	218	221	225	228	230	233	235	237	239	241	243	244	245	246	247
Capability	243																			
1-Hour Capability	258																			
Eastview-Elmsford Load	554	573	588	604	622	640	654	668	682	693	704	714	724	734	741	749	754	757	762	764
Feeder Peak Diversity	1	0	2	4	6	10	10	11	11	14	15	16	16	16	18	17	19	21	19	20
Net Load	555	573	590	608	628	650	664	679	693	707	719	730	740	750	759	766	773	778	781	784
Post-Contingency Capability	685																			
Deficit									8	22	34	45	55	65	74	81	88	93	96	99
138 kV Feeder Loading	81%	84%	86%	89%	92%	95%	97%	99%	101%	103%	105%	107%	108%	109%	111%	112%	113%	114%	114%	114%
	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**
Grasslands	105	113	122	127	131	133	135	137	139	141	142	144	145	147	148	149	151	152	153	154
Electrification Adjustment	2	4	5	7	8	10	11	13	14	16	17	18	20	21	22	23	24	25	26	26
Other Adjustments	-4	-5	-7	-11	-15	-20	-23	-24	-25	-27	-28	-29	-31	-32	-33	-34	-35	-36	-37	-38
Net Load	103	112	120	123	124	123	123	126	128	130	131	133	134	136	137	138	140	141	142	142
Capability	165																			

Transferring approximately 52 MW of load from White Plains and approximately 32 MW of load from Elmsford No.2 to Grasslands alleviates the forecasted constraint on the 138 kV sub-transmission feeders and addresses future constraint at White Plains Area Substation

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Elmsford No. 2	160	165	169	172	174	175	176	177	146	147	148	148	149	150	150	151	152	152	153	153
Electrification Adjustment	1	3	5	8	10	13	16	19	18	21	22	24	26	28	30	31	33	34	35	36
Other Adjustments	-6	-8	-10	-13	-13	-12	-13	-14	-11	-13	-13	-13	-14	-14	-15	-15	-16	-16	-16	-17
Net Load	155	160	164	167	171	176	179	182	153	155	157	159	161	164	171	167	169	170	172	172
Capability	239																			
White Plains	210	220	229	236	242	244	247	249	199	201	202	204	205	207	209	209	211	212	213	214
Electrification Adjustment	3	5	8	12	18	24	30	36	33	37	41	44	48	51	53	55	57	58	59	59
Other Adjustments	-9	-15	-19	-21	-23	-22	-23	-24	-20	-20	-21	-22	-23	-24	-24	-25	-27	-28	-29	-30
Net Load	204	210	218	227	237	246	254	261	212	218	222	226	230	234	238	239	241	242	243	243
Capability	265																			
1-Hour Capability	281																			
Harrison	199	205	211	215	218	219	220	222	223	224	225	226	227	228	229	230	231	232	233	234
Electrification Adjustment	1	5	5	8	10	13	16	19	21	24	26	28	30	32	33	34	35	36	37	38
Other Adjustments	-5	-7	-10	-13	-14	-14	-15	-16	-16	-18	-18	-19	-20	-21	-21	-21	-22	-23	-24	-25
	195	203	206	210	214	218	221	225	228	230	233	235	237	239	241	243	244	245	246	247
Capability	243																			
1-Hour Capability	258																			
Eastview-Elmsford Load	554	573	588	604	622	640	654	668	593	603	612	620	628	637	650	649	654	657	661	662
Feeder Peak Diversity	1	0	2	4	6	10	10	11	11	14	15	16	16	16	18	17	19	21	19	20
Net Load	555	573	590	608	628	650	664	679	604	617	627	636	644	653	668	666	673	678	680	682
Post-Contingency Capability	685																			
138 kV Feeder Loading	81%	84%	86%	88%	91%	93%	95%	98%	87%	88%	89%	91%	92%	93%	95%	95%	95%	96%	96%	97%

Although transferring this load from the White Plains and Elmsford No.2 Area Substations to the Grasslands relieves the forecasted load constraint on the Eastview – Elmsford 138 kV sub-transmission feeders and White Plains Area Substation in 2036, it causes a load constraint at the Grasslands Area Substation.

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Grasslands	105	113	122	127	131	133	135	137	223	225	227	230	232	234	235	237	239	240	242	244
Electrification Adjustment	2	4	5	7	8	10	11	13	27	30	33	35	38	40	42	45	46	48	49	49
Other Adjustments	-4	-5	-7	-11	-15	-20	-23	-24	-33	-35	-37	-38	-40	-41	-43	-44	-45	-47	-48	-49
Net Load	103	112	120	123	124	123	123	126	217	220	223	227	230	233	234	238	240	241	243	244
Capability	165								247											

This project is needed to increase the capability at the Grasslands Area Substation so that the White Plains load transfer can be added to Grasslands without causing a constraint on the area substation. The additional equipment being installed by this project increases the capability of the Grasslands Area Substation from 165 MW to 247 MW in 2033.

Relationship to Broader Company Plans, Initiatives and the NYS Climate Leadership and Community Protection Act

This project will not directly impact greenhouse gas emissions.

This project will strengthen the overall transmission system and networks served by including any DACs in the area or downstream from this project.

Meeting New York's CLCPA goals will ultimately require the Company to build system capacity for an anticipated increase in load growth. With electrification of the City, as we move away from a carbon economy, we will require capacity in the affected networks to accommodate unprecedented load growth. Rapid load growth has the potential to leave the Company in a difficult position to address all the relief and reliability challenges in the near future.

This project is a core investment that enables the Company to continue to provide safe and reliable service, even as the nature of the grid changes. This aligns with Con Edison's strategic objective of providing world-class safety, reliability, and security, while managing the equity challenges of the energy transition.

2. Supplemental Information

Alternatives

Alternative 1

No Load Transfer – An alternative solution to this project which was considered was the installation of a third transformer at White Plains Area Station itself. While this would eliminate the need for a load transfer, the station was not originally designed with the available future space for an additional transformer. To achieve this, the existing station, including security fence and grounding grid would have to be expanded, adding significant costs.

Risk of No Action

If no action is taken to alleviate forecasted capability exceedances at the due to load growth, there is a high risk of overloading the substation equipment during peak load conditions. Exceeding the rated capacity of the substation could result in load shedding if contingencies occur during peak loading conditions resulting in customer outages, increasing the risk of equipment failure, and adversely impacting the community served, as well as encountering the potential inability of maintaining reliable system power flow controls, system reliability and resiliency concerns.

Non-Financial Benefits

This project will facilitate the necessary load relief for overloaded feeders and equipment, which will ensure the continuity of reliable service in the areas served by the

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)
N/A

2. Major financial benefits
N/A

3. Basis for estimate

No cost estimate has been completed for this project at this point; however, this project is expected to involve similar work scope as the Parkchester No. 1 5th Transformer 9S & Supply Feeder 38X05 project and the estimated cost of that project is being used as an initial proxy. The proxy estimate is based on

an order of magnitude estimate of project costs based on a conceptual design and historical costs for similar scopes of work. High-level estimates of total costs, by primary spend category, are shown below, including escalation, overheads, and contingency.

	Estimated Direct Costs	*Esc., OH, & Other Loading*[1]	*Estimated Total*	*% of Total*
01-Labor	$ 8,622,178	$ 12,692,628	$ 21,314,806	16.8%
02-MSH	$ 16,731,957	$ 14,501,260	$ 31,233,217	24.6%
03-Cont Svcs	$ 35,127,497	$ 30,444,317	$ 65,571,814	51.7%
09-Other	$ 4,661,400	$ 4,039,944	$ 8,701,344	6.9%
Total	**$ 65,143,032**	**$ 61,678,149**	**$126,821,181**	

[1]Includes: Escalation (11.00%), CE OH (13.25%), A&S (2.53%), PT&P (39.35%), AFDC (6.62%), and Contingency (30%)

Project Risks and Mitigation Plan

Risk 1:
Delays due to resource/support coordination

Mitigation Plan 1:
Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Risk 2:
Material Availability Issues

Mitigation Plan 2:
Engineering will work with Supply Chain to establish a cohesive plan that aligns with vendor lead times. Stay engaged with vendors to ensure lead times are maintained, and adjust the plan as needed if shortages are encountered.

Technical Evaluation / Analysis

The need for this project is based on the 2025-2034 Area Substation and Sub-transmission Feeder Ten-Year Load Relief Program (LRP). The LRP reflects increased forecasted demand from transportation (EVs) and building electrification (BE), as well as load reductions projected to be achieved through Energy Efficiency (EE), Organic EE, Conservation Voltage Optimization (CVO), Demand Response (DR), and the integration of Distributed Generation (DG), Solar Photovoltaics (PV) and Battery Storage.

Project Relationships (if applicable)

This project facilitates the transfer of load from the White Plains and Elmsford No. 2 area substations to the Grasslands Area Substation to relieve forecasted constraints. The actual transfers of load will be implemented under a separate electric distribution project.

3. Funding Detail ($000)

Historic Spend

	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Test Year* (O&M Only)	Forecast 2024
O&M	$0	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	N/A	$0
Capital	$0	$0	$0	$0	N/A	$0

2025-2029 Request:
Total Request by Year:

	2025	2026 (RY1)	2027 (RY2)	2028 (RY3)	2029
O&M	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	$0
Capital (Total)	$0	$0	$3,000	$7,000	$30,000
Labor	$0		$450	$1,064	$7,330
M&S	$0		$1,000	$2,340	$8,190
Contract Svcs.	$0		$950	$2,000	$8,000
Other	$0		$143	$350	$298
Overheads	$0		$457	$1,246	$6,182

*The test year runs from 10/1/2023 to 9/30/2024

Central Operations / SSO

2025-2029

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Establish Hillside Area Substation	
Project/Program Manager: Partha Roy	**Project/Program Number (Level 1):** 27724605
Status: ☒ **Initiation/Planning** ☐ **In-Progress (Projects Only)** ☐ **On-going (Programs Only)**	
Estimated Start Date: 2026	**Estimated Date In Service:** 2033
2025-2029 Funding Request ($000) **Capital:** $465,000 **O&M:**	

Work Description:
This project will establish the Hillside Area Station, a new indoor 27kV area substation that will be arranged in a double syn bus configuration and with an initial build of four (4) 93.3 MVA 138/27kV transformer banks (and capacitors totaling 30 MVAR), with provisions for expansion to five (5) transformer banks. The station will be supplied from the Eastern Queens Transmission Substation, add resiliency to the network, and provide additional sub-transmission capacity of 358MW to mitigate design capability deficiencies in the Jamaica load area to meet projected load growth.

The Hillside Area Station will be necessary for providing load relief to the Corona No. 1 Area Station by transferring approximately 150MW out of the existing Flushing Network, and other radial loads, and establishing the new Bayside Network in 2033. Additionally in the future, Hillside will provide load relief to Corona No. 2 Area Station by transferring 100 MW out of existing Rego Park Network, establishing the new Cunningham Network.

Major scopes of work to be completed under this project include:

- Property procurement/land acquisition in in the North-East area of Queens, NY
- Engineering Package Development
- Site Demolition and Remediation
- Installation of Foundation
- Installation of Structural Buildings
  - Control room
  - Relay houses
  - Battery rooms
- Substation Equipment Procurement and Installation
- Mechanical, Electrical, Plumbing and Fire Protection
- Sub-transmission Feeder Installation
- Substation Terminations and Commissioning

Major or long lead equipment requirements for the project include, but are not limited to:

Major Equipment Type	Number to be Purchased
93.3 MVA 138/27kV Transformers	4
138kV Circuit Switchers	4
20 MVAR Capacitor Banks	2
27kV Switchgear Sections	4

Engineering and long lead equipment procurement will begin in 2026 for this project and substation construction is expected to begin in 2030 and to be completed by the end of 2032. This timeline is subject to change at any time, as the Company optimizes the project schedule and incorporates impacts of other projects and system performance.

Justification Summary:

The establishment of Hillside Area Substation will provide load relief to Corona No.1 Area Substation and eventually Corona No.2 Area Substation.

With the Company's 2024 forecast, Corona No.1 Area Substation is projected to be overloaded in 2032.

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Corona No. 1																				
Flushing	376	389	408	430	434	437	439	441	443	445	447	449	451	453	454	456	458	459	460	462
Radial	25	25	25	26	26	27	27	27	28	28	28	29	29	29	29	30	30	30	31	31
Total Load	401	414	433	456	460	464	466	468	471	473	475	478	480	482	483	486	488	489	491	493
Electrification Adjustment	5	9	16	21	29	38	47	57	68	80	93	105	118	131	144	158	171	185	198	212
Other Adjustments	-8	-10	-13	-15	-15	-11	-11	-11	-12	-13	-13	-13	-14	-15	-15	-16	-17	-18	-18	-20
Net Load	398	413	436	462	474	491	502	514	527	540	555	570	584	598	612	628	642	656	671	685
Capability	511																			
deficits								3	16	29	44	59	73	87	101	117	131	145	160	174

The load growth in Corona No.1 Area Substation requires a load transfer as early as 2032, however the earliest date Hillside Area Substation can be constructed and established is 2033. The Company is currently evaluating measures such as Battery Energy Storage System to address the 3 MW need in 2032 which have not yet been determined. A planned 150 MW load transfer part of the Flushing Network to the new Hillside Area Substation establishing the Bayside Network in 2033 and Corona No.1 Radial load transfer will alleviate overloads at the area substation. Total Flushing network and radial load transferred from 2033 to 2044 can be seen below:

Corona No. 1		2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Flushing Network and Radial	Base Network MW Transferred	150	151	151	152	153	153	154	154	155	155	156	156
	Radial Transferred	28	28	28	29	29	29	29	30	30	30	31	31
	Electrification Transferred	23	27	31	36	40	44	49	53	58	63	67	72
	Other Adjustments Transferred	-4	-4	-4	-5	-5	-5	-5	-5	-6	-6	-6	-7
	Total Flushing and Radial Load Transferred	**197**	**202**	**206**	**212**	**217**	**221**	**227**	**232**	**237**	**242**	**248**	**252**

The resulting load transfer will leave approximately 78 MW headroom at Corona No.1 in 2044 as seen below:

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Corona No. 1																				
Flushing	376	389	408	430	434	437	439	441	293	294	296	297	298	300	300	302	303	304	304	306
Radial	25	25	25	26	26	27	27	27	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	401	414	433	456	460	464	466	468	293	294	296	297	298	300	300	302	303	304	304	306
Electrification Adjustment	5	9	16	21	29	38	47	57	45	53	62	69	78	87	95	105	113	122	131	140
Other Adjustments	-8	-10	-13	-15	-15	-11	-11	-11	-8	-9	-9	-8	-9	-10	-10	-11	-11	-12	-12	-13
Net Load	398	413	436	462	474	491	502	514	330	338	349	358	367	377	385	396	405	414	423	433
Capability	511							TBD												

Adjacent Area Substations in Queens are unable to accept a load transfer from Corona No.1 to provide load relief, Glendale has sub-transmission feeder constraints 2026 to 2034, and Corona No.2 also requires limiting bus and disconnect switch upgrades in 2032 and a load transfer to Hillside Area Substation in 2039:

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Corona No. 2																				
Rego Park	214	220	226	231	234	236	237	239	240	242	243	245	246	247	249	250	251	252	253	254
Jackson Heights	191	193	195	195	195	195	196	196	197	197	197	198	198	198	198	199	199	199	199	200
Total Load	405	413	421	426	429	431	433	435	437	439	440	443	444	445	447	449	450	451	452	454
Electrification Adjustment	3	7	12	18	23	31	37	44	51	59	66	74	81	87	95	101	107	113	118	124
Other Adjustments	-6	-8	-10	-13	-12	-9	-8	-9	-9	-10	-9	-11	-11	-11	-13	-12	-13	-14	-15	-16
Net Load	402	412	423	431	440	453	462	470	479	488	497	506	514	521	529	538	544	550	555	562
Capability	463						525													
deficits															4	13	19	25	30	37

Hillside Area Substation will also provide benefits of de-loading Corona No.2 in 2039, with a planned 100 MW load transfer splitting Rego Park and creating the new Cunningham network to be supplied by Hillside:

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Corona No. 2																				
Rego Park	214	220	226	231	234	236	237	239	240	242	243	245	246	247	149	150	150	151	151	152
Jackson Heights	191	193	195	195	195	195	196	196	197	197	197	198	198	198	198	199	199	199	199	200
Total Load	405	413	421	426	429	431	433	435	437	439	440	443	444	445	347	349	349	350	350	352
Electrification Adjustment	3	7	12	18	23	31	37	44	51	59	66	74	81	87	73	78	83	88	92	97
Other Adjustments	-6	-8	-10	-13	-12	-9	-8	-9	-9	-10	-9	-11	-11	-11	-9	-9	-9	-10	-11	-11
Net Load	402	412	423	431	440	453	462	470	479	488	497	506	514	521	411	418	423	428	431	438
Capability	463							525												
	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**
Hillside																				
Cunningham															100	100	101	101	102	102
Bayside									150	151	151	152	153	153	154	154	155	155	156	156
Radial									28	28	28	29	29	29	29	30	30	30	31	31
Total Load									178	179	179	181	182	182	283	284	286	286	289	289
Electrification Adjustment									23	27	31	36	40	44	71	76	82	88	93	99
Other Adjustments									-4	-4	-4	-5	-5	-5	-9	-8	-10	-10	-10	-12
Net Load									197	202	206	212	217	221	345	352	358	364	372	376
Capability									358									474		

The establishment of the Hillside Area Substation will provide load relief to Corona No.1 and No.2 Area Substations as Queens Area Substations are at capacity and create headroom for load growth in Corona No.1 and No.2.

Relationship to Broader Company Plans, Initiatives and the NYS Climate Leadership and Community Protection Act

This project is a core investment that enables the Company to continue to provide safe and reliable service, even as the nature of the grid changes. This aligns with Con Edison's strategic objective of providing world-class safety, reliability, and security, while managing the equity challenges of the energy transition.

This project supports the State's achievement of CLCPA and clean energy goals. This aligns with Con Edison's strategic objective to meet economy-wide net-zero GHG emissions in our service territories by 2050.

2. Supplemental Information

Alternatives

Alternative 1: Other solutions considered include reconfiguring networks to leverage available capacity in the North Queens substation and in nearby Queens load pockets. However, this station is geographically located too far away from the load area, resulting in lengthy feeder runs and reduced reliability. There are natural boundaries and existing municipal infrastructure along potential feeder routes that are difficult and geographically challenging in extending distribution feeders, reducing reliability in the electric system. Additionally, the North Queens substation does not have adequate capacity to address the load relief required at the Corona No. 1 substation. There are no other stations in the geographic area that have available capacity to provide the necessary load relief for this project.

Risk of No Action

Risk 1

An overload on the transmission feeders supplying Corona No. 1 Area Substation is predicted to occur. Many of the Company's Queens substations are near full capacity and do not offer the feasibility of load transfer. In the event the transmission feeders become overloaded, load shedding may be required during peak conditions with service dropped to thousands of customers.

Risk 2

If this project is not pursued, the NRI of the networks served by Corona No. 1 Area Substation will be negatively impacted as continued growth without the ability to either split the network or increase feeders would result in an increasing NRI.

Non-Financial Benefits

Alleviating projected load constraints at Corona No. 1 Area Substation will improve reliability and resiliency in an area of New York City that serves many critical loads in a densely populated area where many buildings have elevators. As such, addressing these load constraints will allow the station to maintain the area substation N-1 reliability design criteria for long term projected load growth in Queens.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)

N/A

2. Major financial benefits

N/A

3. Basis for estimate

The estimated cost has been based on an order of magnitude estimate based on previous projects with similar scope to this project costs. High-level estimates of the total costs, by primary spend category, are shown below, including escalation, overheads, and contingency.

	Estimated Direct Costs	*Esc., OH, & Other Loading*[1]	*Estimated Total*	*% of Total*
01-Labor	$ 54,985,300	$ 83,752,057	$138,737,357	13.5%
02-MSH	$120,394,060	$ 99,129,763	$219,523,823	21.4%
03-Cont Svcs	$326,404,229	$268,753,907	$595,158,136	58.0%
09-Other	$ 39,897,000	$ 72,707,396	$ 72,747,293	7.1%
Total	**$541,680,589**	**$524,343,123**	**$1,026,166,609**	

[1]Includes: Escalation (16%), CE OH (0%), A&S (2.53%), PT&P (39.35%), AFDC (17.93%), and Contingency (30%)

Project Risks and Mitigation Plan

Risk 1:

Delays due resource/support coordination. There are a large number of projects to expand the electric distribution system that may strain existing resources.

Mitigation Plan 1:

Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts. Expand hiring and increase the number of employees over the next few years to be able to handle the increased flow of work.

Risk 2:
Material Availability Issues

Mitigation Plan 2:
Engineering will work with Supply Chain to establish a cohesive plan that aligns with vendor lead times. Stay engaged with vendors to ensure lead times are maintained, and adjust the plan as needed if shortages are encountered.

Technical Evaluation / Analysis
N/A

Project Relationships (if applicable)
This project facilitates the Corona No. 1 to Hillside Load Transfer project necessary to provide load relief at Corona No. 1 area substation.

3. Funding Detail ($000)

Historic Spend

	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Test Year* (O&M Only)	Forecast 2024
O&M	$0	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	$0	$0
Capital	$0	$0	$0	$0	$0	$0

2025-2029 Request:
Total Request by Year:

	2025	2026 (RY1)	2027 (RY2)	2028 (RY3)	2029
O&M	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	$0
Capital (Total)	$0	$15,000	$40,000	$110,000	$300,000
Labor	$0	$916	$2,386	$6,509	$17,697
M&S	$0	$6,780	$17,662	$48,187	$131,000
Contract Svcs.	$0	$4,800	$12,504	$34,114	$92,743
Other	$0	$630	$1,641	$4,477	$12,172
Overheads	$0	$1,874	$5,807	$16,713	$46,388

*The test year runs from 10/1/2023 to 9/30/2024

Central Operations / Substation Operations

2025-2029

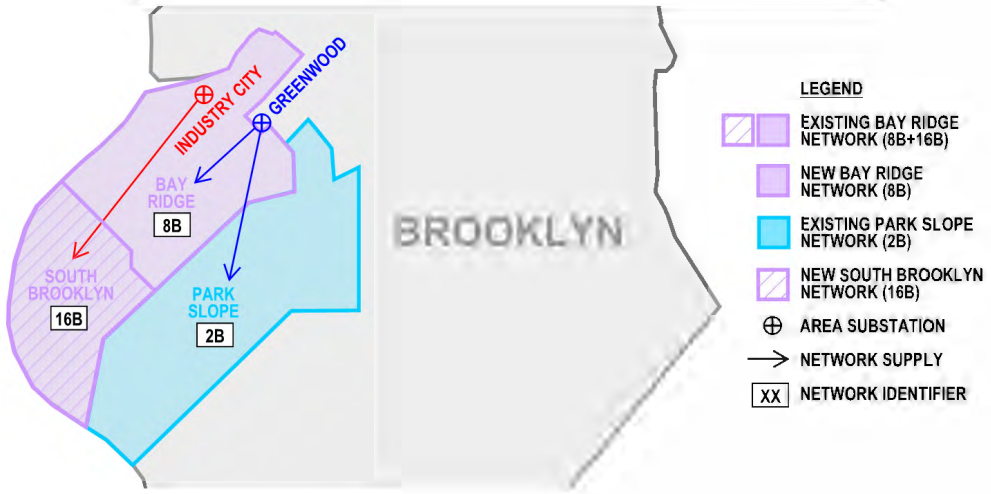
1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Brooklyn Expansion: Sunset Park 345 kV S/S and Industry City 27kV Area Substation	
Project/Program Manager:	**Project/Program Number (Level 1):** 27809975
Status: ☒ **Initiation/Planning** ☐ **In-Progress (Projects Only)** ☐ **On-going (Programs Only)**	
Estimated Start Date: 2026	**Estimated Date In Service:** 2034
2025-2029 Funding Request ($000) **Capital: $ 560,000** **O&M:** $0	

Work Description:

The Brooklyn Expansion project is a three-part project that will address a reliability need in the Greenwood 138kV Transmission Load Area (TLA) and provide load relief to the Greenwood 27kV Distribution Area Substation. The overall project will consist of three parts: 1. Building a new 345kV transmission substation, the Sunset Park 345kV Transmission Substation ("Sunset Park"), which will supply the new Industry City 27kV Distribution Area Substation; 2. Building the new Industry City 27kV Distribution Area Substation ("Industry City"); and 3. Transferring approximately 80 MW from the Bay Ridge Network to the new Industry City 27kV Distribution Area Substation, thereby creating the new South Brooklyn Network ("South Brooklyn"). Both substations will be co-located on a vacant parcel of Company-owned land at 29th Street and 3rd Avenue in Brooklyn.

Greenwood Substation - Bay Ridge Network Cutover Concept



Sunset Park will be designed as an indoor 345kV Gas Insulated Switchgear Transmission Substation,

arranged in a double ring bus configuration with provisions for future points of interconnection. The initial construction will include four (4) 345kV connections (expandable to 5) to supply Industry City. To connect to the Con Edison Transmission System, the Company will bifurcate existing 345kV Feeders 25 and 26, between Goethals Substation and Gowanus Substation, creating four (4) new 345kV connections. In the future, with additional expansion, Sunset Park will be capable of supplying 345kV connections to expand the Eastern Queens Transmission Substation as well as offer Points of Interconnection (POI) for renewable resources such as Off-Shore Wind (OSW).

The Industry Park 27 kV Distribution Area Substation will be designed as an indoor substation with all switchgear sections, battery rooms, test equipment, control room in one control building with the latest substation reliability enhancements incorporated. The station bus arrangement will use two (2) separate, non-connected SYN buses to connect the transformers. The initial construction will include four (4) transformer banks (expandable to 5). Each transformer bank will feed two (2) switchgear sections with five (5) feeders each, for a total of forty (40).

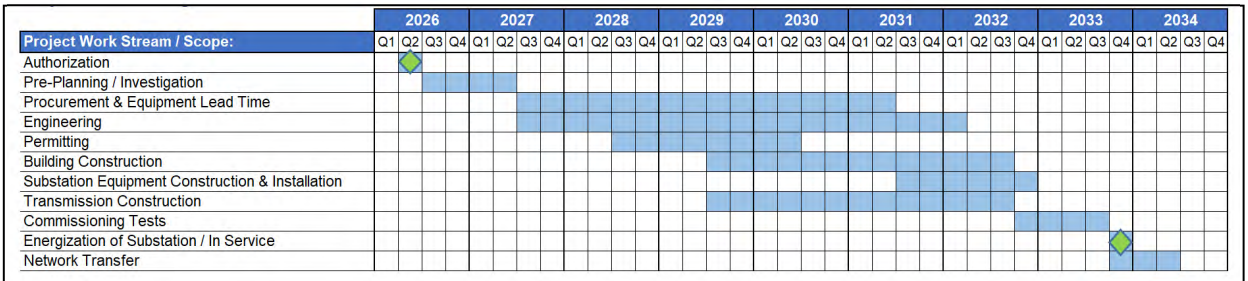
The major scopes of work to be completed to establish the Brooklyn Expansion project include:

- Property Acquisition (completed)
- Engineering Package Development
- Site Demolition & Remediation
- Pouring of Foundation
- Erection of Building Structure
- Completion of Building Interiors (Mechanical, Electrical & Plumbing)
- Procurement and Installation of Substation Equipment
- Completion of Sub-Transmission Feeder Installations
- Completion of Substation Terminations and Commissioning

Major equipment requirements for the project include, but are not limited to:

Major Equipment Type	Number to be Purchased
345kV Gas-Insulated Switchgear Breaker Sections	14
345kV Gas-Insulated switchgear	1
345/138/13kV 300MVA Auto-Transformer	4
345kV Circuit Switcher & Interrupter	4
138/27kV 93MVA Transformer	4
138kV Circuit Switcher & Interrupter	4
27kV Switchgear Sections	4
L&P Transformer	2

Engineering and long lead equipment procurement are expected to begin in 2026 for this project and station construction is expected to begin in early 2029. The estimated timeline to complete construction of the Sunset Park & Industry City Substations is below. This timeline is subject to change at any time, as the Company optimizes the project schedule and incorporates impacts of other projects and system performance. The in-service date for the Sunset Park substation is April 2034, the in-service dates for the Industry City and the South Brooklyn Networks are May 2034.



Justification Summary:

The Greenwood 27 kV Distribution Area Substation along with Bensonhurst No. 1 & No. 2 27 kV Distribution Area Substations are located within the Greenwood 138 kV TLA. Based on the latest load forecast numbers, additional deficits of 40MW in 2030 and 80MW in 2031 were identified in the Greenwood 138 kV TLA. These deficits are driven by immediate post contingency long-term emergency (LTE) limitations and can increase, depending on how the system is aligned at the time. To address the Greenwood 138 kV TLA needs, a load transfer from Bensonhurst No.2 splitting the Flatbush network and sending it to Gateway Park in 2030 will be planned as described in "Flatbush Network Split – Bensonhurst No.2 to Gateway Park".

The Greenwood 27kV Distribution Area Substation will require load relief beginning as soon as 2028, as seen in the table below.

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Greenwood (pre-transfer)										
Bay Ridge	250	259	267	272	276	278	281	283	286	288
Park Slope	214	216	217	217	218	218	219	220	220	221
Radial	23	24	24	24	24	25	25	25	25	25
Total Load	487	499	508	513	518	521	525	528	531	534
Electrification Adjustment	9	14	19	24	29	35	42	50	56	63
Other Adjustments	-8	-13	-16	-20	-20	-15	-17	-20	-20	-21
Net Load	488	500	511	517	527	541	550	558	567	576
Capability	511	511	511	511	511	511	511	511	511	511

Due to accelerated load growth, a number of load relief measures will be implemented to address the issue until the main solution can be constructed and executed - a load transfer to the new Industry City Area substation. To address Greenwood 27 kV Distribution Area Substation overloads, installation of additional transformer cooling will occur in 2028 for transformers no. 1, 2, 3 and 5 to achieve a 300-hr rating of 136 MVA, and through the emergent load relief program transformer 4 will be replaced and equipped with additional cooling to achieve a 300-hr rating of 136 MVA, all of which will add 26 MW of capability for a total of 537 MW. This increased station capability will address demand from 2028 to 2029. In 2030 the Company will transfer approximately 25 MW of radial load from Greenwood to Bensonhurst No. 2, followed by approximately 6 MW load transfer in 2032 and 9 MW load transfer in 2033 to Bensonhurst No. 2.

Greenwood (post-transfer)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Bay Ridge	250	259	267	272	276	278	281	277	271	193
Park Slope	214	216	217	217	218	218	219	220	220	221
Radial	23	24	24	24	24	0	0	0	0	0
Total Load	487	499	508	513	518	496	500	497	491	414
Electrification Adjustment	9	14	19	24	29	35	42	50	56	53
Other Adjustments	-8	-13	-16	-20	-20	-15	-17	-20	-20	-21
Net Load	488	500	511	517	527	516	525	527	527	446
Capability	511	511	511	511	511	511	511	511	511	511
Capability w/Transformer upgrades				537	537	537	537	537	537	537

The adjacent Bensonhurst No. 1 and No. 2 Area Substations have constrained 138 kV sub-transmission feeders beginning in 2032, furthermore the Greenwood 138 kV TLA deficits start in 2030, accelerating the need to move load out of Bensonhurst No. 1 and No. 2 load pocket. With these factors, transferring the approximately 80 MW load from Greenwood Area Substation to the adjacent Bensonhurst No. 1 and No. 2 load pocket would only result in overloads of the Bensonhurst 138 kV sub-transmission feeders.

These load relief measures will address load demand at the Greenwood 27 kV Distribution Area Substation, until Industry City 27 kV Distribution Area Substation is established and the Bay Ridge network split of approximately 80 MW can be executed in 2034. The establishment of the Industry City 27kV Distribution Area Substation will address future load growth needs in South Brooklyn, offering distribution benefits of shorter feeder runs and future feeder load relief reductions along with de-loading Greenwood 27k V Distribution Area Substation and the Greenwood 138 kV TLA.

Relationship to Broader Company Plans, Initiatives and the NYS Climate Leadership and Community Protection Act

The Company expects general increases in load, as well as electrification of vehicles and non-heating appliances. Load projections in the 2025 – 2034 Ten Year Pre-liminary Load Relief Program indicate that the Brooklyn networks will encounter increasing overloads in ensuing years, with the Greenwood 27 kV Distribution Area Substation exceeding its station design capability. To address reliability design criteria and build in resiliency for various contingency events, the new Sunset Park 345 kV Transmission Substation will be placed into service by 2034. This project will improve the reliability of the Bay Ridge and Park Slope Networks by allowing the Company to reduce network sizes and will establish feasible resiliency options for various contingency events, which are not available with the existing distribution system design. This new 345 kV transmission substation will also provide potential points of interconnection and for the connection of future distribution substations, such as the planned Industry City Area Substation.

By enabling load splits and smaller distribution networks in the Greenwood TLA, this project will progressively increase the reliability of the associated networks in both the near and long term and alleviate issues which limit the load capacity in the Greenwood 27 kV Distribution Area Substation. Once the project is in service, it will be more feasible to transfer out or partially restore the load emanating out of Greenwood 27 kV Distribution Area Substation, minimizing the impact of outages to customers. It will help the Company avoid public safety issues related to network failures and significant damage to Company equipment.

The Project will facilitate achievement of State and City emissions goals by facilitating electrification. The Project will enable 91 MW of capacity beginning in 2034 to account for future customer growth from both the Bay Ridge Network and the Park Slope Network for electric vehicle adaptation, electrification of hot water heaters, stovetops, ovens, and clothes dryers in the summer, and new

business. Over the long run, as electrification of heating becomes more mainstream, the Project will also enable the additional margin to support progress towards New York State's clean energy future goals. Accordingly, this Project will enable achievement of CLCPA goals, not just by enabling electrification, but because it will benefit disadvantaged communities through improved reliability. This aligns with Con Edison's strategic objective to meet economy-wide net-zero GHG emissions in our service territories by 2050.

The operational measures and system improvements implemented with this project would be sufficient in addressing load growth across Company networks in Brooklyn.

This project is a core investment that enables the Company to continue to provide safe and reliable service, even as the nature of the grid changes. This aligns with Con Edison's strategic objective of providing world-class safety, reliability, and security, while managing the equity challenges of the energy transition.

2. Supplemental Information

Alternatives

Alternative 1
Nevins Street Area Substation – This alternative was originally proposed to address the Greenwood 27 kV Distribution Area Substation overloads. This project has been determined to be suboptimal, as the station would be required to relieve overloads at Water Street in 2032 and Plymouth St in 2039, per the latest load forecasts. This alternative would require extending fourteen (14) Bay Ridge Network feeders by 4.5 miles, compared to the current solution which would move the area station closer to the load and reduce feeder extensions by 2 miles each, saving approximately $250 million in distribution feeder costs.

Alternative 2
Gowanus Substation Expansion – The original alternative to the Sunset Park 345kV Transmission Substations consisted of a conversion of the existing single-ring bus at Gowanus Substation into a double-ring bus configuration. This alternative would have created several new points-of-interconnection (POIs) and five transformers capable of supplying distribution area substations. This alternative would have been built on the same Company-owned McKeon Door property as the proposed Brooklyn Expansion and would have rearranged several 345 kV feeders to achieve a reliable topology between the two 345 kV rings of the Gowanus Substation.

The existing 138 kV feeders that supply Bensonhurst Substations 1 and 2 would have been transferred to and supplied from the expanded Gowanus Substation, offering load relief to Greenwood 138 kV Transmission Load Area.

Ultimately, the effort required to rearrange the existing feeders to achieve the desired level of topological reliability was deemed too risky in terms of potential outage scheduling issues and relocation costs.

Risk of No Action

Risk 1: Load Shedding

In the event the Greenwood 27 kV Distribution Area Substation becomes overloaded, load shedding may be required during peak load conditions in the Bay Ridge and Park Slope Networks, which could cause thousands of customers to experience service outages.

Non-Financial Benefits

- Provide necessary reliability and resiliency in an area of New York City that serves many critical loads (e.g., airports, transportation hubs, and hospitals) in a densely populated area where many buildings have elevators and various equipment loads.
- Provide transmission capacity to enable local growth and facilitate the integration of future bulk renewable energy sources.
- Create points of interconnection (POIs) on the transmission system that do not currently exist, which could be used by third party generators seeking to supply clean energy to the Con Edison and New York State Transmission Systems
- Provide POIs for energy storage.
- Improve the resiliency of the Bay Ridge, Park Slope and South Brooklyn (new) networks and prepare them for electrification. Instead of solving overloads by upgrading cable with lesser reliability improvements, this program will solve future primary overloads while greatly increasing the reliability of the network by introducing new feeders.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)
N/A

2. Major financial benefits
N/A

3. Basis for estimate
This estimate is based on an order of magnitude estimate of project costs based on a conceptual design and historical costs for similar scopes of work. High-level estimates of total costs, by primary spend category, are shown below, including escalation, overheads, and contingency.

	Estimated Direct Costs	Esc., OH, & Other Loading[1]	Estimated Total	% of Total
01-Labor	$ 76,096,123	$130,479,939	$206,576,062	15.9%
02-MSH	$272,982,771	$262,545,592	$535,528,363	41.1%
03-Cont Svcs	$251,105,143	$241,504,429	$492,609,572	37.8%
09-Other	$ 34,639,760	$ 33,315,349	$ 67,955,109	5.2%
Total	**$634,823,797**	**$667,845,309**	**$1,302,669,106**	

[1] Includes: Escalation (18%), CE OH (0%), A&S (2.5%), PT&P (39.35%), AFDC (24.73%), and Contingency (30%)

Project Risks and Mitigation Plan

Risk 1:
Delays due to resource/support coordination. There are a large number of projects to expand the electric distribution system that may strain existing resources.

Mitigation Plan 1:
Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts. Expand hiring and increase the number of employees over the next few years to be able to handle the increased flow of work.

Risk 2:

Material Availability Issues

Mitigation Plan 2:
Engineering will work with Supply Chain to establish a cohesive plan that aligns with vendor lead times. Stay engaged with vendors to ensure lead times are maintained, and adjust the plan as needed if shortages are encountered.

Risk 3:
One major risk is for load to increase faster than forecasted which will cause load to exceed equipment ratings before completion of projects to de-load such equipment.

Mitigation Plan 3:
Start projects early and on a longer cycle to allow for acceleration if the need arises.

Technical Evaluation / Analysis
Due to overload constraints identified in the Greenwood 138 kV Transmission Load Area, a new area substation would be the only viable alternative for load relief. Con Edison is proposing a 345kV transmission substation to supply a new 27kV indoor area substation, with a proposed in-service date of summer 2034 for both stations. The project aims to transfer approximately 80MW from the Bay Ridge Network to a newly formed South Brooklyn Network.

Project Relationships (if applicable)
As discussed above, the Brooklyn Expansion project is necessary for establishing a new Sunset Park Transmission Substation to supply the new Industry City Area Substation. A related distribution project involves a load transfer from the Greenwood Area Substation to the Industry City Area Substation along with a network split of the Bay Ridge Network and the creation of a new South Brooklyn Network. Close coordination will be maintained between these projects.

3. Funding Detail ($000)

Historic Spend

	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Test Year* (O&M Only)	Forecast 2024
O&M	$0	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	N/A	$0
Capital	$0	$0	$0	$628	N/A	$34,361

2025-2029 Request:
Total Request by Year:

	2025	2026 (RY1)	2027 (RY2)	2028 (RY3)	2029
O&M	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	$0
Capital (Total)	$0	$70,000	$100,000	$240,000	$150,000
Labor	$0	$10,020	$13,696	$32,852	$17,851
M&S	$0	$22,314	$30,501	$73,164	$39,755
Contract Svcs.	$0	$24,502	$33,492	$80,336	$43,653
Other	$0	$2,800	$3,828	$9,181	$4,989
Overheads	$0	$10,364	$18,483	$44,467	$43,752

*The test year runs from 10/1/2023 to 9/30/2024

Central Operations / Substation Operations
2025-2029

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Atlantic Area Substation	
Project/Program Manager: Partha Roy	**Project/Program Number (Level 1):** 27724608
Status: ☒ **Initiation/Planning** ☐ **In-Progress (Projects Only)** ☐ **On-going (Programs Only)**	
Estimated Start Date: 2027	**Estimated Date In Service:** 2034
2025-2029 Funding Request ($000) **Capital:** $100,000 **O&M:** $0	

Work Description:
This is one of two projects designed together to alleviate the risk of potential future overloads at the Brownsville No. 2 Area Substation from future load growth. Under this project, the Company plans to build a new Area Substation, Atlantic, and, then, under a separate project implemented by Electric Operations, the Company will split the Richmond Hill Network, establishing the new Ozone Park Network, and transfer approximately 242 MW of load from the Brownsville No. 2 Area Substation to the new Atlantic Area Substation.

Atlantic Area Substation will be a new, indoor 27kV area substation that will be arranged in a double syn bus configuration with an initial build of four (4) 93.3 MVA 138/27kV transformer banks (and capacitors totaling 30 MVAR), with provisions for expansion to five (5) transformer banks. The station will be supplied from the 345kV Brooklyn Energy Hub and will provide 355 MW additional sub-transmission capacity to mitigate design capability deficiencies in the South Brooklyn load areas to meet projected load growth.

The major scopes of work remaining to be completed as part of this project include design and construction of the following project phases:

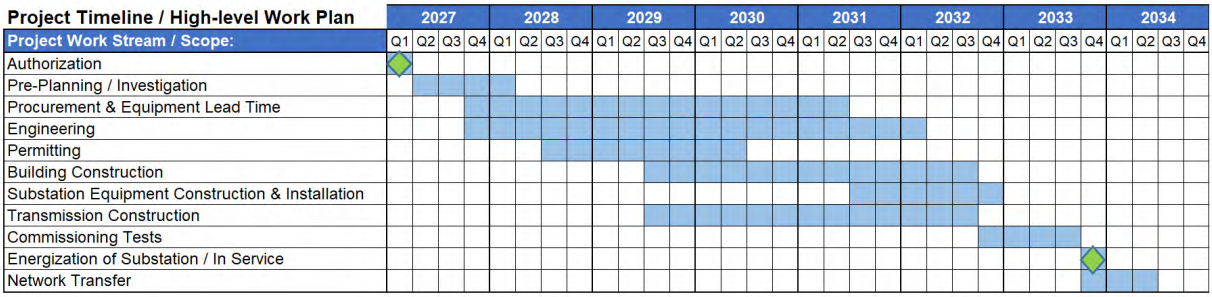
- Property Acquisition (underway)
- Engineering Package Development
- Site Demolition & Remediation
- Pour Foundation
- Erect Building Structure
- Complete Building Interiors (Mechanical, Electrical & Plumbing)
- Procure and Install Substation Equipment
- Complete sub-transmission feeder Installation
- Complete substation Terminations and Commissioning

Engineering and long lead equipment procurement began in 2027 for this project and station construction is expected to begin in 2029. Remaining major or long lead equipment purchases for this project include, but are not limited to:

Major Equipment Type	Number to be Purchased

138kV / 27 kV transformer banks	4
27kV Switchgear	5 Sections
27kV Secondary BUS	1800 ft.
Circuit Switcher	4
Circuit Interrupter	4
Capacitor Banks	2
L&P Transformers	2
Precast Trench	1200 ft.

The new Atlantic Area Substation is expected to be energized by May 2034. The estimated timeline to complete this project is below. This timeline is subject to change at any time, as the Company optimizes the project schedule and incorporates the final, detailed designs.



Justification Summary:

Con Edison delivers electricity to customers through transmission and distribution facilities. In general, a transmission substation supplies power to one or more distribution area substations, which in turn feed local electric networks that supply power to customers. The Brownsville Transmission load area feeds two area stations: Brownsville 1(BV1) and Brownsville 2(BV2). BV2 feeds the Richmond Hill Grid along with non-network feeder load. The target of this white paper is the construction of a new area substation, the Atlantic Area Substation, to support the split of the Richmond Hill network into two smaller networks. In 2034 both the Richmond Hill network & radial is forecasted to reach a total of 480 MWs, 96% of the BV2 substation's capability and, given continued load growth, the station will exceed its capability in 2036. This fast growth will also cause the combined load of BV1 and BV2 to exceed the rating of the sub-transmission feeders feeding the Brownsville load pocket by 2035. The sub-transmission feeders are listed below. The variability and unpredictability introduced by climate change, EV rate of deployment and electrification makes it likely that the exceedance of load over capacity may happen much sooner. Therefore, it is imperative that planning and construction starts by 2028 to allow the Company enough time to ramp up if the forecasts warrant it.

AREA SUBSTATION SUPPLY FEEDERS

Transmission	AREA SUBSTATION	Feeder 1	Feeder 2	Feeder 3	Feeder 4	Feeder 5	Feeder 6
Farragut 345kV	Brownsville No. 1	38B01	38B02	38B03	38B04	38B05	
345kV	Brownsville No. 2	38B01T	38B02T	38B03T	38B04T	38B05T	

The current 20-Year Load Forecast shows a continuing upward trend of peak demand growth at the network level driven by increased building and transportation electrification that continues to drive the need for load relief at the area station and transmission supply feeder level to maintain reliability design criteria and to meet climate resiliency objectives. Based on the 2024 forecast, the BV1 and BV2

Stations electric distribution networks (Ridgewood-5B, Crown Heights-3B, Richmond Hill-9B and radial systems) have projected loads that will cause the Brownsville sub transmission load feeders and substation to exceed their capability by 2035. The main drivers to load growth in the long-term forecast are climate change adjustments that we use in our design model, new business increase, electric vehicles deployment, buildings moving to full electric heating and organic load growth. The Company has an active BQDM program consisting of utility-side and customer-side solutions for the Brownsville load pocket to provide peak load reductions that will help to mitigate projected supply feeder capability deficiencies. Additionally, in 2026 a 60 MW load transfer from Brownsville No.1 Ridgewood network to Glendale Area Substation, and a 120 MW load transfer from Brownsville No.1 Crown Heights network to Gateway Park Area Substation are planned to provide load relief to the Brownsville 138 kV sub-transmission feeders. The split of the Richmond Hill network will improve the reliability of all networks by reducing the network and feeder lengths and by decreasing the average load per feeder. In addition, it will de-load the overloaded transmission and substation equipment. See below load forecast for the Brownsville transmission load pocket and associated stations BV1 and BV2.

Based on the Load Forecast of November 19, 2024
Independent MW Area Peaks - Summer

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Brownsville No. 1												
Crown Heights	210	214	218	102	103	104	104	105	106	106	107	108
Ridgewood	221	165	166	169	169	171	172	172	173	174	175	175
Total Load	431	379	384	271	272	275	276	277	279	280	282	283
Electrification Adjustment	5	12	15	15	18	22	28	33	38	46	52	60
Other Adjustments	-7	-8	-8	-8	-7	-3	-4	-4	-3	-5	-4	-5
Net Load	429	383	391	278	283	294	300	306	314	321	330	338
Capability	523											
Brownsville No. 2												
Richmond Hill	330	341	348	354	358	360	363	365	367	369	371	373
Radial	34	34	34	35	35	36	36	36	36	37	37	37
Total Load	364	375	382	389	393	396	399	401	403	406	408	410
Electrification Adjustment	3	6	12	18	25	34	43	52	62	74	86	98
Other Adjustments	-4	-4	-5	-5	-3	1	1	1	1	0	0	0
Net Load	363	377	389	402	415	431	443	454	466	480	494	508
	501											
Brownsville Nos. 1 & 2 Load	792	760	780	680	698	725	743	760	780	801	824	846
Feeder Peak Diversity	0	0	-1	2	0	0	0	0	0	0	0	0
Utility Sided Solutions	-15	-20	-21	-19	-19	-20	-20	-20	-19	-19	-14	-14
Customer Sided Solutions	-1	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-1
Net Load	776	729	747	652	668	694	712	729	750	771	799	831
138 kV Feeder Capability	771	771	771	771	771	771	771	771	771	771	771	771
Feeder Capability @ 141 kV	788											
138 kV Feeder Loading	98%	95%	97%	85%	87%	90%	92%	95%	97%	100%	104%	108%
[S.N. Rating = 847 Amperes]												
Farragut Y-winding Load	776	729	747	652	668	694	712	729	750	771	799	831
Capability	908											
Farragut Y-winding Loading	85%	80%	82%	72%	74%	76%	78%	80%	83%	85%	88%	92%
[TR No.4 S.E. 300-Hr Rating = 1017 Amps]												

To address the forecasted exceedance, Con Edison plans to split the Richmond Hill Network into two separate networks, a smaller Richmond Hill Network and the new Ozone Park Network. The new

Atlantic Distribution Area Substation will supply the new Ozone Park Network which will be established from the 242 MW of load transferred from the Brownsville 2 Distribution Area Substation.

The plan is to de-load the sub-transmission by splitting the Richmond Hill (9B) network into two separate networks: 9B west of the Brooklyn/Queens boundary line which will keep its Richmond Hill name and still be supplied by BV2 and 9B East of the cutline which will be transferred to the newly established Atlantic (formerly known as Gateway Park 2) Area Substation and will be named the Ozone Park network. This should provide about 242 MWs of load relief to the Brownsville sub transmission load pocket, BV2 area station and to the Transmission 345 KV equipment at Farragut which is also forecasted to overload a few years after the sub transmission feeders. The new Ozone Park network will consist of forty-three feeders and 242 MWs of 2024 load. The new smaller Richmond Hill network will consist of twenty-four feeders and an approximate net load of 174 MW in 2035. This will provide desperately needed load relief for the BV load pocket and allow for future load expansion. The number of feeders used to supply the new network has been maximized to allow for maximum load growth and reliability.

Based on the Load Forecast of November 19, 2024
Independent MW Area Peaks - Summer

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Brownsville No. 1												
Crown Heights	210	214	218	102	103	104	104	105	106	106	107	108
Ridgewood	221	165	166	169	169	171	172	172	173	174	175	175
Total Load	431	379	384	271	272	275	276	277	279	280	282	283
Electrification Adjustment	5	12	15	15	18	22	28	33	38	46	52	60
Other Adjustments	-7	-8	-8	-8	-7	-3	-4	-4	-3	-5	-4	-5
Net Load	429	383	391	278	283	294	300	306	314	321	330	338
Capability	523											
Brownsville No. 2												
Richmond Hill	330	341	348	354	358	360	363	365	367	369	141	142
Radial	34	34	34	35	35	36	36	36	36	37	0	0
Total Load	364	375	382	389	393	396	399	401	403	406	141	142
Electrification Adjustment	3	6	12	18	25	34	43	52	62	74	33	37
Other Adjustments	-4	-4	-5	-5	-3	1	1	1	1	0	0	0
Net Load	363	377	389	402	415	431	443	454	466	480	174	179
	501											
Brownsville Nos. 1 & 2 Load	792	760	780	680	698	725	743	760	780	801	504	517
Feeder Peak Diversity	0	0	-1	2	0	0	0	0	0	0	0	0
Utility Sided Solutions	-15	-20	-21	-19	-19	-20	-20	-20	-19	-19	-9	-9
Customer Sided Solutions	-1	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-1
Net Load	776	729	747	652	668	694	712	729	750	771	484	507
138 kV Feeder Capability	771	771	771	771	771	771	771	771	771	771	771	771
Feeder Capability @ 141 kV	788											
138 kV Feeder Loading	98%	95%	97%	85%	87%	90%	92%	95%	97%	100%	63%	66%
[S.N. Rating = 847 Amperes]												
Farragut Y-winding Load	776	729	747	652	668	694	712	729	750	771	484	507
Capability	908											
Farragut Y-winding Loading	85%	80%	82%	72%	74%	76%	78%	80%	83%	85%	53%	56%
[TR No.4 S.E. 300-Hr Rating = 1017 Amps]												

Due to the variability of the forecast, starting the distribution work early in BV2 will protect the system from earlier than expected overloads in both the sub transmission and the transmission equipment.

In addition to the organic growth of the forecast, new environmental and climate concerns are leading the city and state to promote electric heat and EV charging infrastructure that will increase load on the grid. This creates variability in the forecast which can result in the advancement of the need for load relief which is difficult to forecast so it is important that we start planning and construction to be able to ramp up if the load increases ahead of forecast. The implementation of Local Law 97, which mandates energy efficiency improvements and greenhouse gas emission limits in large commercial and residential properties, is expected to significantly increase the conversion to all-electric buildings. This law will likely result in a substantial rise in project volumes. Also, implementing NYC Local Law 154 is driving the electrification of heating and appliances for new construction. This is expected to increase the load on each new service versus historical standards. Electrification of transportation is also expected to increase throughout the rate case period. Customers requesting service with large loads, such as multifamily residential, retail, and large commercial are increasingly installing EV charging infrastructure. Increased adoption and installation of light duty electric vehicle chargers in existing parking areas and in new buildings is expected to grow.

Relationship to Broader Company Plans, Initiatives and the NYS Climate Leadership and Community Protection Act:
This project is a core investment that enables the Company to continue to provide safe and reliable service, even as the nature of the grid changes. This aligns with Con Edison's strategic objective of providing world-class safety, reliability, and security, while managing the equity challenges of the energy transition.

This project supports the State's achievement of CLCPA and clean energy goals. This aligns with Con Edison's strategic objective to meet economy-wide net-zero GHG emissions in our service territories by 2050.

2. Supplemental Information

Alternatives
Alternative 1 description and reason for rejection

One alternative considered was to rely upon Customer Sided Solutions (CSS) such as energy efficiency programs to mitigate any future sub-transmission capacity deficiencies. Energy efficiency programs can provide cost-beneficial solutions across multiple customer segments by accelerating load relief through little-to-no cost energy efficient upgrades and may aid in the deferral of traditional solutions for multiple years. Based on the magnitude of load relief required to address the overload constraints under a limited time frame, it has been assessed that an energy efficiency program is not a viable option. There is no known contingency plan other than to pursue the identified traditional solution should this alternative be pursued and prove unable to meet the projected deficits.

Risk of No Action
An overload on the transmission feeders supplying Brownsville No. 1 and No. 2 Area Substations is predicted to occur. Many of Con Edison's Brooklyn and Queens area substations are near full capacity and do not offer the feasibility of load transfer. In the event the transmission feeders overload, load shedding may be required during peak conditions which would cause thousands of customers to encounter service outages.

Without pursuing the project, the Company networks will encounter the potential inability of maintaining reliable system power flow controls, system reliability and resiliency concerns and/or possible customer outages for an extended period during peak load conditions.

Additionally, should the construction of a new substation in Brooklyn be deemed necessary and no action has been pursued, there may not be sufficient time available to properly procure zoned land that would minimize costs. The Company faces the risk of procuring land for a new substation in an area that requires exercising eminent domain actions or at a distance that increases cost of construction due to increased transmission circuit mileage.

Non-Financial Benefits

This project will provide the necessary reliability and resiliency in an area of New York City that serves many critical loads (e.g., airports, transportation hubs, and hospitals) in a densely populated area where many buildings have elevators and various equipment loads. Relief of overloaded transmission feeders will ensure continued reliable service to the Brownsville load pocket and will allow the station to maintain the area substation N-1 reliability design criteria for long term projected load growth.

The increased capacity brought on by Atlantic offers the potential to minimize impact on customers during an area station event that limits station capacity. Resiliency options are not feasible in this load pocket without the use of rolling blackouts and mobile stations which require a time-intensive set-up. By introducing new area station capacity and splitting current networks into smaller load areas, the Company will be able to handle loss of station capacity during emergencies and its impact on customers.

Meeting New York's CLCPA goals will ultimately require the Company to build system capacity for an anticipated increase in load growth. With electrification of the City, as we move away from a carbon economy, we will require capacity in the affected networks to accommodate unprecedented load growth. Rapid load growth has the potential to leave the Company in a difficult position to address all the relief and reliability challenges in the near future.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)
N/A

2. Major financial benefits
N/A

3. Basis for estimate
No cost estimate has been completed for this station at this point since the Company must acquire property for the new area substation. However, the design is expected to be similar to that of the new Gateway Park No. 1 Area Substation and that order of magnitude conceptual estimate is being used as an initial proxy.

	Estimated Direct Costs	Esc., OH, & Other Loading[1]	Estimated Total	% of Total
01-Labor	$ 42,433,404	$ 83,023,300	$ 125,456,704	11.6%
02-MSH	$107,413,650	$117,741,500	$225,155,150	20.8%
03-Cont Svcs	$304,388,294	$333,654,600	$638,042,894	59.1%
09-Other	$ 43,773,200	$ 47,982,200	$ 91,755,400	8.5%
Total	**$498,008,548**	**$582,401,600**	**$1,080,410,148**	

[1]Includes: Escalation (18%), CE OH (14.07%), A&S (2.59%), PT&P (50.4%), AFDC (10.02%), and Contingency (30%)

Project Risks and Mitigation Plan

Risk 1:
Delays due resource/support coordination. There are a large number of projects to expand the electric distribution system that may strain existing resources.

Mitigation Plan 1:
Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts. Expand hiring and increase the number of employees over the next few years to be able to handle the increased flow of work.

Risk 2:
Material Availability Issues

Mitigation Plan:
Engineering will work with Supply Chain to establish a cohesive plan that aligns with vendor lead times. Stay engaged with vendors to ensure lead times are maintained, and adjust the plan as needed if shortages are encountered.

Technical Evaluation / Analysis
N/A

Project Relationships (if applicable)
This project supports the transfer of load from the Richmond Hill network, currently served by the Brownsville Area Station No. 2, and will be closely coordinated to support that load relief measure.

3. Funding Detail ($000)

Historic Spend

	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Test Year* (O&M Only)	Forecast 2024
O&M	$0	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	N/A	$0
Capital	$0	$0	$0	$0	N/A	$0

2025-2029 Request:

Total Request by Year:

	2025	2026 (RY1)	2027 (RY2)	2028 (RY3)	2029
O&M	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	$0
Capital (Total)	$0	$0	$5,000	$45,000	$50,000
Labor	$0	$0	$305	$2,729	$4,000
M&S	$0	$0	$2,260	$20,201	$20,000
Contract Svcs.	$0	$0	$1,600	$14,301	$15,000
Other	$0	$0	$210	$1,877	$1,680
Overheads	$0	$0	$625	$5,892	$9,320

*The test year runs from 10/1/2023 to 9/30/2024

APPENDIX 9

Source Data for Con Edison Marginal Cost of Service (MCOS) Filing

Capital Budgets for Transmission Substations

Major Rate Case 25-E-0072

Electric Infrastructure and Operations Panel (EIOP)

System Expansion & New Business Capital Expenditures (CapEx)

EIOP-7 Updated (UPD): 4/10/2025

EIOP-7: 1/31/2025

Transmission Substation	Data Source
Eastern Queens Transmission Substation (EQTS)	EIOP-7 UPD, Pages 54-63
Brooklyn Clean Energy Hub (BCEH)	EIOP-7, Pages 18-22

Central Operations / Substation Operations

2025-2029

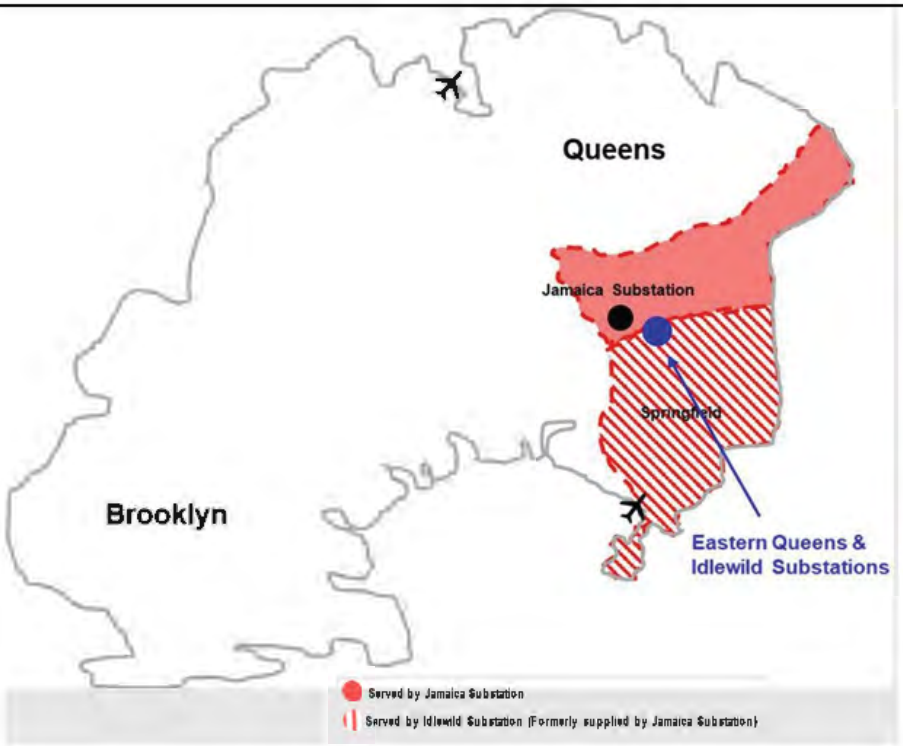
1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Eastern Queens Transmission Station	
Project/Program Manager: John Mccoy	**Project/Program Number (Level 1):** 26683129
Status: ☐ **Initiation/Planning** ☒ **In-Progress (Projects Only)** ☐ **On-going (Programs Only)**	
Estimated Start Date: 2023	**Estimated Date In Service:** 2028
2025-2029 Funding Request ($000) **Capital:** $557,743 **O&M:** $0	

Work Description:

The construction of the Eastern Queens Transmission Station is one part of a three-part project that will provide load relief to the Jamaica 27 kV Distribution Area Substation. The overall project will consist of three parts: 1. Building a new 138 kV transmission substation, the Eastern Queens 138 kV Transmission Substation ("Eastern Queens"), which will supply the new Idlewild 27 kV Distribution Area Substation; 2. Building the new Idlewild 27 kV Distribution Area Substation ("Idlewild"); and 3. Transferring 170 MW from the Jamaica Network to the new Idlewild 27 kV Distribution Area Substation, thereby creating the new Springfield Network ("Springfield"). The in-service date for the Eastern Queens Transmission Substation is April 2028, the in-service date for the Idlewild Distribution Area Substation is May 2028, and the Springfield Network in-service date will be May 2028.

A petition for the authorization and cost recovery of this three-part project to provide load relief to the Jamaica network was submitted by separate petition to the Commission in August 2023. In January 2024 the Commission issued an Order that authorized interim cost recovery through a surcharge until the Commission addresses the Company's next major electric base rate proceeding. (Case 22-E-0064 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, *Order Addressing Cost Recovery of Idlewild Project* (Issued and Effective January 19, 2024)).. The total estimated cost of the overall project included in the petition for all three projects was approximately $1.2 billion: approximately $592 million for the Eastern Queens Transmission Substation; approximately $380 million for the Idlewild Distribution Area Substation; and approximately $242 million for other electric facilities (distribution), e.g., feeders for the new Springfield Network.



The Eastern Queens Transmission Station will be co-located with the Idlewild 27 kV Distribution Area Substation on a vacant parcel of Company-owned land in Jamaica, Queens. Eastern Queens will be an indoor 138 kV Gas Insulated Switchgear Transmission Substation, arranged in a double ring bus configuration with provisions for future points of interconnection. The initial construction will include four 138 kV connections, expandable to five, to supply Idlewild. To connect Eastern Queens to the Con Edison Transmission System, the company will intercept and re-route existing 138 kV feeder 903 (between Jamaica 138 kV Substation and LIPA's Lake Success Substation) and existing 138 kV feeder 901 L and M (between Jamaica 138 kV Substation and LIPA's Valley Stream Substation). The 138 kV feeders 901L/M and 903 currently facilitate the LIPA wheeling service which will not be affected by this project. In the future, with additional expansion, Eastern Queens will be capable of supplying another Distribution Area Substation to provide load relief for Corona 27 kV Distribution Area Substations Nos. 1 and 2.

The major scopes of work to be completed to establish the Eastern Queens Transmission Substation include:

- Installation of a new 138kV Gas Insulated Switchgear system in a double ring bus configuration including nineteen circuit breakers [including two bus tie breakers], and associated disconnect switches, ground switches, potheads, CCVTs, PTs and CTs to provide new bus sections and new 138k feeder position.
- Installation of two di-electric pumping plants, each with a 10,000-gallon tank.
- Installation of a 500kW, 3-phase, 4-wire, 60 Hz diesel generator to provide emergency power for essential station service.
- Installation of fifty-four relay cabinets in each of two relay rooms (1st line and 2nd line relay rooms).
- Installation of two independent 125kV DC battery systems with two 125V DC load boards for each station.
- Installation of one AC/DC high voltage test set for each station.
- Intercept, uprate, and re-cable 138 kV feeders 901 L/M and 903 connecting LIPA and Jamaica Area Substation.

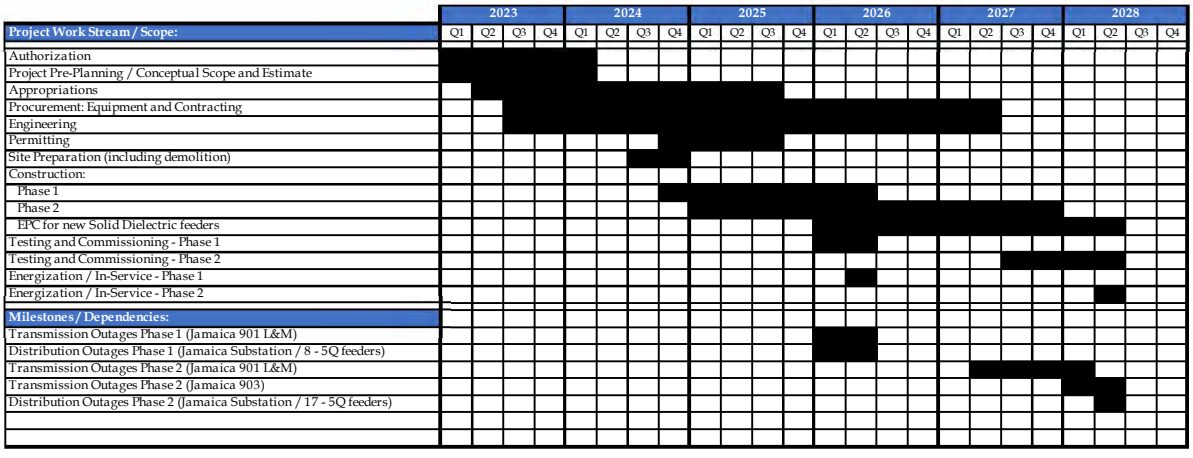
- Provision of required relay protection, automation, communication, and controls.

Engineering and long lead equipment procurement began in 2023 for this project and station construction is expected to begin in early 2025. Major equipment requirements for the project include, but are not limited to:

Major Equipment Type	Number to be Purchased
138kV Gas Insulated Switchgear Breaker Sections	20
Gas-insulated switchgear	1 lot
Circuit switchers	4
Capacitor banks	1
Solid di-electric transmission cable	5 miles
L&P Transformer	2

As the first phase of this work (Phase 1), the Company will install a 138 kV Phase Angle Regulator and a 138 kV/27 kV Transformer. This equipment will connect to 138 kV feeder 901 L/M as well as extend and connect to existing 27 kV distribution feeders. This work is required in the event the Company encounters additional forecasted load growth sooner than 2028 or unforeseen delays with the Project and will enable emergency power injection to the 27 kV Jamaica Network. This project provides for an emergency means to supply the Jamaica network with an additional resource to sustain service to the area. As options are very limited to supply an emergency resource due to the geographical location of the network and vast size of the network, this work is required.

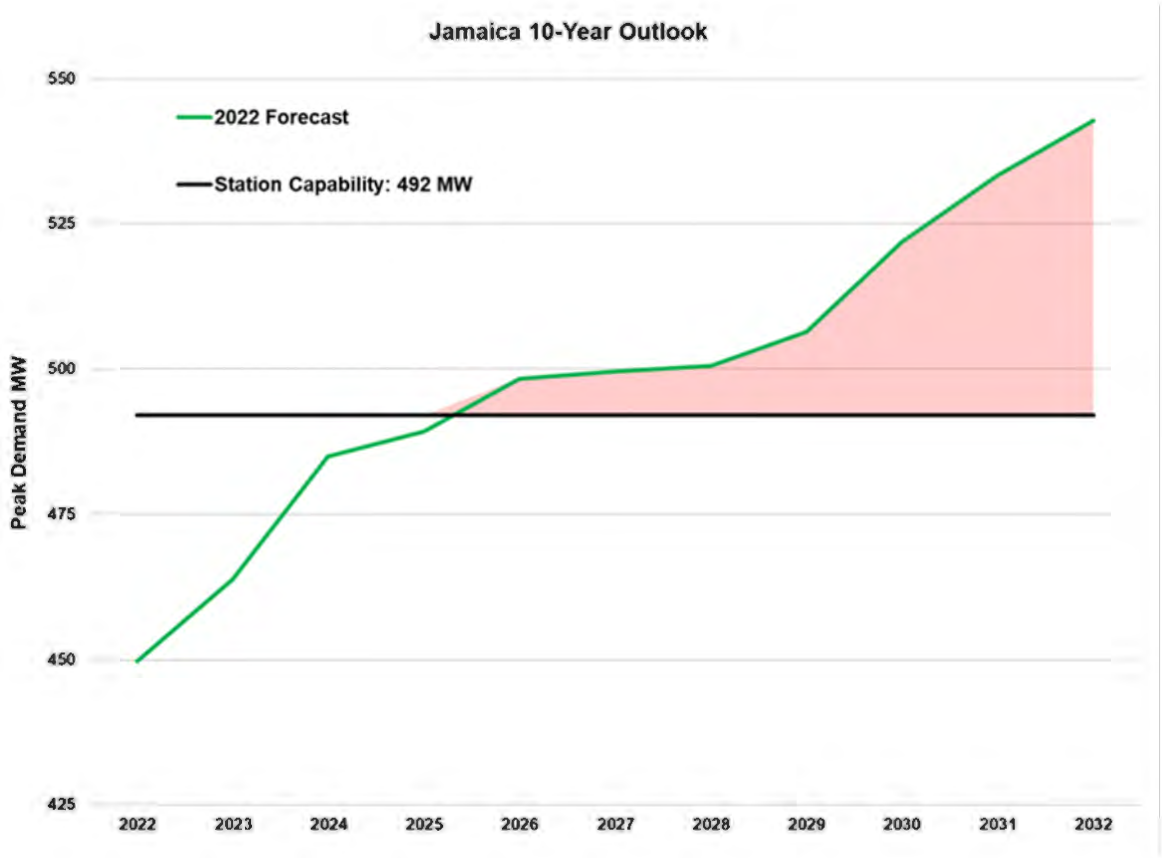
The estimated timeline to complete construction of the Eastern Queens Transmission Substation is below. This timeline is subject to change at any time, as the Company optimizes the project schedule and incorporates impacts of other projects and system performance.



Justification Summary:
To identify near-term load relief needs, the Company used a ten-year forecast of peak load conditions and compared those projections to the substation and network capabilities. Solutions identified to alleviate forecasted overloads are designed to do so on a ten-year basis and the Company prioritized solutions that are both technically viable and the least cost. The timing of investment for these solutions is based on their required lead times.

The Jamaica Network is Con Edison's highest peak demand network, forecasted at 455 MW for summer 2024. It is also one of the largest geographically, and one of the most isolated, being generally further away from other Company transmission and distribution area substations. The Network serves over 162,000 customers, including John F. Kennedy International Airport ("JFK Airport"), which is the country's sixth busiest airport with about 26.9 million passengers annually, the Long Island Railroad Jamaica Station, which is the country's third busiest train station, and four major MTA bus depots with approximately 700 buses that the MTA is planning to switch to electric battery powered vehicles.

The Company's current peak demand forecast for the Jamaica Network is as follows:



Based on the Company's most recent peak demand forecast, Distribution Area Station Planning has determined that the Jamaica 27 kV Distribution Area Substation will exceed its design capability in 2026. Over the last few forecasting cycles, the peak demand forecast for the Jamaica Network has generally increased year over year. Higher weather-adjusted peak demand experienced in the summer of 2023 was a key driver of the most recent forecast increase. Electrification of vehicles and non-heating appliances will continue to contribute to peak demand in the near term.

Con Edison's November 2024 load forecast, combined with distribution area station planning design criteria, shows that the peak demand at design conditions for the Jamaica Distribution Area Substation is projected to exceed its design capability of 492 MW as early as 2026 (see below). Further, the summer peak customer demand, which is weather normalized to a design Temperature Variable of 86,7 will equal the substation's design capability limit by 2026 and exceed the design capability limit by 12 MW in 2028. The exceedance is driven by a significant increase in electric demand due to vehicle electrification and economic growth. In particular, the forecast includes electrification related

to medium and heavy-duty vehicles, such as the buses, cargo vans, and trucks associated with the logistic and shipping operations prevalent in the Jamaica Network, and the $14 billion redevelopment program at JFK Airport.

Without the Project, the station is over 100% of capability in 2026 with net load increasing until capability is exceeded by over 100 MW in 2033.

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Jamaica										
Jamaica	468	483	491	497	503	506	516	518	519	521
Electrification Adjustment	9	16	21	25	34	45	57	69	82	96
Other Adjustments	-5	-5	-7	-8	-7	-2	-3	-3	-3	-3
Net Load	472	494	505	514	530	549	570	584	598	614
Capability	492									
Deficits		2	13	22	38	57	78	92	106	122

Based on the forecast, to avoid overloads at the Jamaica 27 kV Distribution Area Substation, the Company must pursue Non-Wires Solutions to provide load relief for Jamaica 27 kV Distribution Area Substation until 2028, when the long-term load relief solution of Eastern Queens, Idlewild and Springfield Network can be placed in service. To allow adequate time to build the new Eastern Queens station while maintaining reliability, the Company is pursuing a Non-Wires Solution to reduce peak load in the Jamaica Network for 2026 and 2027. The Company has consulted with Department Staff as required for Non-Wires Solutions, issued a request for proposals, received vendor proposals, committed funding, and filed notification of this Non-Wires Solutions Portfolio on March 16, 2023 in Case 19-E-0065.

Following energization of the Idlewild Area Substation in 2028, the Company plans to transfer approximately 170 MW from the Jamaica Network to a new network, Springfield, served by the Idlewilde station.

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Idlewild										
Springfield				170	172	173	176	177	178	178
Electrification Adjustment				9	12	15	19	24	28	33
Other Adjustments				-3	-3	0	-1	-1	-1	-1
Net Load				176	181	188	194	200	205	210
Capability				358						

Following this load transfer, capabilities usage at Jamaica will return to acceptable levels.

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Jamaica										
Jamaica	468	483	491	327	331	333	340	341	341	343
Electrification Adjustment	9	16	21	16	22	30	38	45	54	63
Other Adjustments	-5	-5	-7	-5	-4	-2	-2	-2	-2	-2
Additional NWS		-2	-13							
Net Load	472	492	492	338	349	361	376	384	393	404
Capability	492									

Relationship to Broader Company Plans, Initiatives and the NYS Climate Leadership and Community Protection Act

The Company expects general increases in load, as well as electrification of vehicles and non-heating appliances. Load projections in the 2023 – 2032 Ten Year Load Relief Program indicate that the

Queens networks will encounter increasing overloads in ensuing years, with the Jamaica 27 kV Distribution Area Substation exceeding its station design capability. To address reliability design criteria and build in resiliency for various contingency events, the new Eastern Queens 138 kV Transmission Substation will be placed into service by 2028. This project will improve the reliability of the Jamaica and new Springfield Networks by allowing the Company to reduce network sizes and will establish feasible resiliency options for various contingency events, which are not available with the existing distribution system design. This new 138 kV transmission substation will also provide potential points of interconnection for energy storage systems and for the connection of future distribution substations, such as the planned Hillside Area Substation.

By enabling load splits and smaller distribution networks in the Jamaica and Corona Transmission Load Areas, this program will progressively increase the reliability of the associated networks in both the near and long term. The Project will alleviate issues which limits the load capacity in the Jamaica and Corona 27 kV Distribution Area Substations. Once the project is in service, it will be more feasible to transfer out or partially restore the load emanating out of Jamaica and Corona No. 1 and No. 2 27 kV Distribution Area Substations, minimizing the impact of outages to customers. It will help the Company avoid public safety issues related to network failures and significant damage to Company equipment.

The Project will facilitate achievement of State and City emissions goals by facilitating electrification. The Project will enable 170 MW of future customer growth in the Jamaica Network and 176 MW of future customer growth in the Springfield Network for electric vehicle adaptation, electrification of hot water heaters, stovetops, ovens, and clothes dryers in the summer, and new business. Over the long run, as electrification of heating becomes more mainstream, the Project will also enable the additional margin to support progress towards New York State's clean energy future goals. Accordingly, this Project will enable achievement of CLCPA goals, not just by enabling electrification, but because it will benefit disadvantaged communities through improved reliability. This aligns with Con Edison's strategic objective to meet economy-wide net-zero GHG emissions in our service territories by 2050.

The operational measures and system improvements implemented with this project would be sufficient in addressing load growth across Company networks in Queens.

This project is a core investment that enables the Company to continue to provide safe and reliable service, even as the nature of the grid changes. This aligns with Con Edison's strategic objective of providing world-class safety, reliability, and security, while managing the equity challenges of the energy transition.

2. Supplemental Information

Alternatives
Alternative 1: An alternative solution is to rely on Non-Wires Solutions to mitigate any future substation capacity exceedances. Energy efficiency, and other Non-Wires Solutions can provide cost-beneficial solutions across different customer segments that may help defer traditional solutions.
Reason for rejection: Based on the magnitude of load relief required in the Jamaica Network, the Company has determined that Non-Wires Solutions are most appropriately suited as short-term solutions until Eastern Queens and Idlewild can be built. Therefore, there is no known contingency plan other than to pursue the identified traditional solution.

Alternative 2: An alternative solution is to conduct load transfers.

Reason for rejection: Overloads at the Jamaica 27 kV Distribution Area Substation are predicted to occur in the current planning horizon (i.e., 2026). There is insufficient capacity at any adjacent Queens 27 kV Distribution Area Substations to make a load transfer feasible. Corona No. 1, Corona No. 2, and Brownsville No. 2 (Richmond Hill network) are the only 27 kV Distribution Area Substations geographically abutting the Jamaica network.

Brownsville No. 2 27 kV Distribution Area Substation is constrained by the Farragut to Brownsville 138 kV sub-transmission feeders, which will require load relief in the 10-year planning horizon. The establishment of Gateway Park 27 kV Distribution Area Substation, to be supplied by four 138 kV feeders from the new 345 kV Brooklyn Clean Energy Hub, will provide relief for the Farragut to Brownsville 138 kV sub-transmission feeders.

Although the Corona No. 1 currently has capacity of about 93 MW to accept some load from the Jamaica 27 kV Distribution Area Substation, such a transfer is not feasible. The cost is high, and the work is complex as the required feeder work would have to cross or bypass multiple natural and manmade barriers including the North Grand Central Expressway, the Long Island Expressway, and multiple parks. The transfer would require running feeder extensions from the Flushing (07Q) network through the Rego Park (03Q) network into the Jamaica (05Q) network. These extensions would dramatically reduce the reliability of the Flushing (07Q) network and could result in overloading the existing 07Q feeders. The load transfer would require the creation of a subnetwork involving the separation and creation of a network fringe which reduces the secondary reliability of the area.

The Corona No. 2 27 kV Distribution Area Substation has a very limited margin to accept a load transfer, as only 14 MW of capacity is available at the end of the 10-year planning horizon. A transfer to Corona No. 2 would only move it closer to exceeding its design capability and require the Company to move up planned work for Corona No. 2 within the 10-year planning horizon.

Alternative 3: An alternative solution is to increase Jamaica bus uprates.
Reason for rejection: Bus uprates require replacing the existing 27 kV bus with a higher capacity bus throughout the majority of the substation and within the existing physical space. The scope requires removal and replacement of bus from each transformer and includes the distribution load bus sections.

This work requires sequential outages of each transformer and distribution bus section for approximately 2 months in duration each. The Jamaica 27 kV Distribution Area Substation topology is unique in that many distribution load bus sections contain six distribution feeders each. During each scheduled outage to replace the bus duct, a station supply transformer and the associated distribution feeders are required to be out of service. For most of the scheduled outages, this means six distribution feeders will be out of service for the duration of the upgrade. During these long periods of time, there is no way to recall the equipment to service should any additional station contingency or unforeseen weather event occur. The Company evaluated the bus uprates based on the 2021 forecast when the forecasted need arose in 2028. The 2022 forecast demonstrated that the Jamaica 27 kV Distribution Area Substation will exceed its design capability in 2026. As a result, given the five-year schedule to complete the work and the complexity executing the bus uprate work, the Company has decided to pursue a Non-Wires Solution Portfolio to provide load relief while the Project is constructed.

Risk of No Action
Risk 1: In the event the Jamaica 27 kV Distribution Area Substation becomes overloaded, load shedding may be required during peak load conditions in the Jamaica Network (the Company's largest network in both customers and peak usage) which could cause thousands of customers to experience service outages.

Risk 2: An additional risk in not pursuing the establishment of the Eastern Queens Transmission Station is potential impacts to critical customers (e.g., JFK Airport, LIRR Jamaica Station) served by the

Jamaica 27 kV Distribution Area Substation. Without pursuing the project, the Jamaica Network could be unable to maintain reliable system power flow controls and system reliability I addition to causing resiliency concerns and/or possible customer outages for an extended period during peak load conditions.

Non-Financial Benefits

- Provide necessary reliability and resiliency in an area of New York City that serves many critical loads (e.g., airports, transportation hubs, and hospitals) in a densely populated area where many buildings have elevators and various equipment loads.
- Provide transmission capacity to enable local growth and facilitate the integration of future bulk renewable energy sources.
- Create points of interconnection (POIs) on the transmission system that do not currently exist, which could be used by third party generators seeking to supply clean energy to the Con Edison and New York State Transmission Systems
- Provide POIs for energy storage.
- Improve network reliability index ratings compared to the present Jamaica Network, stemming from fewer megawatts transmitted over shorter feeder distances, fewer feeder components or possible points of failure, and less stress on the components.
- Provide for future load growth and electrification, including:
    - The transfer will allow the future creation of dedicated cubicles to transfer the JFK airport load. This will avoid unnecessary outages involving network transformers or other points of potential failure, thereby increasing the reliability for JFK. These dedicated feeders will also allow for future expansion of JFK load without any need for additional infrastructure investments for load relief.
    - The non-network load area being transferred to the new Distribution Area Substation will experience large load increases due to climate change electrification and increased use of EV. The extra capacity created will enable future expansion by using these non-network feeders to supply Multibanks that can be expanded to create localized grids with improved reliability.
    - Feeders containing 4 kV stations that also supply a 27 kV secondary network are known to cause load shifts on the 27 kV grid as the load transfers to nearby feeders after feeder contingencies. The large 27 kV network load remaining in Jamaica will benefit from removing this risk factor. When a 27 kV feeder that is connected to the 4 kV grid fails, the load gets transferred via 4 kV interties to other 4 kV unit stations and their 27 kV supply feeders. Additionally, the secondary network redistributes the network load to other supplying feeders. This can cause substantial amounts of load to be transferred to related feeders. This sudden increase in load can stress the remaining in-service 27 kV feeders supplying the load area and cause feeders to trip during multiple contingency events. The new Springfield network will supply mostly 4 kV load with limited 27 kV network load while the remaining Jamaica network will have minimum 4 kV station load, reducing risk to both networks.
    - The existing Jamaica 27 kV feeders are large and heavily loaded in terms of MW per feeder. The creation of the new network will divide the load area into two distinct networks, each with shorter feeder runs that carry fewer MWs. The secondary benefit of this will be a reduction in the network reliability index rating of the Jamaica and Springfield Networks.
    - No new secondary network fringe or boundary will be created since the load transferred is non network and the small network load pocket of 12 MWs is nested within the Jamaica 4 kV grid. This will avoid creating new weaknesses in the load areas being transferred since the new work does not change existing secondary network boundaries. Normally, new network boundaries require additional reinforcement to maintain reliability.

- This project will also improve the resiliency of the Jamaica and Springfield Network and prepare them for electrification. Instead of solving overloads by upgrading cable with lesser reliability improvements, this program will solve future primary overloads while greatly increasing the reliability of the network by introducing new feeders.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)
N/A

2. Major financial benefits
N/A

3. Basis for estimate

The funding request is based on an initial order of magnitude estimate based on the scope of work and major equipment described above.

EASTERN QUEENS 138KV SWITCHING STATION	Estimated Cost
Labor	**$ 99,698,000**
Labor - Substation Construction	$ 74,756,000
Labor - Transmission	$ 24,942,000
Substation Equipment:	**$ 140,046,000**
138kV GIS Bus Sections/Breakers	$ 116,586,000
Control Room Equipment, Relays, Test Sets, DC System, L&P and Other Electrical Equipment	$ 23,460,000
Transmission Equipment:	**$ 25,317,000**
Cable, Joints	$ 17,380,000
Pipe, Fittings, Dielectric Fluid, Tapecoat and Other Misc	$ 7,937,000
Contract Services	**$ 293,539,000**
Substation Contract Services - Building, Pumping Plants, Emerg Diesel Gnerator	$ 123,362,000
Transmission Contract Services - Civil, Conduit Install and Cable Installation	$ 170,177,000
Other Services	**$ 33,505,000**
Other - Substation Engineering, Technical, Testing and Support Services	$ 8,988,000
Other - Transmission Engineering, Technical, Testing and Support Services	$ 1,423,000
Other - Permits, Enivronmental, Equipment, Guard Services, freight, Remediation	$ 23,094,000
Grand Total	**$ 592,105,000**

Project Risks and Mitigation Plan

Risk 1:
Delays due to resource/support coordination. There are a large number of projects to expand the electric distribution system that may strain existing resources.

Mitigation Plan 1:
Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts. Expand hiring and increase the number of employees over the next few years to be able to handle the increased flow of work.

Risk 2:
Material Availability Issues

Mitigation Plan 2:
Engineering will work with Supply Chain to establish a cohesive plan that aligns with vendor lead times. Stay engaged with vendors to ensure lead times are maintained, and adjust the plan as needed if shortages are encountered.

Risk 3:
One major risk is for load to increase faster than forecasted which will cause load to exceed equipment ratings before completion of projects to de-load such equipment.

Mitigation Plan 3:
Start projects early and on a longer cycle to allow for acceleration if the need arises.

Technical Evaluation / Analysis
Due to overload constraints identified in the Jamaica Network on the 138kV sub-transmission system, a new area substation would be the only viable alternative for load relief. Con Edison is proposing a 138kV transmission substation to supply a new 27kV indoor area substation, with a proposed in-service date of summer 2028 for both stations. The project aims to transfer approximately 170MW from the Jamaica Network to a newly formed Springfield Network.

Project Relationships (if applicable)
Jamaica Bus Uprates
Establish Idlewild
Jamaica to Idlewild Load Transfer

3. Funding Detail ($000)

Historic Spend

	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Test Year* (O&M Only)	Forecast 2024
O&M	$0	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	N/A	$0
Capital	$0	$0	$0	$628	N/A	$34,361

2025-2029 Request:
Total Request by Year:

	2025	2026 (RY1)	2027 (RY2)	2028 (RY3)	2029
O&M	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	$0
Capital (Total)	$136,409	$172,310	$129,000	$120,024	$0
Labor	$16,369	$34,183	$21,469	$9,476	$0
M&S	$31,374	$51,766	$30,216	$80,830	$0
Contract Svcs.	$63,620	$35,800	$31,143	$5,023	$0
Other	$3,767	$8,805	$4,252	$2,200	$0
Overheads	$21,279	$41,756	$41,920	$22,495	$0

*The test year runs from 10/1/2023 to 9/30/2024

Central Operations / Substation Operations
2025-2029

1. Project / Program Summary

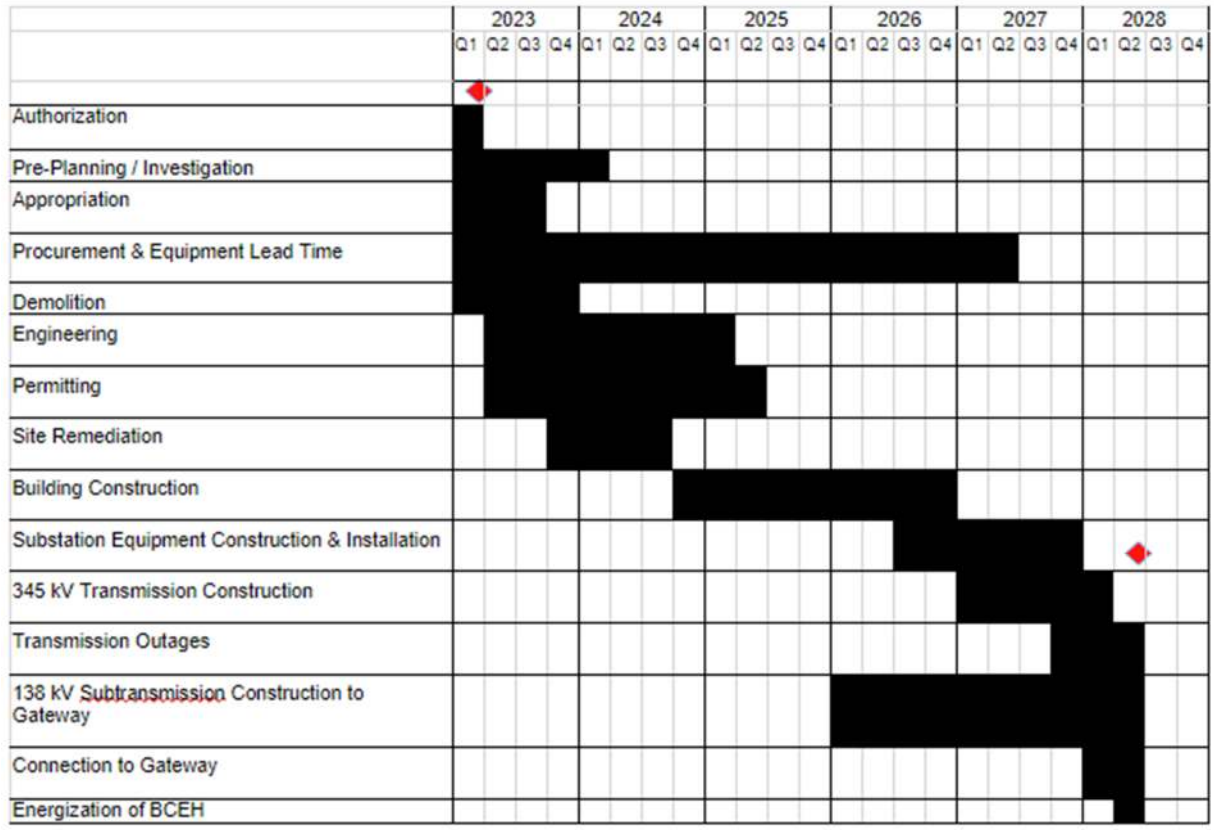
Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Brooklyn Clean Energy Hub Scalable Reliability Proposal	
Project/Program Manager: Bobby Kennedy	**Project/Program Number (Level 1):** 25493382
Status: ☐ **Initiation/Planning** ☒ **In-Progress (Projects Only)** ☐ **On-going (Programs Only)**	
Estimated Start Date: 2023	**Estimated Date In Service:** 2028
2025-2029 Funding Request ($000) **Capital:** $632,986 **O&M:** $0	

Work Description:
This project – as described in the April 20, 2023, Order Approving Cost Recovery for Clean Energy Hub (Case 20-E-0197) – will establish the Brooklyn Clean Energy Hub (BCEH), a new 345kV transmission substation needed for reliability and to facilitate the interconnection of clean energy to Con Edison's system. BCEH will create Points of Interconnection (POI) for large scale renewable resources, such as Offshore Wind Generation (OSW) and, potentially, other clean resources. The transmission station will also include five 345/138kV transformer banks that will provide supply to existing substations (Trade Center and Seaport Nos. 1 and 2) and future Area Substations.

The project is to be constructed at the (retired) Hudson Avenue Generating Station property in the Vinegar Hill neighborhood of Brooklyn. Various buildings on this property will be demolished to provide space for the construction of the BCEH. The demolition began in 2022.

The project will include the design and construction of a double ring bus substation with fourteen 345kV circuit breakers, six feeder positions for existing transmission lines and four 345/138kV transformer banks. The four transformer banks will provide sources for four 138kV underground transmission lines that will be included in the scope for a separate project to establish the Gateway Park Distribution Substation. The BCEH can be expanded to include a fifth transformer bank, and all banks will also be capable of supplying additional distribution substations in the future. Establishing the BCEH will include intercepting three existing 345kV feeders (61, 62 and 63) between the Farragut and Rainey 345kV Substations and diverting them into the Brooklyn Clean Energy Hub.

Engineering and long lead equipment procurement began in 2022 for this project and construction began in 2023. The in-service date for this project is December 2027. This timeline is subject to change at any time, as the Company optimizes the project schedule and incorporates impacts of other projects and system performance.



Justification Summary:
Based on the current electric forecast, the 138kV supply feeders for Brownsville Substation Nos. 1 and 2 are overloaded. The Company will implement various measures to alleviate the overloads, including small customer transfers, higher operational voltages and power factors, and a 60MW network transfer to an adjacent substation. Even with all these measures, the Brownsville supply feeders will be at their rated capacity again in 2028, at which time the only remaining load relief measure is to perform additional network transfers to the new Gateway Park Distribution Substation (Gateway).
Gateway will be a separate project, but it requires a new transmission substation as a supply source. The BCEH will be constructed to provide a reliable source for Gateway and future distribution substations and is scalable during construction to also provide future POIs for OSW.

The existing transmission substations in Brooklyn and Queens either do not have the physical space or the necessary equipment to supply an additional distribution substation. Gowanus Substation is an existing transmission substation that could be expanded to include the equipment needed to supply a distribution substation, but not in time to meet the reliability needs for Gateway in 2028. As a greenfield project, the BCEH can largely be constructed without scheduled outages to existing equipment and can be completed to provide supply to Gateway by summer 2028. The BCEH will also have the equipment and capacity necessary to supply additional distribution substations that will be required beyond 2028.

Gateway is needed to maintain reliability to customers in southeast Brooklyn and southwest Queens. Gateway cannot be placed into service without a transmission substation supply. The BCEH will establish a transmission supply to Gateway and can be completed by summer 2028.

In 2019, New York State passed the nation-leading Climate Leadership and Community Protection Act (CLCPA). CLCPA's targets are among the most rigorous of any major economy in the world and

include goals of 70% renewable energy by 2030 with 100% emanating from zero-emission electricity by 2040. The Accelerated Renewable Energy Growth and Community Benefit Act established the requirement to interconnect 9,000 MW of Offshore Wind (OSW) by 2035. The BCEH Scalable Reliability Option can be scaled to help achieve this goal by creating POIs for up to 4,500 MW of OSW. If additional re- configurations are completed, specifically re-routing 345kV feeders 46 and 48 to the BCEH, two more POIs can be created at Farragut Substation and could provide up to 1,500 MW more of OSW.

In summary, upon completion of all re-configurations, POIs for injection of up to 6,000 MW of OSW can be created: 4,500 MW at the Brooklyn Clean Energy Hub, and 1,500MW at its adjacent Farragut Substation.

Relationship to Broader Company Plans, Initiatives and the NYS Climate Leadership and Community Protection Act
The system improvements implemented with this project would be sufficient in managing constraints that limit renewable energy delivery within the system.

This program does not directly impact greenhouse gas emissions.

This project will strengthen the Con Edison transmission system and provide benefits across the service territory, including to disadvantaged communities served.

This project is a core investment that enables the Company to continue to provide safe and reliable service, even as the nature of the grid changes. This aligns with Con Edison's strategic objective of providing world-class safety, reliability, and security, while managing the equity challenges of the energy transition.

This project supports the State's achievement of CLCPA and clean energy goals. This aligns with Con Edison's strategic objective to meet economy-wide net-zero GHG emissions in our service territories by 2050.

2. Supplemental Information

Alternatives
There are two alternatives to this project.

The first alternative is to build the BCEH to its original scope, including "make-ready" POIs for OSW developers. This alternative can be completed in time to provide a source of Gateway but at an additional cost.

The second alternative is to build the BCEH to a reduced scope. This reduced scope would include construction of the BCEH as a single ring bus with twelve 345kV breakers, six 345kV transmission feeder positions and four 345kV/138kV autotransformers. This alternative can be completed in time to provide a transmission source for Gateway but would require extensive equipment outages and greater cost to expand in the future. Most importantly, it is not scalable during construction.

Risk of No Action
If this project is not completed by summer 2028, Gateway will not have a transmission supply. If Gateway does not have a transmission supply, there will not be adequate capacity to supply the

networks of southeast Brooklyn or southwest Queens during peak conditions and this could lead to widespread customer outages.

Non-Financial Benefits
This project will provide the necessary reliability and resiliency in an area of New York City that serves many critical loads (e.g., airports, transportation hubs, and hospitals) in a densely populated area where many buildings have elevators and various equipment loads. The project will also achieve environmental policy objectives and help to facilitate the achievement of CLCPA goals.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis (if required)
N/A

2. Major financial benefits
N/A

3. Basis for estimate
The initial order of magnitude estimate of project cost was based on an order of magnitude estimate of project costs based on a conceptual design and historical costs for similar scopes of work. High-level estimates of total costs, by primary spend category, are shown below, including escalation, overheads, and contingency.

Initial Brooklyn Clean Energy Hub Scalable Reliability Estimate:

	Estimated Direct Costs	Esc., OH, & Other Loading[1]	Estimated Total	% of Total
01-Labor	$ 38,202,880	$ 73,293,030	$111,495,910	13.8%
02-MSH	$112,359,200	$120,131,613	$232,490,813	28.7%
03-Cont Svcs	$183,028,038	$195,688,946	$378,716,984	46.8%
09-Other	$ 42,069,400	$ 44,979538	$ 87,048,938	10.7%
Total	**$375,659,518**	**$434,093,127**	**$809,752,645**	

[1]Includes: Escalation (16%), CE OH (14.07%), A&S (2.59%), PT&P (50.98%), AFDC (10.48%), and Contingency (30%)

An additional increase of approximately $45M is necessary to accommodate higher equipment costs for major equipment such as transformers, gas-insulated switchgear, and associated equipment.

Brooklyn Clean Energy Hub Estimate with Proposed Additional Funding:

	Estimated Direct Costs	Esc., OH, & Other Loading[1]	Estimated Total	% of Total
01-Labor	$ 38,202,880	$ 73,293,030	$111,495,910	12.7%
02-MSH	$134,107,002	$143,383,812	$277,490,814	32.0%
03-Cont Svcs	$183,028,038	$195,688,946	$378,716,984	43.2%
09-Other	$ 42,069,400	$ 44,979,538	$ 87,048,938	9.9%
Total	**$397,407,320**	**$457,345,326**	**$854,752,646**	

[1]Includes: Escalation (16%), CE OH (14.07%), A&S (2.59%), PT&P (50.98%), AFDC (10.48%), and Contingency (30%)

Project Risks and Mitigation Plan
Risk 1:

Delays due to resource/support coordination. There are a large number of projects to expand the electric distribution system that may strain existing resources.

Mitigation Plan 1:
Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts. Expand hiring and increase the number of employees over the next few years to be able to handle the increased flow of work.

Risk 2:
Material Availability Issues

Mitigation Plan 2:
Engineering will work with Supply Chain to establish a cohesive plan that aligns with vendor lead times. Stay engaged with vendors to ensure lead times are maintained, and adjust the plan as needed if shortages are encountered.

Technical Evaluation / Analysis
In order for New York State to meet its CLCPA requirements, the most effective system expansion is through a holistic / coordinated approach that would establish a single Brooklyn Clean Energy Hub that can accommodate large renewable (e.g., OSW) injections and consider system resiliency and future electrification. It is a feasible solution at lower cost that can be completed by 2027.

Project Relationships (if applicable)
N/A

3. Funding Detail ($000)

Historic Spend

	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Test Year* (O&M Only)	Forecast 2024
O&M	$0	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	$0	$0
Capital	$0	$0	$2,790	$62,308	N/A	$156,916

2025-2029 Request:
Total Request by Year:

	2025	2026 (RY1)	2027 (RY2)	2028 (RY3)	2029
O&M	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	$0
Capital (Total)	$243,000	$162,000	$121,500	$106,486	$0
Labor	$17,010	$13,778	$7,000	$8,700	$0
M&S	$53,460	$42,680	$22,000	$28,000	$0
Contract Svcs.	$113,604	$41,100	$35,000	$38,000	$0
Other	$17,535	$17,025	$7,772	$7,033	$0
Overheads	$41,391	$47,417	$49,728	$24,753	$0

*The test year runs from 10/1/2023 to 9/30/2024

APPENDIX 10

Source Data for Con Edison Marginal Cost of Service (MCOS) Filing

Capital Budgets for Load Transfers

Major Rate Case 25-E-0072

Electric Infrastructure and Operations Panel (EIOP)

System Expansion & New Business Capital Expenditures (CapEx)

EIOP-7 Updated (UPD): 4/10/2025

EIOP-7: 1/31/2025

Area Substation	Data Source
Idlewild (new)	EIOP-7 UPD, Pages 118-127
Gateway (new)	EIOP-7 UPD, Pages 85-96
Parkview	EIOP-7, Pages 27-36
Millwood West	EIOP-7 UPD, Pages 137-140
Cedar Street	EIOP-7, Pages 292-297
Nevins Street (new)	EIOP-7, Pages 195-204
Grasslands	EIOP-7 UPD, Pages 190-194
Hillside (new)	EIOP-7 UPD, Pages 41-47
Industry City (new)	EIOP-7 UPD, Pages 20-27
Atlantic (new)	EIOP-7 UPD, Pages 28-48

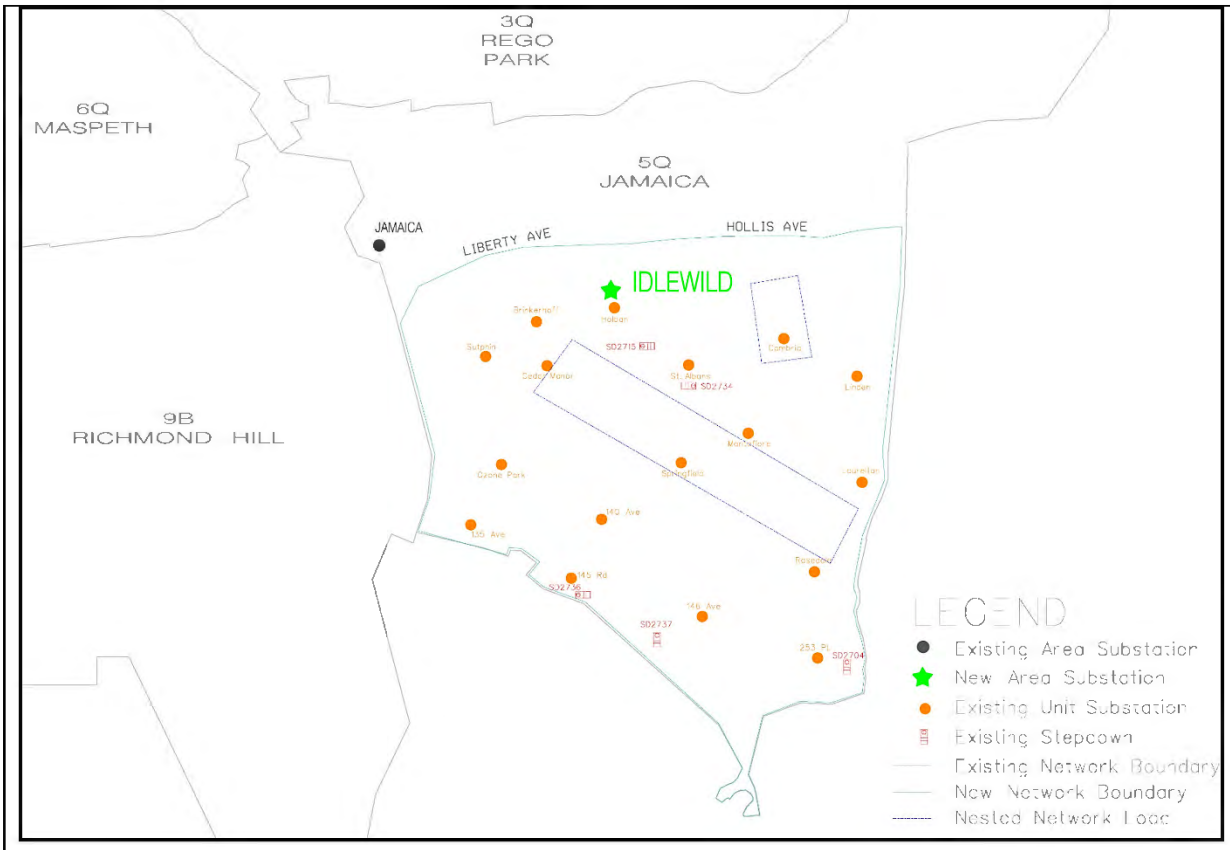
Electric Operations / Distribution Engineering
2025-2029

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Jamaica to Idlewild Load Transfer (2028)	
Project/Program Manager: Ailton Ramos	**Project/Program Number (Level 1):** 26758578
Status: ☐ **Initiation/Planning** ☒ **In-Progress (Projects Only)** ☐ **On-going (Programs Only)**	
Estimated Start Date: 2024	**Estimated Date In Service:** 2028
2025-2029 Funding Request ($000) **Capital:** $244,386 **O&M:** $0	

Work Description:
The Jamaica to Idlewild Load Transfer is one part of a three-part project that will provide load relief to the Jamaica 27 kV Distribution Area Substation. The overall project will consist of three parts: 1. Building a new 138 kV transmission substation, the Eastern Queens 138 kV Transmission Substation ("Eastern Queens"), which will supply the new Idlewild 27 kV Distribution Area Substation; 2. Building the new Idlewild 27 kV Distribution Area Substation ("Idlewild"); and 3. Transferring 170 MW from the Jamaica Network to the new Idlewild 27 kV Distribution Area Substation, thereby creating the new Springfield Network ("Springfield"). The in-service date for the Eastern Queens Transmission Substation is April 2028, the in-service date for the Idlewild Distribution Area Substation is May 2028, and the Jamaica to Idlewild Load Transfer/Springfield Network in-service date will be May 2028.

A petition for the authorization and cost recovery of this three-part project to provide load relief to the Jamaica network was submitted by separate petition to the Commission in August 2023. In January 2024 the Commission issued an Order that authorized interim cost recovery through a surcharge until the Commission addresses the Company's next major electric base rate proceeding. (Case 22-E-0064 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, *Order Addressing Cost Recovery of Idlewild Project* (Issued and Effective January 19, 2024)). The total estimated cost of the overall project included in the petition for all three projects was approximately $1.2 billion: approximately $592 million for the Eastern Queens Transmission Substation; approximately $380 million for the Idlewild Distribution Area Substation; and approximately $242 million for other electric facilities, e.g., feeders for the new Springfield Network.



Con Edison will transfer approximately 170 MW from the Jamaica Distribution Area Substation to the Idlewild Distribution Area Substation. The Company will run new 27 kV feeders from the Idlewild Distribution Area Substation to the seventeen existing 4 kV unit substations that comprise the current Jamaica 4kV grid load pocket and that will form the new Springfield Network. The load transfer includes: the Jamaica 4 kV load grid along with the associated Springfield Gardens Autoloop and two small, segregated load pockets of network load inside the larger 4 KV non network consisting of 12 MW of load. The work requires approximately 131,000 ft. of new duct, 425 manholes, 680 sections of primary cable, and 17 switches.

The major scopes of work to be completed to create the new Springfield Network include:

- Installing 133,595 trench feet of conduit
- Installing 695 sections of primary cable
- Installing 50 sections of secondary main
- Installing 425 manholes and 6 vaults
- Installing 17 switches
- Installing 6 120/208V transformers

Major or long lead equipment requirements for the project include, but are not limited to:

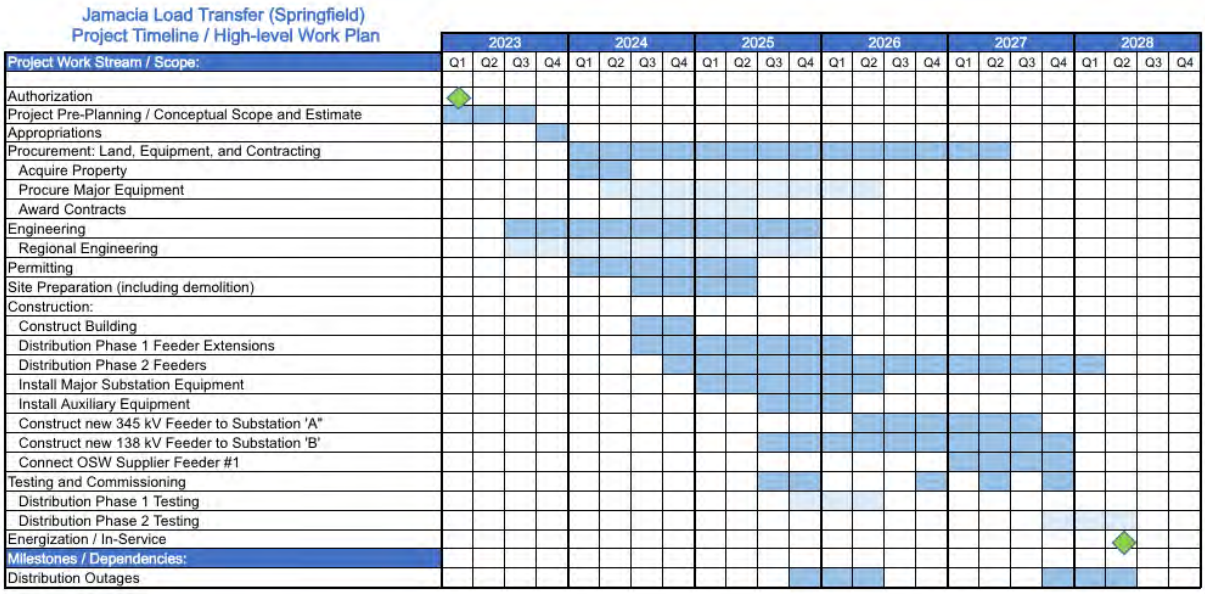
Major Equipment Type	Number to be Purchased
3-1000 EPR Primary Cable	689 sections
6 Inch HDPE Conduit [8 per section]	908,446 ft.
M-14 Manholes	425 manholes
6 Inch FRE Conduit [8 per section]	160,314 ft.

Intermesh Switches	17

Engineering and long lead equipment procurement began in 2023 for this project is expected to begin in early 2025.

The Company will install a 138 kV Phase Angle Regulator and a 138 kV/27 kV Transformer. This equipment will connect to 138 kV feeder 901 L/M as well as extend and connect to existing 27 kV distribution feeders. This work is required in the event the Company encounters additional forecasted load growth sooner than 2028 or unforeseen delays with the Project and will enable de-loading Jamaica station without impacting the Jamaica network. This project provides for an emergency means to supply the Jamaica network with an additional resource to sustain service to the area. As options are very limited to supply an emergency resource due to the geographical location of the network and vast size of the network, this work is required.

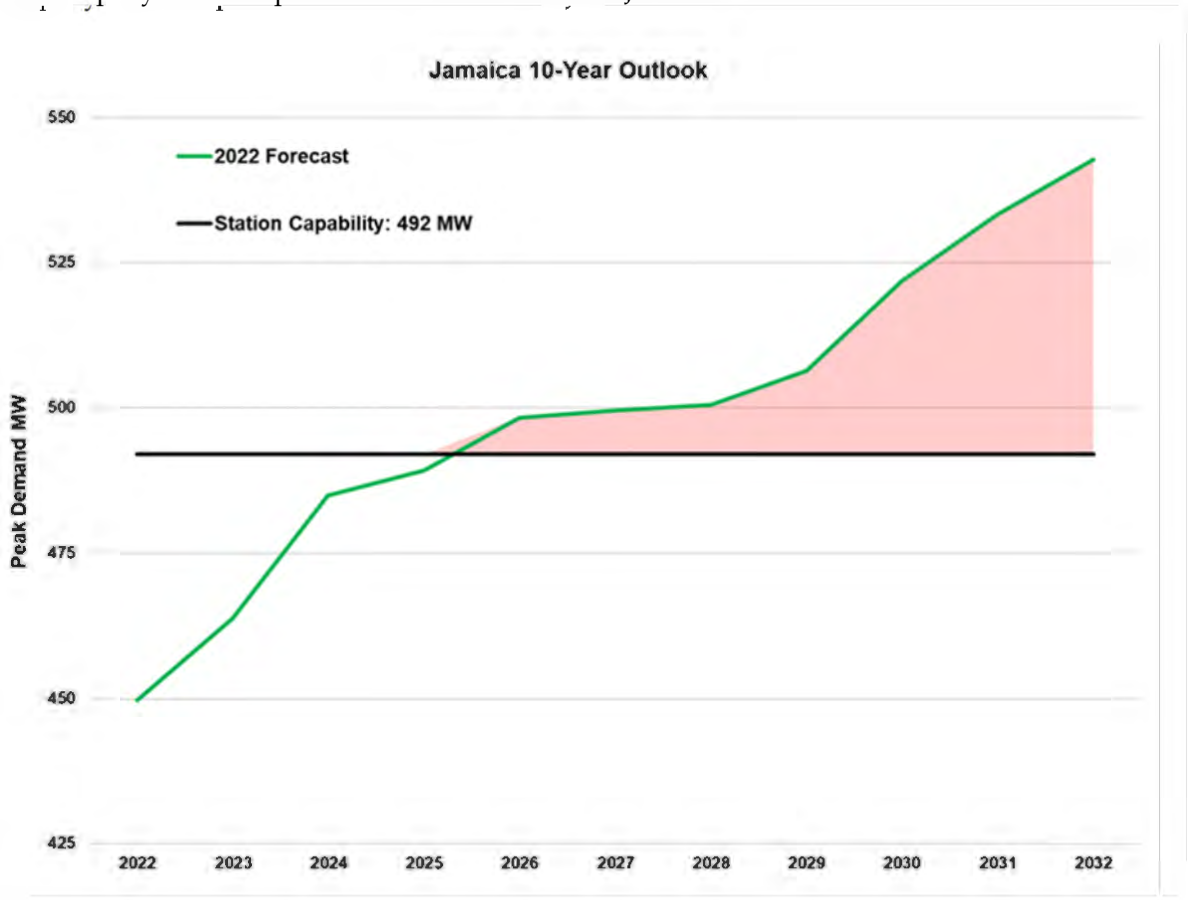
The estimated timeline for the creation of the Springfield Network and the transfer of load from Jamaica to the new Idlewild Area Substation is below. This timeline is subject to change at any time, as the Company optimizes the project schedule and incorporates impacts of other projects and system performance.



Justification Summary:
To identify near-term load relief needs, the Company used a ten-year forecast of peak load conditions and compared those projections to the substation and network capabilities. Solutions identified to alleviate forecasted overloads are designed to do so on a ten-year basis and the Company prioritized solutions that are both technically viable and least cost. The timing of investment for these solutions is based on their required lead times.

The Jamaica Network is Con Edison's highest peak demand network, forecasted at 450 MW for summer 2024. It is also one of the largest geographically, and one of the most isolated, being generally further away from other Company transmission and distribution area substations. The Network serves over 162,000 customers, including JFK International Airport, which is the country's sixth busiest airport with about 26.9 million passengers annually, the Long Island Railroad Jamaica Station, which is the country's third busiest train station, and four major MTA bus depots with approximately 700 buses that the MTA is planning to switch to electric battery powered vehicles.

The Company's current peak demand forecast for the Jamaica Network is as follows:



Based on the Company's most recent peak demand forecast, Distribution Area Station Planning has determined that the Jamaica 27 kV Distribution Area Substation will exceed its design capability in 2026. Over the last few forecasting cycles, the peak demand forecast for the Jamaica Network has generally increased year over year. Higher weather-adjusted peak demand experienced in the summer of 2023 was a key driver of the most recent forecast increase. Electrification of vehicles and non-heating appliances will continue to contribute to peak demand in the near term.

Con Edison's November 2024 load forecast, combined with distribution area station planning design criteria, shows that the peak demand at design conditions for the Jamaica Distribution Area Substation is projected to exceed its design capability of 492 MW as early as 2026 (see below). Further, the summer peak customer demand, which is weather normalized to a design Temperature Variable of 86,7 will equal the substation's design capability limit by 2026 and 2027 and exceed the design capability limit by 20 MW in 2028. The exceedance is driven by a significant increase in the electric demand due to vehicle electrification and economic growth. In particular, the forecast includes electrification related to medium and heavy-duty vehicles, such as the buses, cargo vans, and trucks associated with the logistic and shipping operations prevalent in the Jamaica Network, and the $14 billion redevelopment program at John F. Kennedy Airport ("JFK").

Without the Project, the station is at 100% of capability in 2026 with net load increasing until capability is exceeded by 100 MW in 2033.

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Jamaica										
Jamaica	468	483	491	497	503	506	516	518	519	521
Electrification Adjustment	9	16	21	25	34	45	57	69	82	96
Other Adjustments	-5	-5	-7	-8	-7	-2	-3	-3	-3	-3
Net Load	472	494	505	514	530	549	570	584	598	614
Capability	492									
Deficits		2	13	22	38	57	78	92	106	122

Based on the forecast, to avoid overloads at the Jamaica 27 kV Distribution Area Substation, the Company must pursue Non-Wires Solutions to provide load relief for Jamaica 27 kV Distribution Area Substation until 2028, when the long-term load relief solution of Eastern Queens, Idlewild and Springfield Network can be placed in service. To allow adequate time to build the new Eastern Queens station while maintaining reliability, the Company is pursuing a Non-Wires Solution to reduce peak load in the Jamaica Network for 2026 and 2027. The Company has consulted with Department Staff as required for Non-Wires Solutions, issued a request for proposals, received vendor proposals, committed funding, and filed notification of this Non-Wires Solutions Portfolio on March 16, 2023, in Case 19-E-0065.

Following energization of the Idlewild Area Substation in 2028, the Company plans to transfer approximately 170 MW from the Jamaica Network to a new network, Springfield, served by the Idlewilde station.

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Idlewild										
Springfield				170	172	173	176	177	178	178
Electrification Adjustment				9	12	15	19	24	28	33
Other Adjustments				-3	-3	0	-1	-1	-1	-1
Net Load				176	181	188	194	200	205	210
Capability				358						

Following this load transfer, capabilities usage at Jamaica will return to acceptable levels.

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Jamaica										
Jamaica	468	483	491	327	331	333	340	341	341	343
Electrification Adjustment	9	16	21	16	22	30	38	45	54	63
Other Adjustments	-5	-5	-7	-5	-4	-2	-2	-2	-2	-2
Additional NWS		-2	-13							
Net Load	472	492	492	338	349	361	376	384	393	404
Capability	492									

Relationship to Broader Company Plans, Initiatives and the NYS Climate Leadership and Community Protection Act

The project provides the capacity for additional load growth, which will enable customers to adopt electrification, clean energy technologies, and reduce the use of fossil fuels. Specifically, the adoption of electric vehicles will lower GHG or other pollution which can provide beneficial impacts on emissions in the network.

By enabling load splits and smaller distribution networks in the Jamaica and Corona Transmission Load Areas, this program will progressively increase the reliability of the associated networks in both the near and long term. The Project will alleviate issues which limits the load capacity in the Jamaica and Corona 27 kV Distribution Area Substations. Once the project is in service, it will be more feasible to utilize the adjacent network for emergency restoration, significantly reducing the time to restore customers in significant emergency.

This project supports the State's achievement of CLCPA and clean energy goals. This aligns with Con Edison's strategic objective to meet economy-wide net-zero GHG emissions in our service territories by 2050. The Project will enable 170 MW of future customer growth in the Jamaica Network and 176 MW of future customer growth in the Springfield Network for electric vehicle adaptation, electrification of hot water heaters, stovetops, ovens, and clothes dryers in the summer, and new business. Over the long run, as electrification of heating becomes more mainstream, the Project will also enable the additional margin to support progress towards New York State's clean energy future goals. Accordingly, this Project will enable achievement of CLCPA goals, not just by enabling electrification, but because it will benefit disadvantaged communities through improved reliability.

This project is a core investment that enables the Company to continue to provide safe and reliable service, even as the nature of the grid changes. This aligns with Con Edison's strategic objective of providing world-class safety, reliability, and security, while managing the equity challenges of the energy transition. The operational measures and system improvements implemented with this project would be sufficient in addressing load growth across Company networks in Queens.

This project is a climate resilience investment that strengthens utility infrastructure to withstand extreme weather conditions and the physical impacts of climate change. This aligns with Con Edison's strategic objective to increase resilience of our energy infrastructure to adapt to climate change and address other threats and hazards.

2. Supplemental Information

Alternatives

Alternative 1: An alternative solution is to rely on Non-Wires Solutions to mitigate any future substation capacity exceedances. Energy efficiency, and other Non-Wires Solutions can provide cost-beneficial solutions across different customer segments that may help defer traditional solutions.
Reason for rejection: Based on the magnitude of load relief required in the Jamaica Network, the Company has determined that Non-Wires Solutions are most appropriately suited as short-term solutions until Eastern Queens and Idlewild can be built. Therefore, there is no known contingency plan other than to pursue the identified traditional solution.

Alternative 2: An alternative solution is to conduct load transfers.
Reason for rejection: Overloads at the Jamaica 27 kV Distribution Area Substation are predicted to occur in the current planning horizon (i.e., 2026). There is insufficient capacity at any adjacent Queens 27 kV Distribution Area Substations to make a load transfer feasible. Corona No. 1, Corona No. 2, and Brownsville No. 2 (Richmond Hill network) are the only 27 kV Distribution Area Substations geographically abutting the Jamaica network.

Brownsville No. 2 27 kV Distribution Area Substation is constrained by the Farragut to Brownsville 138 kV sub-transmission feeders, which will require load relief in the 10-year planning horizon. The establishment of Gateway Park 27 kV Distribution Area Substation, to be supplied by four 138 kV feeders from the new 345 kV Brooklyn Clean Energy Hub, will provide relief for the Farragut to Brownsville 138 kV sub-transmission feeders.

Although the Corona No. 1 currently has capacity of about 93 MW to accept some load from the Jamaica 27 kV Distribution Area Substation, such a transfer is not feasible. The cost is high, and the work is complex as the required feeder work would have to cross or bypass multiple natural and manmade barriers including the North Grand Central Expressway, the Long Island Expressway, and multiple parks. The transfer would require running feeder extensions from the Flushing (07Q) network

through the Rego Park (03Q) network into the Jamaica (05Q) network. These extensions would dramatically reduce the reliability of the Flushing (07Q) network and could result in overloading the existing 07Q feeders. The load transfer would require the creation of a subnetwork involving the separation and creation of a network fringe which reduces the secondary reliability of the area.

The Corona No. 2 27 kV Distribution Area Substation has a very limited margin to accept a load transfer, as only 14 MW of capacity is available at the end of the 10-year planning horizon. A transfer to Corona No. 2 would only move it closer to exceeding its design capability and require the Company to move up planned work for Corona No. 2 within the 10-year planning horizon.

Alternative 3: An alternative solution is to increase Jamaica bus uprates.
Reason for rejection: Bus uprates require replacing the existing 27 kV bus with a higher capacity bus throughout a majority of the substation and within the existing physical space. The scope requires removal and replacement of bus from each transformer and includes the distribution load bus sections.

This work requires sequential outages of each transformer and distribution bus section for approximately 2 months in duration each. The Jamaica 27 kV Distribution Area Substation topology is unique in that many distribution load bus sections contain six distribution feeders each. During each scheduled outage to replace the bus duct, a station supply transformer and the associated distribution feeders are required to be out of service. For most of the scheduled outages, this means six distribution feeders will be out of service for the duration of the upgrade. During these long periods of time, there is no way to recall the equipment to service should any additional station contingency or unforeseen weather event occur. The Company evaluated the bus uprates based on the 2021 forecast when the forecasted need arose in 2028. The 2022 forecast demonstrated that the Jamaica 27 kV Distribution Area Substation will exceed its design capability in 2026. As a result, given the five-year schedule to complete the work and the complexity executing the bus uprate work, the Company has decided to pursue a Non-Wires Solution Portfolio to provide load relief while the Project is constructed.

Risk of No Action
Risk 1: In the event the Jamaica 27 kV Distribution Area Substation becomes overloaded, load shedding may be required during peak load conditions in the Jamaica Network (the Company's largest network in both customers and peak usage) which could cause thousands of customers to experience service outages.

Risk 2: An additional risk in not pursuing the establishment of the Eastern Queens Transmission Station is potential impacts to critical customers (e.g., JFK Airport, LIRR Jamaica Station) served by the Jamaica 27 kV Distribution Area Substation. Without pursuing the project, the Jamaica Network could be unable to maintain reliable system power flow controls and system reliability I addition to causing resiliency concerns and/or possible customer outages for an extended period during peak load conditions.

Non-Financial Benefits
- Provide necessary reliability and resiliency in an area of New York City that serves many critical loads (e.g., airports, transportation hubs, and hospitals) in a densely populated area where many buildings have elevators and various equipment loads.
- Provide transmission capacity to enable local growth and facilitate the integration of future bulk renewable energy sources.
- Create points of interconnection (POIs) on the transmission system that do not currently exist, which could be used by third party generators seeking to supply clean energy to the Con Edison and New York State Transmission Systems
- Provide POIs for energy storage.

- Improve network reliability index ratings compared to the present Jamaica Network, stemming from fewer megawatts transmitted over shorter feeder distances, fewer feeder components or possible points of failure, and less stress on the components.
- Provide for future load growth and electrification, including:
    - The transfer will allow the future creation of dedicated cubicles to transfer the JFK airport load. This will avoid unnecessary outages involving network transformers or other points of potential failure, thereby increasing the reliability for JFK. These dedicated feeders will also allow for future expansion of JFK load without any need for additional infrastructure investments for load relief.
    - The non-network load area being transferred to the new Distribution Area Substation will experience large load increases due to climate change electrification and increased use of EV. The extra capacity created will enable future expansion by using these non-network feeders to supply multibanks that can be expanded to create localized grids with improved reliability.
    - Feeders containing 4 kV stations that also supply a 27 kV secondary network are known to cause load shifts on the 27 kV grid as the load transfers to nearby feeders after feeder contingencies. The large 27 kV network load remaining in Jamaica will benefit from removing this risk factor. When a 27 kV feeder that is connected to the 4 kV grid fails, the load gets transferred via 4 kV interties to other 4 kV unit stations and their 27 kV supply feeders. Additionally, the secondary network redistributes the network load to other supplying feeders. This can cause substantial amounts of load to be transferred to related feeders. This sudden increase in load can stress the remaining in-service 27 kV feeders supplying the load area and cause feeders to trip during multiple contingency events. The new Springfield network will supply mostly 4 kV load with limited 27 kV network load while the remaining Jamaica network will have minimum 4 kV station load, reducing risk to both networks.
    - The existing Jamaica 27 kV feeders are large and heavily loaded in terms of MW per feeder. The creation of the new network will divide the load area into two distinct networks, each with shorter feeder runs that carry fewer MWs. The secondary benefit of this will be a reduction in the network reliability index rating of the Jamaica and Springfield Networks.
    - No new secondary network fringe or boundary will be created since the load transferred is non network and the small network load pocket of 12 MWs is nested within the Jamaica 4 kV grid. This will avoid creating new weaknesses in the load areas being transferred since the new work does not change existing secondary network boundaries. Normally, new network boundaries require additional reinforcement to maintain reliability.
    - This project will also improve the resiliency of the Jamaica and Springfield Network and prepare them for electrification. Instead of solving overloads by upgrading cable with lesser reliability improvements, this program will solve future primary overloads while greatly increasing the reliability of the network by introducing new feeders.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)

N/A

2. Major financial benefits

This project will enable the Company to address transmission equipment overloads. Exceeding the capacity of the substation and transmission feeders could result in load shedding if contingencies occur during peak loading conditions. This would result in customer outages and increase the risk of equipment failure and adversely impacting the community served. The regulatory financial costs of load shedding customers and costs of replacing transmission/station equipment can be very costly to the company. This project will avoid those costs.

3. Basis for estimate
The funding request is based on an initial order of magnitude estimate based on the scope of work and major equipment described above. The unit costing method was used to estimate the cost for the distribution system establishment of the Springfield network. The number of required units of equipment and material and multiplied by a loaded unit cost that contains material, labor, and overheads. The initial scope of work was studied and specific units of work needed were obtained at a high level.

Activity	Units	Unit Cost	Total Cost
120/208V Transformer	6	$ 18,188	$ 109,130
Secondary Mains (sections, 250-ft each)	50	$ 18,509	$ 925,440
Street Ties (4 sets of 4-500)	24	$ 6,697	$ 160,733
3-2/0 EPR (splicing included) (sections, 250-ft each)	6	$ 36,357	$ 218,142
3-1000 EPR (splicing included) (sections, 250-ft each)	689	$ 139,216	$ 95,920,011
M14	425	$ 84,527	$ 35,923,890
Service Box	6	$ 12,888	$ 77,328
V-14	6	$ 134,490	$ 806,940
Roadway Conduit	133,595	$ 958	$ 127,930,572
Switches	17	$ 127,636	$ 2,169,819
		Total Estimated Cost	**$ 264,242,005**

Project Risks and Mitigation Plan
Risk 1: Permitting by the city, Park departments, MTA & LIRR Interference, find lanes for ducts to be installed.

Mitigation Plan 1: Identify issues early via surveys and engage stakeholders to get permits and find clear lanes.

Risk 2: Interference with city contractors/paving coordination

Mitigation Plan 2: Coordinate with city and DOT to get access and schedule work to avoid conflicts.

Risk 3: Crossing major roadways and parks.

Mitigation Plan 3: Avoid crossings by rerouting. If not possible engage early to find different construction techniques like boring to cross major roadways, train lanes and park if possible. Place area station closer to the load to be transferred to avoid difficult crossings.

Risk 4: Delays due resource/support coordination. There are a large number of projects to expand the electric distribution system that may strain existing resources.

Mitigation plan 4: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts. Expand hiring and increase the number of employees over the next few years to be able to handle the increased flow of work.

Risk 5: Material Availability Issues

Mitigation plan 5: Engineering will work with Supply Chain to establish a cohesive plan that aligns with vendor lead times. Stay engaged with vendors to ensure lead times are maintained, and adjust the plan as needed if shortages are encountered.

Risk 6: One major risk is for load to increase faster than forecasted which will cause load to exceed equipment ratings before completion of projects to de-load such equipment.

Mitigation Plan 6: Start projects early and on a longer cycle to allow for acceleration if the need arises.

Technical Evaluation / Analysis
N/A

Project Relationships (if applicable)
Jamaica Bus Uprates

3. Funding Detail ($000)

Historic Spend

	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Test Year* (O&M Only)	Forecast 2024
O&M	$0	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	N/A	$0
Capital	$0	$0	$0	$0	N/A	$22,400

2025-2029 Request:
Total Request by Year:

	2025	2026 (RY1)	2027 (RY2)	2028 (RY3)	2029
O&M	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	$0
Capital (Total)	$82,786	$74,300	$62,800	$24,500	$0
Labor	14,524	13,333	11,612	4,222	-
M&S	15,607	13,963	11,674	4,682	-
Contract Svcs.	21,277	19,155	16,171	6,324	-
Other	1,292	1,054	843	287	-
Overheads	30,087	26,796	22,500	8,985	-

*The test year runs from 10/1/2023 to 9/30/2024

Electric Operations / Distribution Engineering
2025-2029

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Flatbush Network Split - Bensonhurst No. 2 to Gateway Park No. 1	
Project/Program Manager: Frantz St. Phar	**Project/Program Number (Level 1):** 27708492
Status: ☒ **Initiation/Planning** ☐ **In-Progress (Projects Only)** ☐ **On-going (Programs Only)**	
Estimated Start Date: 2026	**Estimated Date In Service:** 2030
2025-2029 Funding Request ($000) **Capital:** $ 244,100 **O&M:** $0	

Work Description:
This project is one of several projects planned to address identified transmission load area constraints on the 138 kV system supplying the Greenwood Transmission Load Area (TLA) which feeds Area Substations in South Brooklyn. The Greenwood 138 kV TLA feeds three Area Substations: Greenwood 27 kV, Bensonhurst No. 1 and Bensonhurst No. 2.

Con Edison identified the Greenwood 138 kV TLA to be deficient, under its N-1/-1 Design Designation (i.e., one element out-of-service with the system secured for the loss of the next element), based upon continued growth in demand in the area driven by new business, electric vehicles, and building electrification. These new deficiencies are incremental since the Reliable Clean City (RCC) Projects were identified and approved to address local reliability needs resulting from DEC NO_x regulation which removed Gowanus / Narrows barge-mounted generators as a supply to the Greenwood 138 kV TLA. Con Edison will place in-service the 4th Gowanus – Greenwood 345/138 kV PAR controlled feeder; however, this installation will not solve for the full 10-year planning horizon leaving year 2030 and 2031 in a deficiency requiring the Flatbush Network Split – Bensonhurst No. 2 to Gateway Park No. 1 to be advanced to 2030.

This project will also de-load the Bensonhurst No. 2 (BH2) Area Substation in order to address the sub-transmission overloads of the 138KV system that feeds Bensonhurst No. 1 (BH1) and Bensonhurst No. 2 (BH2) Area Substations. Under the latest load forecast, the sub-transmission feeders that feed BH1 and BH2 are forecasted to reach capacity by 2033. However, there is variability in the forecast that can advance the year where the load will exceed capacity at the sub-transmission level. Therefore, this project seeks to principally de-load the sub-transmission feeders and, as an added benefit, also de-load BH2 area station for future years. By advancing this project from 2033 to 2030, deficiencies identified for both the Greenwood 138 kV TLA and BH1 & BH2 load pocket can be addressed by transferring load from BH2 to Gateway Park.

BH2 feeds the Flatbush network (4B) and the Brighton Beach network (11B). The Flatbush is a 263 MW net load network, 19-feeder network with approximately 143,000 electric customers in 2025. Con Edison is planning to de-load BH2 Area Station by splitting the 4B network into two separate load areas.

Flatbush consists of two clearly delineated and segregated load areas. The area north of Newkirk Avenue consists of secondary distributed network design. The area south and east of Newkirk Avenue consists of mostly a non-network radial system with an embedded network grid within the non-network area.

The current Flatbush grid south of Newkirk Avenue will be split from the rest of the Flatbush network north of Newkirk Avenue. The 4B network north of Newkirk Avenue will continue being supplied by BH2 and will still be known as the Flatbush Network. The 4B load South of Newkirk Avenue will be supplied by the newly established Gateway Park 1 (GP1) substation.

The new network will be named 'Kings Plaza Network'. The south side will be bounded by Newkirk Avenue/Ave D in the north, E.37 St./Brooklyn Ave/Flatbush Ave in the west, Williams Ave/Fresh Creek Basin in the east and the Belt Parkway/Lower NY Bay in the south. This new network will consist of 15 feeders and 137 MWs net load (projected 2030 load) and will be supplied by Gateway Park 1 (GP1) substation.

The now smaller more reliable Flatbush network will be supplied by 15 feeders from BH2 substation and will supply 170 MW (projected 2030 load) of load to the customers north of Newkirk Ave. These forecasted loads do not include electrification adjustments as the city transitions out of dependency on fossil fuels and adapts to climate change.

To supply the new 4B south network, Con Edison will extend 15 feeders from the newly established Gateway Park 1 station to the load area that will be segregated. The rest of the network north of Newkirk Avenue will continue being supplied by Bensonhurst 2. There are 15 feeders south of Newkirk Avenue. However, 11 of the 15 feeders supply networks both north and south of Newkirk Avenue while 4 feeders supply south of Newkirk Avenue only. The 11 feeders that feed both north and south of Newkirk Avenue will be split in half with the south feeder portions being picked up by the new feeder extensions from GP1.

Con Edison will be using 1000 mcm cable from GP1 to the pick-up points of 4B South to allow for future load growth. Figure 1 below shows the way the new feeders will run to pick up the load being dropped from the Flatbush Network.

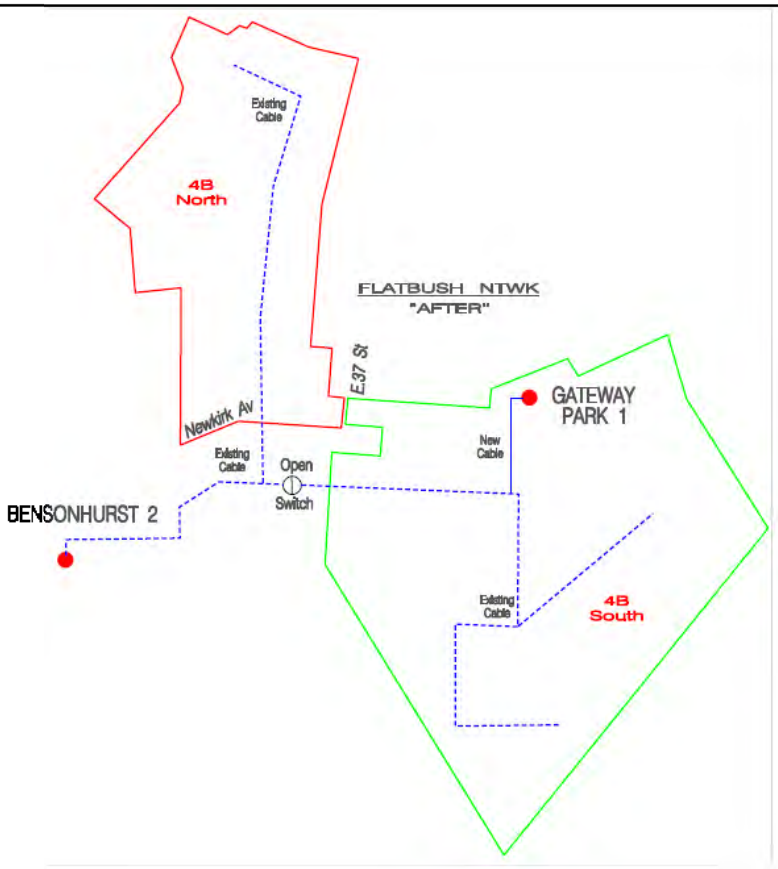


Figure 1. Overall feeder run from Gateway Park 1 and BH2 stations to create a new network south of Newkirk Ave Avenue to supplied by the New Gateway Park 1 Station.

Major or long lead equipment requirements for the project include, but are not limited to:

Major Equipment Type	Number to be Purchased
120/208V Transformer	15
3-2/0 EPR (splicing included)	15
3-500 EPR (splicing included)	30
3-1000 EPR (splicing included)	630
M14	336
M11-6	15
V13-6	15
Roadway Conduit 6"	84,000
Roadway Conduit 4" & 5"	4,500
Vacuum Switches	15
Cam-ops	15

Engineering will begin in 2025 for this project, construction is expected to begin in 2026 and is expected to be complete in 2030. This timeline is subject to change at any time, as the Company optimizes the project schedule and incorporates impacts of other projects and system performance.

Flatbush Network Split–Bensonhurst No. 2 to Gateway Park No. 1 Load Transfer
Project Timeline / High-level Work Plan

Project Work Stream / Scope:	2025				2026				2027				2028				2029				2030			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Engineering Design																								
Civil/Electrical Construction																								
Transfer Load / Establish New Network																								
Post-Intermesh Cleanup																								

Justification Summary:
The Greenwood Transmission Load Area (TLA) feeds three area substations: Bensonhurst No. 1, Bensonhurst No. 2 and Greenwood 27 kV Distribution Area Substations. BH2 feeds the Flatbush and Brighton Beach networks along with non-network loop load. This white paper describes the project that will split the Flatbush network into two smaller networks.

In 2025, the BH2 load is forecasted to have a net load of 380 MWs. In 2033 this BH2 is forecasted to have net load of 483 MWs. The rapid load growth on the BH2 Area Substation is the origin of the network split project. Due to forecasted load increase, the combined load of BH1 and BH2 will exceed the rating of the sub transmission feeders feeding the Bensonhurst load pocket. The sub transmission feeders feeding BH1 and BH2 are forecasted to overload by 2033. The sub transmission feeders are: 38B11, 38B12, 38B13, 38B14 and 38B15.

Greenwood 138kV	Bensonhurst No. 1	38B11	38B12	38B13	38B14	38B15
138kV	Bensonhurst No. 2	38B11T	38B12T	38B13T	38B14T	
	Greenwood	T1	T2	T3	T4	T5

The current 20-year load forecast shows an enduring upward trend of peak demand growth at the network level. The growth is driven by increased building and transportation electrification that continues to drive the need for load relief at the area station and transmission supply feeder level. Without this load relief it will be increasingly difficult, and soon impossible, to maintain reliability design criteria and meet climate resiliency objectives.

Based on the 2024 forecast, the BH1 and BH2 station electric distribution networks (Ocean Parkway-7B, Sheepshead Bay-10B, Flatbush-4B, Brighton Beach-11Bs and radial systems) have projected loads that will cause the Bensonhurst sub transmission load feeders to exceed their capability by 2033. The main drivers to load growth in the long-term forecast are climate change adjustments that the Company uses in its design model, new business increase, electric vehicles deployment, buildings moving to full electric heating, and organic load growth.

The split of the Flatbush network will improve reliability of all networks by reducing the network sizes and will partially de-load transmission equipment. See below load forecast for the Bensonhurst sub-transmission load pocket:

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Bensonhurst No. 1										
Ocean Parkway	154	156	158	160	162	162	163	164	164	165
Sheepshead Bay	148	150	151	153	154	155	156	156	157	157
Radial	50	51	52	52	54	55	56	58	59	60
Total Load	352	357	361	365	370	372	375	378	380	382
Electrification Adjustment	8	13	18	23	29	37	44	51	58	65
Other Adjustments	-6	-7	-9	-11	-11	-8	-9	-9	-10	-10
Net Load	354	363	370	377	388	401	410	420	428	437
Capability	511									
Bensonhurst No. 2										
Flatbush	276	281	288	294	298	300	302	304	305	307
Brighton Beach	99	103	104	106	107	110	113	114	115	116
Radial	12	12	13	13	13	13	13	13	13	14
Total Load	387	396	405	413	418	423	428	431	433	437
Electrification Adjustment	5	10	14	22	29	38	48	57	68	79
Other Adjustments	-12	-15	-16	-20	-19	-16	-17	-17	-18	-18
Net Load	380	391	403	415	428	445	459	471	483	498
Capability	551									
Bensonhurst Nos. 1 & 2 Load	734	754	773	792	816	846	869	891	911	935
138 kV Capability	874	874	874	874	874	874	874	874	874	874
138 kV and 0.97 PF Capability								904	904	904
138 kV Feeder Loading	84%	86%	88%	91%	93%	97%	99%	99%	101%	103%
[300-Hr S.E. Rating = 1109 Amps]										
[S.N. Rating = 966 Amps]										

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Bensonhurst Nos. 1 & 2 Load	767	778	787	795	797	800	824	845	867	892
138kV Capability	852	874								
138kV and 0.97 PF Capability										904
138kV Feeder Loading	90%	89%	90%	91%	91%	92%	94%	97%	99%	99%
[300-HR S.E. Rating = 1109 Amps]										
[S.N. Rating = 966 Amps										

The plan is to de-load the sub-transmission in 2030 by splitting the Flatbush (4B) network into two separate networks. The first is 4B north of Newkirk Ave (which will keep its Flatbush name and still be supplied by Bensonhurst 2). The second is 4B south of Newkirk Ave (which will be transferred to the newly established Gateway Park 1 Area Station and will be named the Kings Plaza network). The network split will transfer 130 MWs of base network load out of the Bensonhurst sub-transmission load pocket and to the Greenwood Transmission Load area beginning in 2030, providing load relief. The new 4B south network will consist of 15 feeders and 137 MWs of net load in 2030. The new 4B north network will consist of 15 feeders and 170MWs of load in 2030, as seen below.

Resulting Flatbush load transferred to Gateway Park beginning in 2030:

Bensonhurst No.2		2030	2031	2032	2033	2034
Flatbush Network	Base Network MW Transferred	130	131	132	132	133
	Electrification Transferred	14	17	21	25	29
	Other Adjustments Transferred	-7	-6	-7	-7	-7
	Total Flatbush Ave Load Transferred	**137**	**142**	**146**	**150**	**155**

Gateway Park resulting net load from picking up the new 4B south network (Kings Plaza network):

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Gateway Park										
Remsen				120	121	122	123	124	124	125
Kings Plaza						130	131	132	132	133
Total Load				120	121	252	254	256	256	258
Electrification Adjustment				5	6	21	25	30	35	41
Other Adjustments				-1	-1	-7	-7	-8	-7	-7
Net Load				124	126	266	272	278	284	292
Capability				361						

Resulting loading at BH2 Area Substation and BH1 & BH2 sub-transmission feeders:

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Bensonhurst No. 1										
Ocean Parkway	154	156	158	160	162	162	163	164	164	165
Sheepshead Bay	148	150	151	153	154	155	156	156	157	157
Radial	50	51	52	52	54	55	56	58	59	60
Total Load	352	357	361	365	370	372	375	378	380	382
Electrification Adjustment	8	13	18	23	29	37	44	51	58	65
Other Adjustments	-6	-7	-9	-11	-11	-8	-9	-9	-10	-10
Net Load	354	363	370	377	388	401	410	420	428	437
Capability	511									
Bensonhurst No. 2										
Flatbush	276	281	288	294	298	170	171	178	188	189
Brighton Beach	99	103	104	106	107	110	113	114	115	116
Radial	12	12	13	13	13	38	38	38	38	39
Total Load	387	396	405	413	418	318	322	330	341	344
Electrification Adjustment	5	10	14	22	29	24	31	37	43	50
Other Adjustments	-12	-15	-16	-20	-19	-9	-11	-11	-11	-11
Net Load	380	391	403	415	428	333	342	356	373	383
	540									
Bensonhurst Nos. 1 & 2 Load	734	754	773	792	816	734	752	776	801	820
Feeder Peak Diversity	-10	-11	-14	-14	-16	-16	-17	-18	-17	-18
Net Load	724	743	759	778	800	718	735	758	784	802
138 kV Capability	874									
138 kV Feeder Loading	83%	85%	87%	89%	92%	82%	84%	87%	90%	92%

[S.N. Rating = 966 Amps]

The Greenwood Transmission Load Area (TLA) feeds three Area Substations: Greenwood 27 kV, Bensonhurst No.1 and Bensonhurst No.2. As part of Con Edison's 2024 Local Transmission Plan (LTP), Transmission Planning has identified Greenwood 138 kV Transmission Load Area (TLA) to be deficient under its N-1/-1 Design Designation starting in year 2030. Previously, there were plans to de-load the Greenwood TLA by splitting the Bay Ridge network out of the Greenwood Area Station and establishing a new area station named Nevins Street. This project to split the Flatbush Network and transfer from Bensonhurst No. 2 to Gateway Park No. 1 has been advanced to 2030 and will now solve the Greenwood TLA.

Since load forecasts can be unpredictable, completing this portion of the BH2 project will protect the system from unexpected overloads in both the sub-transmission and the transmission equipment.

In conclusion, this project will not only alleviate the projected overloads on the Greenwood 138 kV TLA it will also alleviate the projected overload on the BH2 network,.

Relationship to Broader Company Plans, Initiatives and the NYS Climate Leadership and Community Protection Act
This project will not directly impact greenhouse gas emissions.

The Company expects general increases in load, as well as electrification of vehicles and heating. The BH sub transmission load pocket will encounter increasing overloads in the future when load increases to the point of matching equipment rated capacity. This will also happen to BH2 area station but at a later date.

To address reliability design criteria and build in resiliency for various contingency events, the new Gateway Park substation will be placed into service by 2028 in order to de-load the Brownsville Load pocket. By 2030, the Company plans to do a second load transfer into GP1 from the BH load pocket.

This project will improve the reliability of the Flatbush and Brighton Beach Networks by allowing the Company to reduce network sizes and will establish feasible resiliency options for various contingency events, which are not available with the existing distribution system design. Disadvantaged communities and underserved communities will benefit from this project by allowing electrification and EV deployment due to the increased station capacity. It will allow cleaner, greener sources of energy with reduced pollution and cleaner air in the DAC areas. The Project will facilitate achievement of State and City emissions goals by facilitating electrification.

The Project will enable about 130 MWs of future customer growth in the networks fed by the Bensonhurst load pocket and also in the new Kings Plaza Network. This will support the effort for electric vehicle adaptation, electrification of hot water heaters, stovetops, ovens, and clothes dryers in the summer, and new business.

Over the long term, as electrification of heating becomes more accepted and installed throughout the city, the project will also enable the additional margin to support progress towards New York State's clean energy future goals. Accordingly, this project will enable achievement of CLCPA goals, not just by enabling electrification, but because it will benefit disadvantaged communities through improved reliability. This aligns with Con Edison's strategic objective to meet economy-wide net-zero GHG emissions in our service territories by 2050.

The system improvements implemented with this project would be sufficient to address load growth across the networks supplied by the BH1 and BH2 Area stations: Flatbush, Brighton Beach, Ocean parkway, Sheepshead Bay and non-network loop load. This project is a core investment that enables the

Company to continue to provide safe and reliable service, even as the nature of the grid changes. This aligns with Con Edison's strategic objective of providing world-class safety, reliability, and security, while managing the equity challenges of the energy transition.

By enabling load splits and smaller networks, this program will increase the reliability of the associated networks in the near and long term. It will help the Company avoid public safety issues related to network failure, customer outages and significant damage to company equipment. Also, it will protect customers from any issues related to network shutdown.

Resiliency plans: this program will help during problems in the transmission and/or substation that limit the load capacity in the Brownsville, Water Street, and Greenwood substations. Once this project is complete, it will be more feasible to transfer out or partially restore the load coming out of the aforementioned area stations.

Flatbush is the 10th (out of 64) least reliable network in the network reliability rankings. This network ranking is projected to worsen in the coming years. The increasing load forecast and accompanying increase in load per feeder and reduction in the margins between the load and the feeder capacity will contribute to additional reliability challenges. The most economical and feasible solution is to reduce the load per feeder which will occur when we split the network load.

The plans proposed in this paper are synergistic and complementary to the Climate Change Implementation Plan. The reliability, resiliency and load relief improvements in this network are complementary and a necessary step to manage the climate risk imposed by global warming and electrification. This project is a climate resilience investment that strengthens utility infrastructure to withstand extreme weather conditions and the physical impacts of climate change. This aligns with Con Edison's strategic objective to increase resilience of our energy infrastructure to adapt to climate change and address other threats and hazards.

An added benefit of the work proposed in this white paper is that, as New York State continues its efforts to reduce greenhouse gas emissions, further electrification of the economy will challenge the secondary distribution system. Reducing load will decrease the load per feeder and transformers.

Risk management at the distribution level: By virtue of ranking in the top 10 in the NRI, with no expectations of being able to meaningfully reduce this number, the Flatbush network will be susceptible to network shutdown relative to most networks in the system. The consequences would be severe for the company and the public. Public safety, disruption of public transportation, severe damage to company equipment and customer outages would be some of the immediate consequences of reliability problems. PSC penalties, reputational damage, increased regulatory scrutiny and severe financial impact would be the consequences in the longer timeframe.

2. Supplemental Information

Alternatives
Alternative 1: The alternative solution is to transfer load out of the BH1 or BH2 area stations to nearby networks not part of the four networks being fed by the Bensonhurst sub-transmission feeders.

Reason for Rejection: There is no additional capacity in the three nearby stations: Greenwood 27 kV, Brownsville No.1 and Brownsville No.2.

Risk of No Action

An overload in the sub transmission feeders that feed BH1 and BH2 Area Stations is predicted to occur. Many of Con Edison's Brooklyn/Queens substations are near full capacity and do not offer the feasibility of load transfer. In the event of an area station overload, load shedding may be required during peak conditions which would cause thousands of customers to encounter service outages. Without pursuing the project, the Company networks will encounter the potential inability of maintaining reliable system power flow controls, system reliability and resiliency concerns and/or possible customer outages for an extended period during peak load condition.

Additionally, should the de-load of the sub transmission feeder be deemed necessary, and no action has been pursued, there may not be sufficient time available to de-load the sub transmission load pocket via the split of the Flatbush Network.

Non-Financial Benefits

This project will provide the necessary reliability and resiliency in an area of New York City that serves many critical loads and hospitals in a densely populated area where many buildings have elevators and various equipment loads. Relief of the sub transmission and the station will ensure continued reliable service to the Flatbush, Brighton Beach, Ocean Parkway and Sheepshead Bay networks and will allow the sub transmission load pocket and station to maintain the area substation N-1 reliability design criteria for long term projected load growth in this area of Brooklyn. This Project will also provide future relief to the Greenwood TLA which provides service Greenwood 27 kV, BH1 and BH2 Area stations.

The increased capacity in the sub transmission feeders brought on by transferring load out of BH2 offers the potential to minimize impact on customers during an area station event that limits station capacity. Resiliency options are not feasible in this load pocket without the use of rolling blackouts and mobile stations which require a time-intensive set-up. By introducing new area station capacity and splitting current networks into smaller load areas, the Company will be able to handle the loss of station capacity during emergencies and better mitigate the impact on customers. If capacity at Water Street, Brownsville or Greenwood stations is compromised, load can be swapped between stations, minimizing, or eliminating the need for load shedding during an event.

Meeting New York's CLCPA goals will ultimately require the Company to build system capacity for an anticipated increase in load growth. With electrification of the City, as we move away from a carbon economy, we will require capacity in the affected networks to accommodate unprecedented load growth. Rapid load growth has the potential to leave the Company in a difficult position to address all the relief and reliability challenges in the near future.

Customers will be satisfied with much less construction in the long term because the large number of overloads expected in the current system would be resolved with this project, at least for the Flatbush network. Otherwise, hundreds of sections will require load relief and excavation over the next few decades in different areas of this part of Brooklyn.

By decreasing the probability of a network shutdown, this program will increase the reliability and resiliency of the network in the long term. It will help the Company avoid public safety issues related to network failure, customer outages and significant damage to company equipment. Also, it will shield the Company from any reputational issues related to network shutdown.

There will be fewer customer disruptions. This project will also help reduce outages because less stress on the feeders and eliminate all major load relief projects that would otherwise be required.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)

N/A

2. Major financial benefits
A financial benefit of this work is cost avoidance at the 27 KV feeder distribution level. As load increases, the margins between the feeder ratings and feeder loads will decrease in the network to the point where extensive load relief will be needed to upgrade feeder cable. The network will require an increasingly large budget over the next several decades to address feeder overloads with little benefit to the reliability of the network. As the load increases, feeders will reach and then go beyond their rating. The standard method used to resolve overload is to install new duct and replace the overloaded section. This is an expensive proposition. An uptick in the load forecast through, for example, electrification of cars and electric heating, can increase the number of feeders that need expensive load relief. The work proposed in this paper will resolve all the overloaded sections by transferring loads out of existing feeders to new ones supplied by GP1.

Another cost savings is that the much lower load per feeder gained by introducing new equipment will reduce stress on the feeders during summer contingencies. Avoidance of penalties related to potential network shutdown is another benefit of this project. By reducing the load per feeder in the Flatbush grid, we will be able to better rebalance the load amongst the existing feeders and even consolidate feeders in Flatbush which would allow us to introduce new feeders in the other network fed by BH2, Bright Beach network.

3. Basis for estimate
The funding request is an initial order of magnitude estimate based on the scope of work and major equipment described above. The number of required units of equipment and material was identified and multiplied by a loaded unit cost that contains estimates of material, labor, escalation, overheads, and contingency. The initial scope of work was studied, and specific units of work needed were obtained at a high level.

Name	Units	Total Unit Cost	Total Cost
120/208V Transformer	15	$23,467	$352,000
3-2/0 EPR (splicing included)	15	$46,933	$704,000
3-500 EPR (splicing included)	30	$60,900	$1,827,000
3-1000 EPR (splicing included)	630	$179,821	$113,287,000
M14	336	$109,182	$36,685,000
M11-6	15	$53,400	$801,000
V13-6	15	$110,933	$1,664,000
Roadway Conduit 6"	84,000	$1,237	$103,900,000
Roadway Conduit 4" & 5"	4,500	$865	$3,892,000
Vacuum Switches	15	$164,867	$2,473,000
Cam-ops	15	$64,133	$962,000
		Sum =	$266,547,000

Project Risks and Mitigation Plan
Risk 1:
The project is likely to require multiple permits from various New York City agencies, permit processes could lead to delays. In addition, existing New York City, MTA, and LIRR infrastructure along planned routes needs to be identified and could lead to design changes or modifications, which could also result in project delays.

Mitigation Plan 1:
Identify issues early via surveys and engage stakeholders to get permits and find clear lanes.

Risk 2:
Interference with city contractors/paving coordination.

Mitigation Plan 2:
Coordinate with New York City agenencis including NYCDOT to get access and schedule work to avoid conflicts.

Risk 3:
Crossing major roadways and parks will require coordination and special design consideration with responsible government agencies.

Mitigation Plan 3:
Avoid crossings by rerouting. If not possible engage stakeholders early to plan alternative construction techniques, such as boring to cross major roadways, train lanes and park if possible. Evaluate Area Station siting and feeder routing considerations to avoid difficult crossings.

Risk 4:
Delays due resource/support coordination. There are a large number of projects to expand the electric distribution system that may strain existing resources.

Mitigation plan 4:
Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts. Expand hiring and increase the staffing to appropriate levels to support the increased work scale.

Risk 5:
Material availability issues.

Mitigation plan 5:
Engineering will work with Supply Chain to establish a cohesive plan that aligns with vendor lead times. Stay engaged with vendors to ensure lead times are maintained, and adjust the plan as needed if shortages are encountered.

Risk 6:
One major risk is that load increases faster than forecasted which will cause load to exceed equipment ratings before completion of projects to de-load such equipment.

Mitigation Plan 6:
Start projects early and on a longer cycle to allow for acceleration if the need arises.

Technical Evaluation / Analysis
N/A

Project Relationships (if applicable)
This project is dependent on the establishment of the Gateway Park No. 1 Area Station (planned to be in service by 2028), a new indoor 27kV area substation that will be arranged in a double SYN bus configuration with five 138/27kV transformer banks. The station will be supplied from the 345kV Brooklyn Energy Hub.

3. Funding Detail ($000)

Historic Spend

	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Test Year* (O&M Only)	Forecast 2024
O&M	$0	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	N/A	$0
Capital	$0	$0	$0	$0	N/A	$0

2025-2029 Request:

Total Request by Year:

	2025	2026 (RY1)	2027 (RY2)	2028 (RY3)	2029
O&M	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	$0
Capital (Total)	$0	$29,600	$71,000	$72,500	$71,000
Labor	$0	$3,837	$1,360	$3,400	$9,204
M&S	$0	$7,858	$15,913	$22,389	$18,849
Contract Svcs.	$0	$10,561	$28,661	$21,245	$25,549
Other	$0	$1,647	$0	$0	$3,951
Overheads	$0	$5,607	$25,076	$25,504	$13,448

*The test year runs from 10/1/2023 to 9/30/2024

Electric Operations / Distribution Engineering
2025-2029

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Brownsville Area Load Relief - Brownsville No. 1 to Glendale Transfer	
Project/Program Manager: Frantz St. Phar	**Project/Program Number (Level 1):** 25966356
Status: ☐ **Initiation/Planning** ☒ **In-Progress (Projects Only)** ☐ **On-going (Programs Only)**	
Estimated Start Date: 2022	**Estimated Date In Service:** 2026
2025-2029 Funding Request ($000) **Capital:** $63,000 **O&M:** $0	

Work Description:
This project is part of a Company program designed to alleviate forecasted overloads on the 138 kV feeders supplying the Brownsville No. 1 and No. 2 Area Substations. The Company first identified the need for a new substation to provide relief for the Brownsville substation in 2014, but prior load forecasts showed Brooklyn Queens Demand Management (BQDM) deferring the need for the new station until 2032. More recent forecasts, however, show significant, near-term load growth in the area (including adoption of electric vehicles and electric heating) necessitating a new station by 2028.

To mitigate risks of subsequent load growth and associated reliability issues before the long-term solution is implemented, the Company's planned program includes progressive solutions starting in 2024, and a long-term solution to be implemented by 2028.

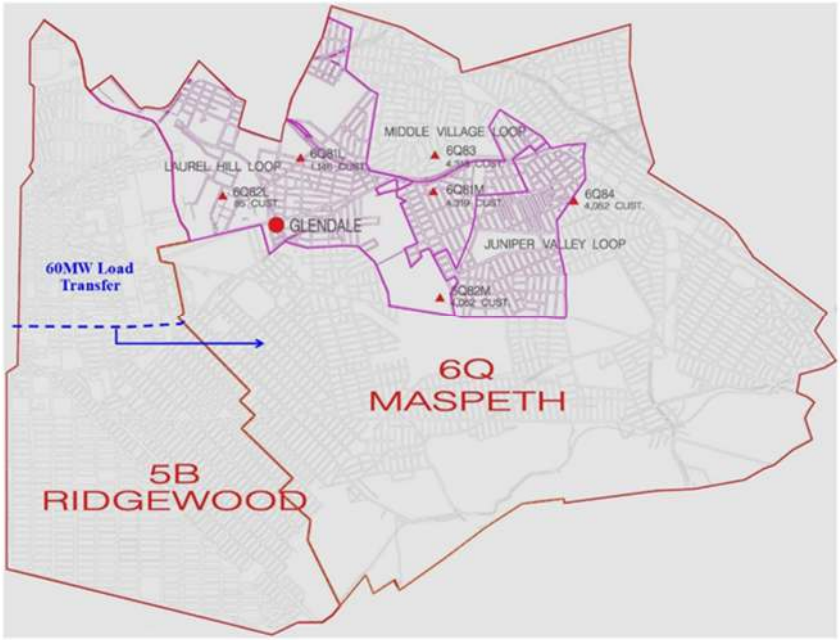
Progressive solutions identified to address Brownsville Area Station related feeder overloads include:

- 2024-2025: Operate the Farragut to Brownsville 138 kV feeders at 143 kV and 0.97 Power Factor
- 2024-2033: Install/maintain alternate utility and customer sided solutions for Brooklyn Queens Demand Management
- 2024: Transfer Metropolitan Transportation Authority (MTA) transit rectifier station (HTV7051) from Crown Heights (3B) to Flatbush (4B), reducing Brownsville feeder load by approximately 2 MW. (completed)
- 2025: Transfer MTA transit rectifier station (HTV-2337) and Starr 4 kV Autoloop from Ridgewood (5B) to Maspeth (6Q), reducing feeder load by approximately 4 MW.
- 2026: Install a fourth transformer at Newtown and a new 138kV sub-transmission feeder (38Q05) from the Vernon substation to the Newtown Area Substation (making capacity available on the 138 kV Vernon sub-transmission feeders supplying Glendale, Newtown & Amtrak) and transfer 60 MW from Brownsville No. 1 to Glendale.

The long-term solution to providing Brownsville load relief under this program is to construct the new Gateway Park Area Substation, to be supplied by the new Brooklyn Clean Energy Hub (BCEH) via four new 138kV sub-transmission feeders. The capital projects involved in completing the Gateway Park Area Substation and alleviating forecasted Brownsville overloads include:

- 2028: Establish Gateway Park Area Substation No. 1
- 2028: Split Crown Heights network and transfer 120 MW from Brownsville No. 1 to Gateway Park No. 1

This project is part of the progressive solution at the Brownsville Area Substations, providing transitional load relief at Brownsville No. 1 and No. 2 in 2026, before the long-term solution is implemented in 2028. To implement this progressive solution, the Company will install a new 138kV sub-transmission feeder (38Q05) from Vernon Substation to Newtown Area Substation along with a fourth 138kV/27kV transformer at Newtown Area Substation. Newtown Area Substation is currently supplied by three 138kV feeders that also originate from the Vernon Substation, and these three feeders (38Q02, 38Q03 and 38Q04/Q04T) also supply, along with Feeder 38Q01 from Vernon Substation, the Glendale Area Substation. The addition of Feeder 38Q05 to supply Newtown Area Substation increases the available capacity on Feeders 38Q01-38Q04. This increased capacity on the 138 kV sub-transmission feeders from Vernon Substation allows the Glendale Area Substation to accept a 60 MW network transfer from Brownsville No. 1, to provide load relief for the latter. (Coincidentally, load constraints are also forecasted for the Newtown Area Substation during the 10-year Load Relief Plan (LRP) period, and installation of this equipment will alleviate those constraints as well.)
Then, the Company will transfer approximately 60 MW from Brownsville No.1 Substation to Glendale Area Substation. The northern portion of the Ridgewood (5B) network was selected as the most viable option to transfer the 60 MW because of its geographic location. The design involves extending twelve network feeders from the Maspeth to the Ridgewood network. Fifteen feeders in the Ridgewood network will be split to accommodate the transfer.



The major scopes of work to be completed as part of this project include:

- Install 72,000 trench feet of conduit
- Install 819 sections of primary cable
- Install 189 sections of secondary cable
- Install 15 transformers
- Install or enlarge 71 manholes

- Install 15 vaults
- Install 29 switches

Engineering and long lead equipment procurement began in 2023 for this project and station construction is expected to begin in early 2025. Major or long lead equipment requirements for the project include, but are not limited to:

Major Equipment Type	Number to be Purchased
120/208V Transformer	15
Secondary Mains (sections, 250-ft each)	189
Street Ties (4 sets of 4-500)	11
3-2/0 EPR (splicing included) (sections, 250-ft each)	31
3-500 EPR (splicing included) (sections, 250-ft each)	729
3-750 EPR (splicing included) (sections, 250-ft each)	59
Vacuum Switches	13
Interrupter Switches	16
V13-6	15
M14	16
M11-6	52
Service Box	37
Roadway Conduit 4" & 5" (LF)	72,000
Cam-ops	45

Work began on this project in 2023 and is to be completed in 2026. The estimated timeline to complete this project is below. This timeline is subject to change at any time, as the Company optimizes the project schedule and incorporates impacts of other projects and system performance.

60MW 5B-6Q Cutover
Project Timeline / High-level Work Plan

Project Work Stream / Scope:	2022				2023				2024				2025				2026			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Engineering Design																				
Civil/Electrical Construction																				
Transfer Load / Establish New Network																				
Post-Intermesh Cleanup																				

Justification Summary:
The potential for the capability of the feeders supplying the Brownsville Area Substations to be exceeded by load growth was first identified in 2014 and has been confirmed by subsequent updates to Company's Area Substation and Sub-transmission Feeder Ten-Year Load Relief Program (the LRP) - i.e., the study that identifies equipment on the T&D system that are at risk of overload from load growth on the system. The LRP is updated annually in the Spring using the latest load forecast from the previous November. The 2024-2033 Load Relief Plan (2024 LRP) was finalized at the end of May 2024. Like prior LRPs, it identified a risk that the capability of the 138kV sub-transmission feeders supplying the Brownsville Area Substations could be exceeded during peak loading times.

Based on the current forecast, the Brownsville No. 1 and No. 2 supplied electric distribution networks (Crown Heights-3B, Ridgewood-5B, Richmond Hill-9B, and radial feeders 9B91-9B94) have projected loads that will cause the transmission feeders supplying the Brownsville load pocket (feeders: 38B01, 38B02, 38B03, 38B04 and 38B05) to exceed their capability as early as 2024. While progressive solutions can address sustained load growth in the near-term, a longer-term solution is needed in 2028.

The 2024 LRP projects that forecasted load growth will cause the capability of the feeders to the Brownsville Area Substations to be exceeded beginning in 2024 if the Company takes no action.

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Brownsville Nos. 1 & 2 Load - *No Action Taken* (adjusted for feeder peak diversity)	**804**	**822**	**843**	**859**	**870**	**883**	**917**	**939**	**964**	**993**
138 kV Feeder Capability	771	771	771	771	771	771	771	771	771	771
Exceedances if No Action Taken (i.e., amount that load exceeds capability)	33	51	72	88	99	112	146	168	193	222
Feeder Loading (%)	104%	107%	109%	111%	113%	115%	119%	122%	125%	129%

With future forecast load projected to impact Area Substations during this period, the Company must take additional steps in the near term to address the load issues in the first few years while pursuing other strategies that provide more long-term load relief. Progressive plans implementation in 2024-2026 are a combination of traditional utility-side and customer-side solutions, complemented with several manageable sized load transfers.

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Brownsville Nos. 1 & 2 Load - *No Action Taken* (adjusted for feeder peak diversity)	**804**	**822**	**843**	**859**	**870**	**883**	**917**	**939**	**964**	**993**
Interim Load Transfers:										
Crown Heights to Bensonhurst No. 2 (2024)	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
Crown Heights to Bensonhurst No. 2 (2025)	0	-5	-5	-5	-5	-5	-5	-5	-5	-5
Ridgewood to Glendale (2026)	0	0	-61	-62	-63	-64	-66	-68	-72	-74
	-1	**-6**	**-67**	**-68**	**-69**	**-70**	**-72**	**-74**	**-78**	**-80**
Brownsville Nos. 1 & 2 Load *Net of Interim* Load Transfers	**803**	**816**	**776**	**791**	**801**	**813**	**845**	**865**	**886**	**913**
Other Interim Measures										
Utility Sided Solutions	-11	-11	-11	-11	-10	-10	-10	-10	-11	-11
Customer Sided Solutions	-1	-1	-11	-11	-11	-11	-11	-11	-11	-11
	-12	**-12**	**-22**	**-22**	**-21**	**-21**	**-21**	**-21**	**-22**	**-22**
Brownsville Nos. 1 & 2 Load *Net of All Interim* Measures	**791**	**804**	**754**	**769**	**780**	**792**	**824**	**844**	**864**	**891**

As a practical operational measure, the Company is able to operate the Brownsville sub-transmission feeders at 143 kV in 2024 and 2025 to raise capability.

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
138 kV Feeder Capability	771	771	771	771	771	771	771	771	771	771
Feeder Capability @ 143kV and 0.97 CF	807	807								
Feeder Capability	**807**	**807**	**771**	**771**	**771**	**771**	**771**	**771**	**771**	**771**

Altogether, these progressive plans provide approximately 49 to 92 MW of load relief on the Brownsville feeders over the 10-year forecast period. These measures do not, however, provide adequate load relief after the initial years, making it obvious that the Company can no longer defer construction of a new substation in the area. Construction of the Gateway Park No. 1 Area Station and the split of the Crown Heights network and transfer 120 MW from Brownsville No. 1 to Gateway – the long-term solution under this program – fully alleviates forecasted constraints on the Brownsville feeders.

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Exceedances *with* Interim Measures and Alternative Feeder operations but *without* Load Transfer to Gateway Park No. 1	-16	-3	-17	-2	9	21	53	73	93	120
Load Transfer from Crown Heights to Gateway Park No. 1	0	0	0	0	-123	-123	-126	-128	-131	-133
Exceedances *with* Load Transfer to Gateway Park No. 1	-16	-3	-17	-2	-114	-102	-73	-55	-38	-13

The Gateway Park Area Substation project will improve network reliability by reducing network sizes and establishing feasible resiliency options for various contingency events, which are not available with the existing distribution system design. The affected networks are: *(1)* Crown Heights (3B) network fed from Brownsville No. 1, *(2)* Ridgewood (5B) network fed from Brownsville No. 1, *(3)* Flatbush (4B) network fed from Bensonhurst 2 (BH2), and *(4)* Richmond Hill (9B) fed from Brownsville No. 2.

Relationship to Broader Company Plans, Initiatives and the NYS Climate Leadership and Community Protection Act

The operational measures and system improvements implemented with this project sufficient addresses load growth across the Company's networks in central Brooklyn. By enabling load splits and smaller networks in the Brownsville and Bensonhurst load areas, this program will progressively increase the reliability of the associated networks in both the near and long term. It will help the Company avoid public safety issues related to network failure, customer outages and significant damage to company equipment. Also, it will protect customers from any issues related to network shutdown.

Resiliency plans: this program will help during problems in the transmission system and/or substation that result in limited load capacity in the Bensonhurst and Brownsville substations. Once this project is complete, the Company can feasibly transfer out or partially restore the load coming out of Bensonhurst and Brownsville and help minimize the outage impact to customers.

This project is a core investment that enables the Company to continue to provide safe and reliable service, even as the nature of the grid changes. This aligns with Con Edison's strategic objective of providing world-class safety, reliability, and security, while managing the equity challenges of the energy transition.

This project supports the State's achievement of CLCPA and clean energy goals. This aligns with Con Edison's strategic objective to meet economy-wide net-zero GHG emissions in our service territories by 2050.

This project is a climate resilience investment that strengthens utility infrastructure to withstand extreme weather conditions and the physical impacts of climate change. This aligns with Con Edison's strategic objective to increase resilience of our energy infrastructure to adapt to climate change and address other threats and hazards.

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection

One alternative was relying on Customer-Sided Solutions (CSS), such as energy efficiency programs, to mitigate future transmission capacity deficiencies. These programs can provide cost-effective solutions across various customer segments by accelerating load relief through energy-efficient upgrades and have helped to defer the need for traditional solutions for several years. However, given the significant load relief required to address the overload constraints in Brooklyn within a limited timeframe, the energy efficiency program is not a viable option. There is no known contingency plan other than to

pursue the identified traditional solution if this alternative is pursued and fails to meet the projected deficits.

Alternative 2 description and reason for rejection
Also considered was a plan for a different, traditional solution to the transmission capacity deficiencies associated with Bensonhurst Area Substations No. 1 and No. 2 and Brownsville Area Substations No. 1 and No. 2. Installing cable cooling plants for the feeders that supply Bensonhurst or Brownsville would increase their capacities and address the deficiencies. But this alternative would likely require land procurement for the cooling plants and only solve the feeder rating deficiency, without providing any network reliability improvements to the subject networks. Should load growth lead to the Bensonhurst and/or Brownsville substations reaching maximum capacity, additional work would be required.

Risk of No Action
Risk 1
An overload on the transmission feeders supplying Brownsville No.1 and No.2 Substations is predicted to occur. Many of the Company's Brooklyn/ Queens substations are near full capacity and do not offer the feasibility of load transfer. In the event the transmission feeders become overloaded, load shedding may be required during peak conditions with service dropped to thousands of customers.

Risk 2
If this project is not pursued, the NRI of the Ridgewood network will be negatively impacted when continued growth and the inability to either split the network or increase feeders result in an increasing NRI.

Additionally, constructing a new substation in Brooklyn only when it becomes necessary does not allow enough time to secure appropriately zoned land at a minimal cost. The Company risks having to acquire land through eminent domain or in a location that increases construction costs due to longer transmission and distribution circuits.

Non-Financial Benefits
Alleviating projected load constraints on the Brownsville feeders will enhance reliability and resiliency in a densely populated area of New York City that serves many critical loads, including buildings with elevators. This will also allow the station to maintain the N-1 reliability design criteria for long-term projected load growth in Brooklyn.

Splitting the load in Crown Heights and establishing a new network will improve the reliability of the 3B network, reduce customer outages, and potentially avoid the high costs associated with significant network or substation events. The new feeder cubicles vacated at Brownsville No. 1 can then be used to establish new feeders in Ridgewood, reducing the load per feeder. Additionally, it will be possible to transfer load from the southern portion of the Ridgewood network into the new 3B North network, further enhancing the reliability of the Ridgewood network.

The increased capacity provided by Gateway Park Area Substation potentially minimizes customer impact during an area station event that limits station capacity. Resiliency options in this load pocket are not feasible without experiencing rolling blackouts or utilizing mobile generating stations, which take weeks to set up. By introducing new area station capacity and splitting existing networks into smaller load areas, we can handle the loss of station capacity during emergencies while minimizing customer impact. If capacity at Brownsville, Bensonhurst, or Gateway stations is compromised, load can be swapped between stations, minimizing or eliminating the need for load shedding during an event. The design for network splits will account for resiliency by accommodating load swaps during emergencies.

Meeting New York's Climate Leadership and Community Protection Act (CLCPA) goals will ultimately require the Company to build system capacity for the anticipated increase in load growth. As the City transitions from a carbon-based economy and electrification progresses, the system will need to accommodate unprecedented load growth in the affected networks. Rapid load growth has the potential to place the Company in a difficult position to address future relief and reliability issues.

Additionally, completing the necessary work to address load constraints at Brownsville will facilitate the completion of other projects that benefit customers, including:

Splitting Flatbush (4B) Network: The Bensonhurst load pocket will need load relief in the future. Fifteen new feeders will be extended west from Gateway to pick up the south portion of the 4B network. The south portion consists of mostly non-network 4kV load with a total of 127 MWs and fifteen feeders. Six feeder cubicles would be released by this project in Bensonhurst 2 and can be used for new feeders in the 4B network and/or Brighton Beach (11B) networks. This would de-load the Bensonhurst load pocket and improve the reliability of the networks fed by it. In addition, the new load pocket can be made transferrable between Gateway and Bensonhurst No. 2 to add an element of resiliency to the project.

Ridgewood (5B) Network: This network has the highest Network Reliability Index (NRI). With the construction of Gateway and the release of 3B South from BRO, three feeder cubicles will be made available in Brownsville No. 1, allowing new feeders to be introduced into the 5B network. Also, a portion of 5B south of Broadway can be permanently transferred to 3B North, further improving the NRI of Ridgewood. Resiliency can also improve if this load pocket out of Ridgewood is made transferable between Gateway and Brownsville No. 1.

Richmond Hill (9B) Network: This network can be split into two portions: 9B North and 9B South. This will greatly improve reliability by breaking the load into two smaller load pockets. The feeders from 3B South will be extended to and permanently pick up 9B South. This will reduce the load in the Brownsville load pocket and release four feeder cubicles in Brownsville No. 2 that can be used for new feeders in the 9B Network. 9B South can be made transferable between Gateway and Brownsville No. 2 to add an element of resiliency to the project.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)
N/A

2. Major financial benefits
This project will enable the Company to address potential transmission equipment overloads. Exceeding the capacity of the substation and transmission feeders may require load shedding if contingencies occur during peak loading conditions, resulting in customer outages and increasing the risk of equipment failure and adverse impacts to the community served. The regulatory financial costs of load shedding customers and the cost of replacing transmission/station equipment can be significant to the Company. This project will mitigate the risk of incurring those costs.

3. Basis for estimate
Unit costing method was used. We estimated the number of required units of equipment and material and multiplied by a loaded unit cost that contains material, labor and overheads.

When this project was initially proposed, the estimated cost was $88.5 million based on a high-level estimate of a conceptual scope. Since the initial proposal of this project in the previous rate case, Con Edison has refined plans for executing this load transfer and refined the scope of work needed. The estimated project cost for the refined scope of work is $119 million.

Activity	Units	Unit Cost	Total Cost
120/208V Transformer	15	19,867	$ 298,000
Cut & Rack Structure	50	37,360	$ 1,868,000
Secondary Mains (sections, 250-ft each)	189	20,206	$ 3,819,000
Street Ties (4 sets of 4-500)	11	7,273	$ 80,000
3-2/0 EPR (splicing included) (sections, 250-ft each)	31	39,677	$ 1,230,000
3-500 EPR (splicing included) (sections, 250-ft each)	729	51,457	$ 37,512,000
3-750 EPR (splicing included) (sections, 250-ft each)	59	67,475	$ 3,981,000
3-1000 EPR (splicing included) (sections, 250-ft each)	-	-	$ -
Vacuum Switches	13	139,308	$ 1,811,000
Interrupter Switches	16	419,188	$ 6,707,000
V13-6	15	93,733	$ 1,406,000
M14	16	92,250	$ 1,476,000
M11-6	52	45,135	$ 2,347,000
MH Enlargement	3	305,333	$ 916,000
Service Box	37	14,081	$ 521,000
Roadway Conduit 4" & 5" (LF)	72,000	731	$ 52,631,000
Cam-ops	45	54,222	$ 2,440,000
		Total Estimated Cost	**$ 119,043,000**

Project Risks and Mitigation Plan

Risk 1:
Permitting by the city, Park departments, MTA & LIRR Interference, find lanes for ducts to be installed.

Mitigation Plan 1:
Identify issues early via surveys and engage stakeholders to get permits and find clear lanes.

Risk 2:
Interference with city contractors/paving coordination.

Mitigation Plan 2:
Coordinate with city and DOT to get access and schedule work to avoid conflicts.

Risk 3:
Crossing major roadways and parks.

Mitigation Plan 3:
Avoid crossings by rerouting. If not possible engage early to find different construction techniques like boring to cross major roadways, train lanes and park if possible.

Risk 4:
Delays due resource/support coordination. There are a large number of projects to expand the electric distribution system that may strain existing resources.

Mitigation Plan 4:
Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Risk 5:
Material Availability Issues.

Mitigation Plan 5:
Engineering will work with Supply Chain to establish a cohesive plan that aligns with vendor lead times. Stay engaged with vendors to ensure lead times are maintained, and adjust the plan as needed if shortages are encountered.

Technical Evaluation / Analysis
In general, infrastructure adequacy is determined by comparing the infrastructure capability, in this case the transmission system supplying the Brownsville load pocket, against the net load to be served. The net load is determined from the gross forecasted customer demand less any load relief measures such as existing and forecasted energy efficiency or local distributed resources in the network.

The capability of the transmission system and the forecasted demand for the Brownsville load pocket includes consideration of customer sided and utility sided solutions totaling 26 MWs. Capability of the 138 kV transmission system is based on using nominal operating voltage of 138 kV and Summer Normal feeder rating. Based on the demand forecast by 2028 and 138 kV feeder capabilities, the 138 kV transmission feeders were deficient, with deficiencies continuing to grow and will require load relief. Some temporary operating measures include increased short term feeder ratings and/or higher operating voltages, until permanent relief is obtained.

Project Relationships (if applicable)
This project is sequential and complimentary to the establishment of the Gateway Park Area Station by 2028, a new indoor 27kV area substation that will be arranged in a double SYN bus configuration and with five 138/27kV transformer banks. The station will be supplied from the 345kV Brooklyn Energy Hub.

3. Funding Detail ($000)

Historic Spend

	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Test Year (O&M Only)*	Forecast 2024
O&M	$0	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	N/A	$0
Capital	$0	$0	$0	$19,922	N/A	$41,000

2025-2029 Request:
Total Request by Year:

	2025	2026 (RY1)	2027 (RY2)	2028 (RY3)	2029
O&M	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	$0
Capital (Total)	$51,000	$12,000	$0	$0	$0
Labor	$10,872	$2,693	$0	$0	$0
M&S	$10,163	$2,351	$0	$0	$0
Contract Svcs.	$10,494	$2,473	$0	$0	$0

Other	$990	$213	$0	$0	$0
Overheads	$18,481	$4,271	$0	$0	$0

*The test year runs from 10/1/23 to 9/30/24.

Electric Operations / Distribution Engineering
2025-2029

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Ossining West to Millwood West Transfer	
Project/Program Manager: Kevin Oehlmann	**Project/Program Number (Level 1):** 28016992
Status: ☒ **Initiation/Planning** ☐ **In-Progress (Projects Only)** ☐ **On-going (Programs Only)**	
Estimated Start Date: 2026	**Estimated Date In Service:** 2030
2025-2029 Funding Request ($000) **Capital:** $8,300 **O&M:** $0	

Work Description:
Based on the 2025-2034 Area Substations and Sub-transmission Feeders Ten-Year Relief program, the Ossining West Area Substation requires a load transfer in 2030 to mitigate risk. As a result, a proposed load transfer of 20 MW from Ossining West to Millwood West Area Substation.

Major Scopes of Work:
- Installation of new conduit systems, including civil works to cross highway and overpasses within the load area footprint.
- Installation of new underground (UG) and overhead (OH) aerial cables to connect the newly established feeders.
- Installation of new underground and overhead structures to support the additional feeder infrastructure.
- Coordination with external engineering consultants for the design and permitting of conduit systems, particularly for complex crossings.

Major or Long Lead Equipment Requirements:
- **Conduit Systems:** Procuring non-class and stock material to construct the necessary infrastructure that will house cables to transverse barriers such as highways and overpasses.
- **Underground Structures:** Procuring standard structural housing where underground feeder cables will be spliced to support the feeder network expansion.
- **Overhead Structures:** Procuring overhead fixtures which are storm hardened for northeast environmental conditions that will facilitate the installation of aerial feeder cables to support the feeder network expansion.
- **Underground and Aerial Cables:** Installation in multiple sections.

To accomplish the required transfer of load, engineering designs and planning will be completed in advance. The planning and designing for installing cables across highways in Westchester County is a critical path. If needed, Con Edison will retain engineering consulting services to complete initial and detailed designs for civil construction on highway overpasses. Prior to performing civil construction at highway crossings, DOT coordination and approval are required, taking an average of approximately two years.

Justification Summary:

Based on forecasted load growth for Ossining West Area Substation, the 138 kV feeders that feed the station will surpass their ratings in 2030.

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Ossining West	72	76	79	81	81	82	83	84	84	85	86	86	87	87	88	88	89	89	90	90
Electrification Adjustment	1	3	5	7	9	11	14	16	18	20	22	24	25	26	28	29	30	30	30	30
Other Adjustments	-2	-3	-4	-5	-5	-4	-5	-5	-5	-5	-5	-6	-6	-6	-7	-8	-9	-9	-9	-10
Net Load	71	76	80	83	85	89	92	95	97	100	103	104	106	107	109	109	110	110	111	110
Capability	89																			
Low Voltage Capability (1)	107																			
1-Hour Capability	100																			
Ossining West Load	71	76	80	83	85	89	92	95	97	100	103	104	106	107	109	109	110	110	111	110
Capability	86																			
Capability LTE	93																			
138 kV Feeder Loading	83%	88%	93%	97%	99%	103%	107%	110%	113%	108%	111%	112%	123%	124%	127%	127%	128%	128%	129%	128%

Transferring approximately 20 MW of load from Ossining West to Millwood West alleviates these forecasted overloads.

The load transfer is critical to the continuation of providing reliable electric service to our customers as the demand for electricity continues to grow through electrification and incremental load growth. This project will result in Ossining West Substation operating within its capability limits and maintaining capacity for future load growth.

Relationship to Broader Company Plans, Initiatives and the NYS Climate Leadership and Community Protection Act

This project will not directly impact greenhouse gas emissions.

This project strengthens the Con Edison electric system in the areas served by these facilities, including service to disadvantaged communities.

This project is a core investment that enables the Company to continue to provide safe and reliable service, even as the nature of the grid changes. This aligns with Con Edison's strategic objective of providing world-class safety, reliability, and security, while managing the equity challenges of the energy transition.

This project supports the State's achievement of CLCPA and clean energy goals. This aligns with Con Edison's strategic objective to meet economy-wide net-zero GHG emissions in our service territories by 2050.

This project is a climate resilience investment that strengthens utility infrastructure to withstand extreme weather conditions and the physical impacts of climate change. This aligns with Con Edison's strategic objective to increase resilience of our energy infrastructure to adapt to climate change and address other threats and hazards.

2. Supplemental Information

Alternatives

One alternative would be to delay the load transfer. However, given the long permitting and lead times associated with this work this course of action would likely result in the Ossining West Area Substation exceeding its load capability in 2035.

Another alternative is to set up and run mobile generators in this area during peak load periods; however, diesel generators pose an environmental hazard and do not support the Company's goals of delivering clean reliable energy to its customers.

Risk of No Action
Without any action, the source feeders for Ossining West Area Substation are projected to exceed their ratings in 2030. The area station is projected to exceed its load capability in 2035.

Non-Financial Benefits
Pursing the Ossining West to Millwood West Load Transfer project will allow the state of New York to stay on track on satisfying its environmental commitment (CLCPA) which ultimately benefits the ratepayers of the southern Westchester with access to reliable energy for electrification of heat and vehicles. Additionally, the project will support future economic growth in the area by ensuring that the electrical infrastructure can accommodate increased demand without compromising reliability.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis (if required)
N/A

2. Major financial benefits
N/A

3. Basis for estimate
The estimated costs are based on the cost for similar types of work accomplished as part of previous projects. The specific initial estimate for the work is outlined below.

		2026	2027	2028	2029	2030			
Project	**Activities**	**Units**	**Units**	**Units**	**Units**	**Units**	**Total**	**Unit Cost**	**Total Cost**
Ossining 20 MW transfer to Millwood	Engineering Consultant	*	*						$ 4,500,000
	Install Conduit		9284	8,515	8,515		26,314	$ 847	$ 22,287,958
	Install UG Structures		31	22	21		74	$ 68,932	$ 5,100,968
	Install UG Cable			43	43		86	$ 52,455	$ 4,511,130
	Install Aerial Cable			188	188		376	$ 18,273	$ 6,870,648
	Install Poles			191	190		381	$ 17,071	$ 6,504,051
									$ 49,774,755

*Funding in 2026 and 2027 will be used to complete the designs needed for highway and railroad crossings.

Project Risks and Mitigation Plan
Risk 1: The potential risks that exist for the project are insufficient resources regarding labor, delays with material due to supply chain issues, and escalating cost.

Mitigation Plan 1: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts. In addition, to explore an alternative mutually beneficial contract structure for the anticipated civil work and ordering equipment in advance of lead time to hedge against rising commodity cost.

Technical Evaluation / Analysis
N/A

Project Relationships (if applicable)
This project requires the completion of the Millwood West Install Third Transformer with its 138 kV Supply Feeder project to be executed by SSO.

3. Funding Detail ($000)

Historic Spend

	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Test Year* (O&M Only)	Forecast 2024
O&M	$0	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	N/A	$0
Capital	$0	$0	$0	$0	N/A	$0

2025-2029 Request:
Total Request by Year:

	2025	2026 (RY1)	2027 (RY2)	2028 (RY3)	2029
O&M	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	$0
Capital (Total)	$0	$3,000	$11,500	$16,200	$17,600
Labor	$0	$389	$1,491	$2,100	$2,281
M&S	$0	$796	$3,053	$4,301	$4,673
Contract Svcs.	$0	$1,080	$4,138	$5,829	$6,333
Other	$0	$167	$640	$901	$997
Overheads	$0	$568	$2,178	$3,068	$3,333

*The test year runs from 10/1/2023 to 9/30/2024

Electric Operations / Distribution Engineering
2025-2029

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Washington Street to Cedar Street Transfer	
Project/Program Manager: Frantz St. Phar	**Project/Program Number (Level 1):** 27725414
Status: ☒ **Initiation/Planning** ☐ **In-Progress (Projects Only)** ☐ **On-going (Programs Only)**	
Estimated Start Date: 2026	**Estimated Date In Service:** 2031
2025-2029 Funding Request ($000) **Capital:** $89,302 **O&M:** $0	

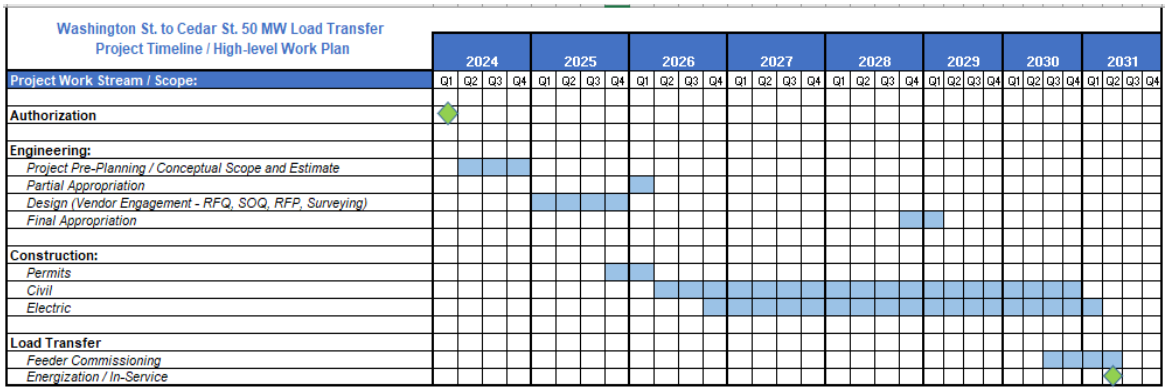
Work Description:
Based on the Company's latest 2024 Forecast, the Washington St. Area Substation requires a load transfer in 2031 to mitigate risk. As a result, a proposed load transfer of approximately 50 MW will be transferred from Washington St. to Cedar St. Area Substation.

Major Scopes of Work:
- Installation of new conduit systems, including civil works to cross multiple highways and overpasses within the network footprint.
- Installation of new underground (UG) and overhead (OH) aerial cables to connect the newly established feeders.
- Installation of new underground and overhead structures to support the additional feeder infrastructure.
- Coordination with external engineering consultants for the design and permitting of conduit systems, particularly for complex crossings.

Major or Long Lead Equipment Requirements:
- **Conduit Systems:** Procuring non-class and stock material to construct the necessary infrastructure that will house cables to transverse barriers such as highways and overpasses.
- **Underground Structures:** Procuring standard structural housing where underground feeder cables will be spliced to support the feeder network expansion.
- **Overhead Structures:** Procuring overhead fixtures which are storm hardened for northeast environmental conditions that will facilitate the installation of aerial feeder cables to support the feeder network expansion.
- **Underground and Aerial Cables:** Installation in multiple sections.

To accomplish the transfer of load in a timely manner, all engineering designs and planning are to be completed in advance. The planning and designing for installing cables across overpasses due to multiple highways in Westchester County is crucial. These overpasses are the only routes to bring new feeders from Cedar St. area substation to the Washington Street load area. Con Edison will have to retain engineering consulting services to complete initial and detailed designs for civil construction on

the overpasses. Prior to performing civil construction on the overpasses, DOT coordination and approval are required, taking an average of approximately two years.



Justification Summary:

Previously, Con Edison utilized purely deterministic processes to assess load relief need. This process resulted in "just-in-time" project completion as the year the energy forecast's projected demand approaches a substation's capability. Forecast uncertainty due to the dynamic energy landscape driven by the Climate Leadership and Community Protection Act (CLCPA) and NY state policies have required the Company to adapt the existing planning process to capture other elements of risk. For this reason, the Company has elected to incorporate a probabilistic method of planning where risk of customer interruption is modeled to prioritize substation work in the riskiest stations and maintain system reliability.

Based on forecasted load growth for Washington Street Area Substation, the station would have its capability surpassed in 2032. With "just-in-time" planning, temporary emergency load transfers (1-Hour Capability) would be utilized from 2032 to 2033. In 2034, when forecasted load exceeds the 1-Hour Capability, an approximate 50 MW load transfer is required to provide load relief. However, probabilistic assessment identified Washington Street Area Substation to have an elevated risk of customer interruption as it approaches its substation capability. For this reason, the project timeline has been risk adjusted at Washington Street Area Substation from 2034 to 2031.

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Washington Street (w/o transfer)	197	199	202	204	205	206	207	207	208	208	209	209	210	210	211	211	212	212	213	213
Electrification Adjustment	2	6	9	12	16	21	26	31	36	41	46	51	56	60	64	69	72	76	79	82
Other Adjustments	-2	-3	-4	-4	-3	-1	-1	0	0	0	0	0	0	0	1	0	0	0	-1	-1
Net Load	197	202	207	212	218	226	232	238	244	249	255	260	266	270	276	280	284	288	291	294
Capability	231																			
Net Load as % of current Capability	85%	87%	90%	92%	94%	98%	100%	103%	106%	108%	110%	113%	115%	117%	119%	121%	123%	125%	126%	127%
1-Hour Capability								245	245	245	245	245	245	245	245	245	245	245	245	245
Net Load as current % of 1-Hour Capability								97%	100%	102%	104%	106%	109%	110%	113%	114%	116%	118%	119%	120%

Transferring approximately 50 MW of load from Washington St. to Cedar St. In 2031 alleviates this forecasted needs and elevated risk.

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Washington Street (w/ transfer)	197	199	202	204	205	206	162	162	163	163	164	164	164	164	165	165	166	166	167	167
Electrification Adjustment	2	6	9	12	16	21	20	24	28	32	36	40	44	47	50	54	56	59	62	64
Other Adjustments	-2	-3	-4	-4	-3	-1	0	0	0	0	0	0	0	0	1	0	0	0	-1	-1
Net Load	197	202	207	212	218	226	182	186	191	195	200	204	208	211	216	219	222	225	228	230
Capability	231																			
Net Load as % of current Capability	85%	87%	90%	92%	94%	98%	79%	81%	83%	84%	87%	88%	90%	91%	94%	95%	96%	97%	99%	100%

The load transfer is critical to the continuation of providing reliable electric service to our customers as the demand for electricity continues to grow through electrification and incremental load growth. This project will result in Washington St. Area Substation operating within its capability limits and maintaining capacity for future load growth.

Relationship to Broader Company Plans, Initiatives and the NYS Climate Leadership and Community Protection Act
This project will not directly impact greenhouse gas emissions.

This project strengthens the Con Edison electric system in the areas served by these facilities, including service to disadvantaged communities.

This project is a core investment that enables the Company to continue to provide safe and reliable service, even as the nature of the grid changes. This aligns with Con Edison's strategic objective of providing world-class safety, reliability, and security, while managing the equity challenges of the energy transition.

This project supports the State's achievement of CLCPA and clean energy goals. This aligns with Con Edison's strategic objective to meet economy-wide net-zero GHG emissions in our service territories by 2050.

This project is a climate resilience investment that strengthens utility infrastructure to withstand extreme weather conditions and the physical impacts of climate change. This aligns with Con Edison's strategic objective to increase resilience of our energy infrastructure to adapt to climate change and address other threats and hazards.

2. Supplemental Information

Alternatives
One alternative would be to delay the load transfer. However, given the long permitting and lead times associated with this work this course of action would likely result in the Washington St. Area Substation exceeding its load capability in 2034.

Another alternative is to set up and run mobile generators in this area during peak load periods; however, diesel generators pose an environmental hazard and do not support the Company's goals of delivering clean reliable energy to its customers.

Risk of No Action
Without any action, the Washington St. Area Substation is projected to exceed its load capability in 2034.

Non-Financial Benefits
Pursing the Washington Street to Cedar Street Load Transfer project will allow the state of New York to stay on track on satisfying its environmental commitment (CLCPA) which ultimately benefits the ratepayers of the southern Westchester with access to reliable energy for electrification of heat and vehicles. Additionally, the project will support future economic growth in the area by ensuring that the electrical infrastructure can accommodate increased demand without compromising reliability.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis (if required)
N/A

2. Major financial benefits
N/A

3. Basis for estimate
The estimated costs are based on the cost for similar types of work accomplished as part of previous projects. The specific initial estimate for the work is outlined below.

2026				
Activities	**Quantity**	**Unit of Measure**	**Unit Cost**	**Cost**
Engineering Consultant				$8,500,000
Install Conduit	15,900	Trench Feet	$847	$13,467,300
Install UG Cable	46	Section	$52,455	$2,412,930
Install UG Structures	48	Structure	$68,932	$3,308,736
Install Aerial Cable	116	Span	$18,273	$2,119,668
Install Poles	118	Pole	$17,071	$2,014,378
				$31,823,012

2027				
Activities	**Quantity**	**Unit of Measure**	**Unit Cost**	**Cost**
Install Conduit	26,500	Trench Feet	$847	$22,445,500
Install UG Cable	75	Section	$52,455	$3,934,125
Install UG Structures	80	Structure	$68,932	$5,514,560
Install Aerial Cable	154	Span	$18,273	$2,814,042
Install Poles	156	Pole	$17,071	$2,663,076
				$37,371,303

2028				
Activities	**Quantity**	**Unit of Measure**	**Unit Cost**	**Cost**
Install Aerial Cable	233	Span	$18,273	$4,257,609
Install Poles	234	Pole	$17,071	$3,994,614
				$8,252,223

2029				
Activities	**Quantity**	**Unit of Measure**	**Unit Cost**	**Cost**
Install Conduit	5,300	Trench Feet	$847	$4,489,100
Install UG Cable	15	Section	$52,455	$786,825
Install UG Structures	16	Structure	$68,932	$1,102,912

Install Aerial Cable	154	Span	$18,273	$2,814,042
Install Poles	156	Pole	$17,071	$2,663,076
				$11,855,955

2030				
Activities	**Quantity**	**Unit of Measure**	**Unit Cost**	**Cost**
Install Conduit	5,300	Trench Feet	$847	$4,489,100
Install UG Cable	9	Section	$52,455	$472,095
Install UG Structures	16	Structure	$68,932	$1,102,912
Install Aerial Cable	116	Span	$18,273	$2,119,668
Install Poles	118	Pole	$17,071	$2,014,378
				$10,198,153

2031				
Activities	**Quantity**	**Unit of Measure**	**Unit Cost**	**Cost**
Install UG Cable	6	Section	$52,455	$314,730
				$314,730

Project Total	**$99,815,376**

Project Risks and Mitigation Plan
Risk 1: The potential risks that exist for the project are insufficient resources regarding labor, delays with material due to supply chain issues, and escalating cost.

Mitigation Plan 1: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts. In addition, to explore an alternative mutually beneficial contract structure for the anticipated civil work and ordering equipment in advance of lead time to hedge against rising commodity cost.

Technical Evaluation / Analysis
N/A

Project Relationships (if applicable)
N/A

3. Funding Detail ($000)

Historic Spend

	Actual 2020	**Actual 2021**	**Actual 2022**	**Actual 2023**	**Test Year* (O&M Only)**	**Forecast 2024**
O&M	$0	$0	$0	$0	$0	$0

Regulatory Asset	$0	$0	$0	$0	N/A	$0
Capital	$0	$0	$0	$0	N/A	$0

2025-2029 Request:

Total Request by Year:

	2025	**2026 (RY1)**	**2027 (RY2)**	**2028 (RY3)**	**2029**
O&M	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	$0
Capital (Total)	$0	$31,823	$37,371	$8,252	$11,856
Labor	$0	$4,732	$5,557	$1,227	$1,763
M&S	$0	$6,195	$7,275	$1,606	$2,308
Contract Svcs.	$0	$8,934	$10,491	$2,317	$3,328
Other	$0	$318	$374	$83	$119
Overheads	$0	$11,644	$13,674	$3,019	$4,338

*The test year runs from 10/1/2023 to 9/30/2024

Electric Operations / Distribution Engineering

2025-2029

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Williamsburg Network Split - Water St to Nevins St Transfer	
Project/Program Manager: Frantz St. Phar	**Project/Program Number (Level 1):** 27708522
SStatus: ☒ **Initiation/Planning** ☐ **In-Progress (Projects Only)** ☐ **On-going (Programs Only)**	
Estimated Start Date: 2026	**Estimated Date In Service:** 2032
2025-2029 Funding Request ($000) **Capital:** $129,600 **O&M:** $0	

Work Description:
Con Edison is planning this project to de-load the Water Street Area Substation with the added benefit that this will also address the transmission restrictions of the 138KV system that feeds Water Street from the Farragut transmission switching station. Based on the Company's latest 2024 Forecast, both the Water Street Area Station and its Farragut 345/138 kV transmission supply transformers will exceed capability in 2032. Therefore, this project seeks to de-load both the Water Street Area Substation and the transmission equipment at Farragut Switching Station. The transmission constraints are caused by the Farragut X-Winding transformer which feeds Water Street.

The Williamsburg network (6B) served from the Water Street Area Substation is projected to have a net load of 345 MW in 2025, a 24-feeder network with approximately 123,000 electric customers. Con Edison is planning to de-load the Water Street Area Substation by splitting the 6B network into two separate load areas: 6B North of Flushing Avenue to be supplied by Water Street and 6B South of Flushing Avenue supplied by the new Nevins station. The south side will be carved out by the area bounded by Flushing Avenue in the north, Fort Green Place in the west, Throop Avenue in the east and Atlantic Avenue in the south. This new carved out network "Fort Greene" will consist of 14 feeders and a net load of 149 MWs and supplied by Nevins St Area Substation in 2032. 6B north will be bounded by the East River in the west, Newtown creek in the north, Graham Avenue in the east and Flushing Avenue in the south. This smaller Williamsburg network will continue to be supplied by Water Street Area Substation. The new smaller Williamsburg network will be supplied by 18 feeders from Water Street substation and will supply 261 MW of load to the customers north of Flushing Ave. This 261 MWs of load is the forecasted load for 2032. These forecasted loads don't include electrification adjustments as the city transitions out of dependency on fossil fuels.

In order to supply the new 6B south network, Con Edison will extend 14 feeders from the newly established Nevins St Area Substation to the load area that will be segregated. The rest of the network north of Flushing Avenue will continue being supplied by Water Street. There are 14 feeders south of Flushing Avenue. However, 6 of the 14 supply both north and south of Flushing Avenue. Therefore, in addition to the 14 feeder extensions from Nevins, 6 bypass cables will be installed to allow for the continuity of the Water Street feeders that supply both north and south of Flushing Avenue to continue

supplying load only north of Flushing Avenue. This will allow the 6 feeders to only supply 6B north load.

Con Edison will be using 1000 mcm cable from Nevins to the pick-up points of 6B South to allow for future load growth. Figure 1 below show the way the new feeders will run to pick the load being dropped from the Williamsburg Network.

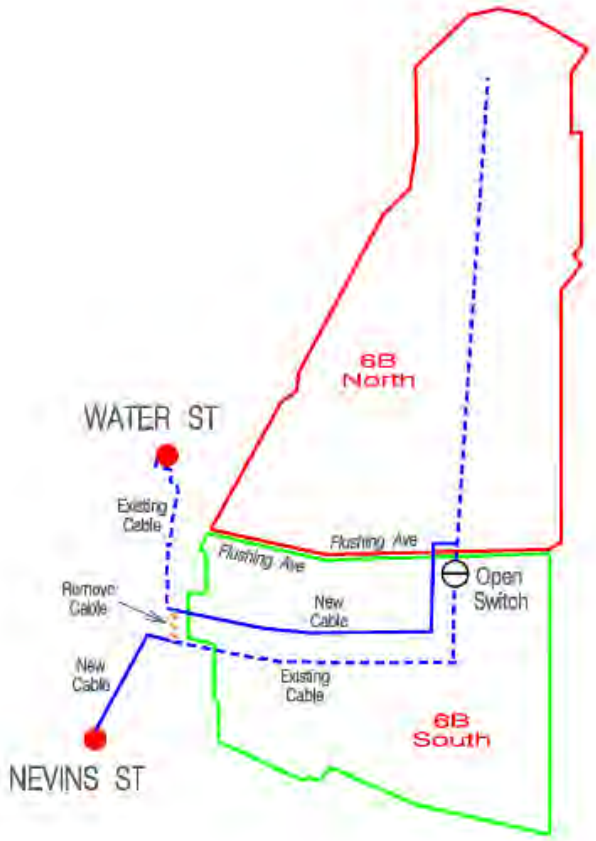


Figure 1. Overall feeder run from Nevins station to create a new network south of Flushing Avenue to supplied by the New Nevins Station.

A prerequisite to this work is the establishment of the Nevins Area station which is a separate project. This station is a new indoor 27kV area substation that will be arranged in a double SYN bus configuration with four 138kV/27kV transformer banks. The station will be supplied from the 345kV Brooklyn Energy Hub. This station will allow for added resiliency to the network and additional transmission capacity to mitigate deficiencies in the Farragut transmission switching station. The project splits the Williamsburg network by carving out 140 MW of network load in 2032 and creates a new 6B south network, Fort Greene. The property where Nevins St Area Substation will be built has been purchased and it is located on Nevins Street between Butler and Baltic Streets.

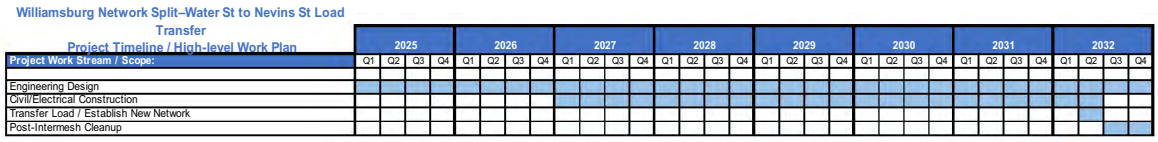
Major scopes of work to be completed to split the Williamsburg Network include:

- Installation of 89,000 feet of roadway conduit
- Installation of 655 sections of primary cable
- Installation of 300 sections of secondary main
- Installation of 334 manholes
- Installation of 20 120/208V transformers

Major or long lead equipment requirements for the project include, but are not limited to:

Major Equipment Type	Number to be Purchased
120/208V Transformer	20
Secondary Mains	300
Street Ties (4 sets of 4-500)	44
3-2/0 EPR (splicing included)	25
3-1000 EPR (splicing included)	630
M14	315
M11-6	19
Service Box	9
V13-6	18
Roadway Conduit 6"	77,000
Roadway Conduit 4" & 5"	12,000
Vacuum Switches	14
Cam-ops	14

Engineering will begin in 2026 for this project, construction is expected to begin in 2027 and to be completed in 2032. The estimated timeline to complete the major scopes of work associated with the project is below. This timeline is subject to change at any time, as the Company optimizes the project schedule and incorporates impacts of other projects and system performance.



Justification Summary:
Based on the Company's latest 2024 Forecast, Water Street Area Station and its supply Farragut transmission transformers require load relief in 2032. Probabilistic planning analysis on the Company's 2023 Forecast showed Water Street Area Station exposed to high risk of customer service interruption. As a result of this analysis, the project timeline was adjusted from the identified 2034 need date to 2033, which was superseded by the Company's latest 2024 forecast indicating a 2032 need for load relief.

Previously, Con Edison utilized purely deterministic processes to assess load relief needs. This process resulted in "just-in-time" project completion as the year the energy forecast's projected demand approaches a substation's capability. Forecast uncertainty due to the dynamic energy landscape driven by the Climate Leadership and Community Protection Act (CLCPA) and NY state policies have required the Company to adapt the existing planning process to capture other elements of risk. For this reason, the Company has elected to incorporate a probabilistic method of planning where the risk of customer interruption is modeled to prioritize substation work in the riskiest stations and maintain system reliability.

Deterministic analyses in the 2024 Load Relief Plan ("LRP") based on the 2023 load forecast projected that load growth would cause the capability of the Water Street Area Substation to be exceeded in 2034. Probabilistic risk assessment, however, identified an elevated risk of load drop at this station as the load served approaches its capability. As a result, the timeline for load relief in the 2024 LRP was

adjusted and the planned transfer of load from the Water Street Area Substation to the new Nevins Street Area Substation was moved from 2034 to 2033.

Analysis of the Company's latest load forecast from 2024, however, indicates that load relief would be needed at the Water Street Area Substation as early as 2032. In addition, the Farragut X-winding transmission transformers which supplies Water Street from the Farragut switching station will also overload in 2032. This project will also de-load transmission equipment. Due to the variability of the forecast, completing the distribution work early will protect the system from earlier than expected overloads in both the area station and the transmission equipment. Below, the Water Street Area Substation and supplying Farragut X-winding transformers loadings can be seen with the latest Company's 2024 Forecast:

Water Street	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Williamsburg	348	362	375	383	389	393	397	401	405	408
Prospect Park	68	69	70	71	72	73	73	74	74	74
Total Load	416	431	445	454	461	466	470	475	479	482
Electrification Adjustment	3	9	11	15	21	27	34	41	49	57
Other Adjustments	-6	-10	-12	-16	-16	-12	-14	-15	-16	-16
Net Load	413	430	444	453	466	481	490	501	512	523
Capability	497									
							overload	4	15	26
138 kV Feeder Capability	532									
138 kV Feeder Loading	78%	81%	83%	85%	88%	90%	92%	94%	96%	98%
									overload	
Farragut X-winding Load	293	310	324	333	346	361	370	381	392	403
Capability	373									
							overload	8	19	30
Farragut X-winding Loading	79%	83%	87%	89%	93%	97%	99%	102%	105%	108%
[TR5 S.E. 300-Hr Rating = 552 Amps]										

Resulting load transfer from Water Street to Nevins Street supplying the Fort Greene network beginning in 2032 are as follows:

	2025	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Nevins St										
Fort Greene								140	141	142
Electrification Adjustment								13	16	19
Other Adjustments								-4	-5	-5
Net Load								149	152	156
Capability								358		

The planned Williamsburg network split of approximately 140 MW's in 2032 will result in a transfer of 149 MWs of net load to establish the new Fort Greene network supplied by Nevins Street Area Substation, and result in a smaller Williamsburg network of 261 MW in 2032 to be supplied by the Water Street Area Substation.

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Water Street										
Williamsburg	348	362	375	383	389	393	397	261	264	266
Prospect Park	68	69	70	71	72	73	73	74	74	74
Total Load	416	431	445	454	461	466	470	335	338	340
Electrification Adjustment	3	9	11	15	21	27	34	28	33	38
Other Adjustments	-6	-10	-12	-16	-16	-12	-14	-11	-11	-11
Net Load	413	430	444	453	466	481	490	352	360	367
Capability	497									
Feeder Capability @138 kV	532									
138 kV Feeder Loading	78%	81%	83%	85%	88%	90%	92%	66%	68%	69%
[S.E. 300-Hr Rating = 628 Amps]										
Farragut X-winding Load	293	310	324	333	346	361	370	232	240	247
Capability	373									
Farragut X-winding Loading	79%	83%	87%	89%	93%	97%	99%	62%	64%	66%
[TR5 S.E. 300-Hr Rating = 552 Amps]										

Relationship to Broader Company Plans, Initiatives and the NYS Climate Leadership and Community Protection Act
This project will not directly impact greenhouse gas emissions.

More than 50% of the geographical area of this network is classified as DAC. This project addresses potential future reliability issues in the Williamsburg network, reducing the potential for customer outages to the disadvantaged communities that it serves.

The Company expects general increases in load, as well as electrification of vehicles and heating. The Water Street area substation will encounter increasing overloads in the future when load increases to the point where it will match capacity. To address reliability design criteria and build in resiliency for various contingency events, the new Nevins substation will be placed into service by 2032. This project will improve the reliability of the Williamsburg Networks by allowing the Company to reduce network sizes and will establish feasible resiliency options for various contingency events, which are not available with the existing distribution system design.

The system improvements implemented with this project would be sufficient to address load growth across the networks supplied by the Water Street Area station: Williamsburg and Prospect Park.

This project is a core investment that enables the Company to continue to provide safe and reliable service, even as the nature of the grid changes. This aligns with Con Edison's strategic objective of providing world-class safety, reliability, and security, while managing the equity challenges of the energy transition.

This project supports the State's achievement of CLCPA and clean energy goals. This aligns with Con Edison's strategic objective to meet economy-wide net-zero GHG emissions in our service territories by 2050.

This project is a climate resilience investment that strengthens utility infrastructure to withstand extreme weather conditions and the physical impacts of climate change. This aligns with Con Edison's strategic objective to increase resilience of our energy infrastructure to adapt to climate change and address other threats and hazards.

By enabling load splits and smaller networks this program will progressively increase the reliability of the associated networks in both the near and long term. It will help the company avoid public safety issues related to network failure, customer outages and significant damage to company equipment. Also, it will protect customers from any issues related to network shutdown.

Resiliency plans: this program will help during problems in the transmission and/or substation which limits the load capacity in the Brownsville, Glendale, and Plymouth Street substations. Once this project is complete, it will be more feasible to transfer out or partially restore the load coming out of the area stations.

The main challenges to the Williamsburg network are the consistently higher corporate lower NRI (reliability) rankings and the highly loaded feeders with an increasing load forecast. The most economical and feasible solution is to introduce new feeders which will solve all those concerns with the network. The plans proposed in this paper are synergistic and complementary to the Climate Change Implementation Plan.

An added benefit to the work proposed in this white paper is that, as New York State continues its efforts to reduce greenhouse gas emissions, further electrification of the economy will challenge the secondary distribution system. Introducing new feeders will allow better distribution of the load per feeder and transformers. New transformers will be introduced in the network which will help balance the load amongst multiple transformers.

Risk management at the distribution level. By virtue of ranking in the top three positions in the NRI for Company over the last few years and with no expectations of being able to reduce this number meaningfully, the Williamsburg network is more susceptible to network shutdown relative to most networks in the system. This is despite different projects that have been conducted to try to improve the reliability of this network. The consequences would be severe for the company and the public. Public safety, disruption of public transportation, sever damage to company equipment and customer outages would be the immediate consequences. PSC penalties, reputational damage, increased regulatory scrutiny and severe financial impact would be the consequences in the longer timeframe. The severity of the consequences makes it more imperative that we address all underlying issues with the establishment of new feeders and reducing the large number of expected overloaded sections due to the low margins between feeder ratings and feeder loads.

2. Supplemental Information

Alternatives
The alternative solution is to transfer load out of Greenwood to nearby networks not part of the Water Street Area Station load supply area. There is no additional capacity in the three nearby stations: Plymouth, Brownsville and Bensonhurst.

Risk of No Action

An overload in the Water Street Area Station is predicted to occur. Many of Con Edison's Brooklyn/Queens substations are near full capacity and do not offer the feasibility of load transfer. In the event of an area station overload, load shedding may be required during peak conditions which would cause thousands of customers to encounter service outages.

Without pursuing the project, the Company networks will encounter the potential inability of maintaining reliable system power flow controls, system reliability and resiliency concerns and/or possible customer outages for an extended period during peak load condition.

Additionally, should the construction of the Nevins Area station be deemed necessary, and no action has been pursued, there may not be sufficient time available to build Nevins on time.

Network shutdown due to feeder cascading. All standard ways to improve reliability like thermally sensitive component replacement, introduce new feeders (not available cubicles), de-load highly loaded feeders by load balancing are not feasible or will have no significant impact. Due to this NRI ranking, this network is susceptible to shut down by feeder cascading of nearby related feeders. The fact that there are multiple feeders within their 90% emergency rating increases the load shift and increases the chances of feeder cascading. Loss of feeders causes large load shifts to nearby feeders which can then start the feeder cascading effect and potential network shut down. This is compounded during contingencies beyond design where large amounts of load would be picked up by nearby feeders that are already close to the emergency rating on second contingency. The waterfront around Kent Ave, which has become a popular place for developers to build skyscrapers is a very susceptible area because there is no support on the west side of the load pocket being a river. Only introducing new feeders that can reduce the average load per feeder will resolve future overloads and reliability issues.

Feeder overloads. There are 13 feeders within 90% of their normal rating and 11 feeders within their emergency rating. With time, as load grows, the need for load relief will increase year over year and remain high for the foreseeable future. This is an expensive process with no significant improvements in the NRI relative to the cost. The number of feeder overloads will keep increasing as load grows. There is an additional related risk caused by the low margins between the feeder loads and their rating. If there is unexpected load growth or load shifting within the network, it can cause feeder overloads that may require de-loading or load shedding plans if there is no time to solve the de-load before the summer peak. These overloads will also increase the NRI going into the summer if they are not resolved. Also, because of the low margin between the emergency rating and emergency load, there is a high risk that feeders will exceed emergency ratings during contingencies beyond design during peak heat in the summer. This will increase the chances of feeder cascading and network shutdown. All these risks will be eliminated under the plan proposed in this white paper by introducing new feeders and greatly reducing the average feeder load.

Non-Financial Benefits

This project will provide the necessary reliability and resiliency in an area of New York City that serves many critical loads and hospitals in a densely populated area where many buildings have elevators and various equipment loads. Relief of the Water Street Area station will ensure continued reliable service to the Williamsburg and Prospect Park networks and will allow the station to maintain the area substation N-1 reliability design criteria for long term projected load growth in this area of Brooklyn. This Project will also provide future relief to the Farragut Transmission switching station which provides service Water Street and the Prospect Park and Williamsburg Networks.

The increased capacity brought on by Nevins offers the potential to minimize impact on customers during an area station event that limits station capacity. Resiliency options are not feasible in this load pocket without the use of rolling blackouts and the use of mobile stations which require time-intensive set-up. By introducing new area station capacity and splitting current networks into smaller load areas, the Company will be able to handle loss of station capacity during emergencies and its impact on customers. If capacity at Water Street, Bensonhurst or Plymouth stations are compromised, load can be swapped between stations, minimizing, or eliminating the need for load shedding during an event.

Meeting New York's CLCPA goals will ultimately require the Company to build system capacity for an anticipated increase in load growth. With electrification of the City, as we move away from a carbon economy, we will require capacity in the affected networks to accommodate unprecedented load growth. Rapid load growth has the potential to leave the Company in a difficult position to address all the relief and reliability challenges soon.
Customers will be satisfied with much less construction in the long term because the large number of overloads expected in the current design will be resolved with this project. Otherwise, hundreds of sections will require load relief and excavation over the next few decades in different areas of this part of Brooklyn.

By decreasing the probability of a network shutdown, this program will increase the reliability and resiliency of the network in the long term. It will help the Company avoid public safety issues related to network failure, customer outages and significant damage to company equipment. Also, it will shield the company from any reputational issues related to network shutdown.

There will be fewer customer disruptions. This project will also help reduce outages because less stress on the feeders and eliminate all major load relief projects.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis (if required)
N/A

2. Major financial benefits
A financial benefit of this work is also cost avoidance at the feeder distribution level. Williamsburg has low margins between the feeder ratings and feeder loads. The network will require an increasingly growing budget over the next decades to address feeder overloads with little benefit to the reliability of the network. As the load increases, feeders will reach and go beyond their rating. The standard way available to resolve the overload is to install new duct and replace the overloaded section. This is an expensive proposition. An uptick in the load forecast, for example caused by the electrification of cars and heating, can increase the number of feeders that need expensive load relief. The work proposed in this paper will resolve all the overloaded sections by transferring loads out of existing feeders to new ones supplied by Nevins.

Another cost savings is that the much lower load per feeder gained by introducing new ones will reduce the stress on the feeders during summer contingencies. Avoidance of penalties related to potential network shutdown implied in the high NRI number is another benefit of this program.

3. Basis for estimate
The funding request is based on an initial order of magnitude estimate based on the scope of work and major equipment described above. The unit costing method was used to estimate the cost for the distribution system establishment of the Springfield network. The number of required units of equipment and material are multiplied by a loaded unit cost that contains material, labor and overheads. The initial scope of work was studied, and specific units of work needed were obtained at a high level.

Name	Unit Cost	Units	Total Cost
120/208V Transformer	$15,157	20	$470,000
Secondary Mains	$15,424	300	$7,172,000
Street Ties (4 sets of 4-500)	$5,581	44	$381,000
3-2/0 EPR (splicing included)	$30,297	25	$1,174,000
3-500 EPR (splicing included)	$39,280	0	$0
3-750 EPR (splicing included)	$51,504	0	$0
3-1000 EPR (splicing included)	$116,014	630	$113,287,000
M14	$70,439	315	$34,392,000
M11-6	$34,455	19	$1,015,000
MH Enlargement	$232,957	0	$0
Service Box	$10,740	9	$150,000
V13-6	$71,551	18	$1,996,000
Roadway Conduit 6"	$798	77,000	$95,241,000
Roadway Conduit 4" & 5"	$558	12,000	$10,379,000
Vacuum Switches	$106,364	14	$2,308,000
Cam-ops	$41,394	14	$898,000
		Sum =	$268,863,000

Project Risks and Mitigation Plan

Risk 1:
Permitting by the city, Park departments, MTA and LIRR Interference, find lanes for ducts to be installed.

Mitigation Plan 1:
Identify issues early via surveys and engage stakeholders to get permits and find clear lanes.

Risk 2:
Interference with city contractors/paving coordination

Mitigation Plan 2:
Coordinate with city and DOT to get access and schedule work to avoid conflicts.

Risk 3:
Crossing major roadways and parks.

Mitigation Plan 3:
Avoid crossings by rerouting. If not possible engage early to find different construction techniques like boring to cross major roadways, train lanes and park if possible. Place Area Station closer to the load to be transferred to avoid difficult crossings.

Risk 4:
Delays due resource/support coordination. There are a large number of projects to expand the electric distribution system that may strain existing resources.

Mitigation plan 4:
Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts. Expand hiring and increase the number of employees over the next few years to be able to handle the increased flow of work.

Risk 5:
Material Availability Issues

Mitigation plan 5:
Engineering will work with Supply Chain to establish a cohesive plan that aligns with vendor lead times. Stay engaged with vendors to ensure lead times are maintained, and adjust the plan as needed if shortages are encountered.

Risk 6:
One major risk is for load to increase faster than forecasted which will cause load to exceed equipment ratings before completion of projects to de-load such equipment.

Mitigation Plan 6:
Start projects early and on a longer cycle to allow for acceleration if the need arises.

Technical Evaluation / Analysis
N/A

Project Relationships (if applicable)
This project requires the completion of the new Nevins St. Area Substation.

3. Funding Detail ($000)

Historic Spend

	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Test Year* (O&M Only)	Forecast 2024
O&M	$0	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	N/A	$0
Capital	$0	$0	$0	$0	N/A	$0

2025-2029 Request:
Total Request by Year:

	2025	2026 (RY1)	2027 (RY2)	2028 (RY3)	2029
O&M	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	$0
Capital (Total)	$0	$5,000	$10,000	$52,700	$61,900
Labor	$0	$648	$1,296	$6,831	$8,024
M&S	$0	$1,327	$2,655	$13,991	$16,433
Contract Svcs.	$0	$1,799	$3,598	$18,964	$22,274
Other	$0	$278	$556	$2,932	$3,444
Overheads	$0	$947	$1,894	$9,982	$11,724

*The test year runs from 10/1/2023 to 9/30/2024

Electric Operations / Distribution Engineering
2025-2029

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: White Plains and Elmsford No. 2 to Grasslands – White Plains (8W) and Elmsford No. 2 (12W) to Grasslands (19W) Transfers	
Project/Program Manager: Kevin Oehlmann	**Project/Program Number (Level 1):** 28018336
Status: ☒ **Initiation/Planning** ☐ **In-Progress (Projects Only)** ☐ **On-going (Programs Only)**	
Estimated Start Date: 2026	**Estimated Date In Service:** 2033
2025-2029 Funding Request ($000) **Capital:** $14,000 **O&M:** $0	

Work Description:
The preliminary "2025-2034 Area Substations and Sub-transmission Feeders Ten-Year Relief program" based on the latest load forecast (November 2024), concludes that the Elmsford load pocket requires a load transfer in 2033 to relieve constraints on sub transmission feeders that support the load area. As a result, approximately 32 MW of load will be transferred from the Elmsford to the Grasslands area substations in 2033 and approximately 52MW will be transferred from the White Plains to the Grasslands area substations in 2033.

Major Scopes of Work:
- Installation of new conduit systems, including civil works to cross multiple highways and overpasses within the network footprint.
- Installation of new underground (UG) and overhead (OH) aerial cables to connect the newly established feeders.
- Installation of new underground and overhead structures to support the additional feeder infrastructure.
- Coordination with external engineering consultants for the design and permitting of conduit systems, particularly for complex crossings.

Major or Long Lead Equipment Requirements:
- **Conduit Systems:** Procuring non-class and stock material to construct the necessary infrastructure that will house cables to transverse barriers such as highways and overpasses.
- **Underground Structures:** Procuring standard structural housing where underground feeder cables will be spliced to support the feeder network expansion.
- **Overhead Structures:** Procuring overhead fixtures which are storm hardened for northeast environmental conditions that will facilitate the installation of aerial feeder cables to support the feeder network expansion.
- **Underground and Aerial Cables:** Installation in multiple sections.

To accomplish the transfer of load in a timely manner, all engineering designs and planning are to be completed in advance. The planning and designing for cables installations across multiple highways in Westchester County is crucial. These crossings are the only routes to bring new feeders from

Grasslands area substation to the Elmsford and White Plains load areas. Con Edison will have to retain engineering consulting services to complete initial and detailed designs for civil construction on the overpasses. Prior to performing civil construction on the overpasses, DOT coordination and approval are required, taking an average of approximately two years.

Justification Summary:

Based on forecasted load growth for the Eastview- Elmsford load pocket which is comprised of three Area Substations – Elmsford No.2, White Plains and Harrison, the sub-transmission feeders will surpass their capability by 2033. Additionally, White Plains Area Substation will be projected to utilize its 1-hour capability in 2033 and exceed it in 2036.

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Elmsford No. 2	160	165	169	172	174	175	176	177	178	179	180	181	182	183	183	184	185	185	186	187
Electrification Adjustment	1	3	5	8	10	13	16	19	22	25	27	29	32	34	36	38	40	42	43	44
Other Adjustments	-6	-8	-10	-13	-13	-12	-13	-14	-14	-15	-16	-16	-17	-17	-18	-18	-19	-20	-20	-21
Net Load	155	160	164	167	171	176	179	182	186	189	191	194	197	200	201	204	206	207	209	210
Capability	239																			
White Plains	210	220	229	236	242	244	247	249	251	253	255	257	259	261	263	264	266	267	269	270
Electrification Adjustment	3	5	8	12	18	24	30	36	42	47	52	56	60	64	67	70	72	73	74	74
Other Adjustments	-9	-15	-19	-21	-23	-22	-23	-24	-25	-26	-27	-28	-29	-30	-31	-32	-34	-35	-36	-37
Net Load	204	210	218	227	237	246	254	261	268	274	280	285	290	295	299	302	304	305	307	307
Capability	265																			
1-Hour Capability	281																			
Harrison	199	205	211	215	218	219	220	222	223	224	225	226	227	228	229	230	231	232	233	234
Electrification Adjustment	1	5	5	8	10	13	16	19	21	24	26	28	30	32	33	34	35	36	37	38
Other Adjustments	-5	-7	-10	-13	-14	-14	-15	-16	-16	-18	-18	-19	-20	-21	-21	-21	-22	-23	-24	-25
Net Load	195	203	206	210	214	218	221	225	228	230	233	235	237	239	241	243	244	245	246	247
Capability	243																			
1-Hour Capability	258																			
Eastview-Elmsford Load	554	573	588	604	622	640	654	668	682	693	704	714	724	734	741	749	754	757	762	764
Feeder Peak Diversity	1	0	2	4	6	10	10	11	11	14	15	16	16	16	18	17	19	21	19	20
Net Load	555	573	590	608	628	650	664	679	693	707	719	730	740	750	759	766	773	778	781	784
Post-Contingency Capability	685																			
Deficit									8	22	34	45	55	65	74	81	88	93	96	99
138 kV Feeder Loading	81%	84%	86%	89%	92%	95%	97%	99%	101%	103%	105%	107%	108%	109%	111%	112%	113%	114%	114%	114%

Transferring 32 MW from the Elmsford Area Substation to the Grasslands Area Substation in 2033 and 52MW from the White Plains Area Substation to the Grasslands Area Substation in 2033 will bring the sub-transmission feeder loading back to within their nominal limits. This load transfer addresses not only addresses the sub-transmission feeder loading but also the White Plains Area Substation overloads that is projected for 2036.

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Elmsford No. 2	160	165	169	172	174	175	176	177	146	147	148	148	149	150	150	151	152	152	153	153
Electrification Adjustment	1	3	5	8	10	13	16	19	18	21	22	24	26	28	30	31	33	34	35	36
Other Adjustments	-6	-8	-10	-13	-13	-12	-13	-14	-11	-13	-13	-13	-14	-14	-15	-15	-16	-16	-16	-17
Net Load	155	160	164	167	171	176	179	182	153	155	157	159	161	164	171	167	169	170	172	172
Capability	239																			
White Plains	210	220	229	236	242	244	247	249	199	201	202	204	205	207	209	209	211	212	213	214
Electrification Adjustment	3	5	8	12	18	24	30	36	33	37	41	44	48	51	53	55	57	58	59	59
Other Adjustments	-9	-15	-19	-21	-23	-22	-23	-24	-20	-20	-21	-22	-23	-24	-24	-25	-27	-28	-29	-30
Net Load	204	210	218	227	237	246	254	261	212	218	222	226	230	234	238	239	241	242	243	243
Capability	265																			
1-Hour Capability	281																			
Harrison	199	205	211	215	218	219	220	222	223	224	225	226	227	228	229	230	231	232	233	234
Electrification Adjustment	1	5	5	8	10	13	16	19	21	24	26	28	30	32	33	34	35	36	37	38
Other Adjustments	-5	-7	-10	-13	-14	-14	-15	-16	-16	-18	-18	-19	-20	-21	-21	-21	-22	-23	-24	-25
	195	203	206	210	214	218	221	225	228	230	233	235	237	239	241	243	244	245	246	247
Capability	243																			
1-Hour Capability	258																			
Eastview-Elmsford Load	554	573	588	604	622	640	654	668	593	603	612	620	628	637	650	649	654	657	661	662
Feeder Peak Diversity	1	0	2	4	6	10	10	11	11	14	15	16	16	16	18	17	19	21	19	20
Net Load	555	573	590	608	628	650	664	679	604	617	627	636	644	653	668	666	673	678	680	682
Post-Contingency Capability	685																			
138 kV Feeder Loading	81%	84%	86%	88%	91%	93%	95%	98%	87%	88%	89%	91%	92%	93%	95%	95%	95%	96%	96%	97%

The load transfer is critical to the continuation of providing reliable electric service to our customers as the demand for electricity continues to grow through electrification and incremental load growth. This project will result in bringing the sub-transmission feeders that feed the White Plains and Elmsford load pockets operating within their capability limits and maintaining capacity for future load growth.

Relationship to Broader Company Plans, Initiatives and the NYS Climate Leadership and Community Protection Act

This project will not directly impact greenhouse gas emissions.

This project strengthens the Con Edison electric system in the areas served by these facilities, including service to disadvantaged communities.

This project is a core investment that enables the Company to continue to provide safe and reliable service, even as the nature of the grid changes. This aligns with Con Edison's strategic objective of providing world-class safety, reliability, and security, while managing the equity challenges of the energy transition.

This project supports the State's achievement of CLCPA and clean energy goals. This aligns with Con Edison's strategic objective to meet economy-wide net-zero GHG emissions in our service territories by 2050.

This project is a climate resilience investment that strengthens utility infrastructure to withstand extreme weather conditions and the physical impacts of climate change. This aligns with Con Edison's strategic objective to increase resilience of our energy infrastructure to adapt to climate change and address other threats and hazards.

2. Supplemental Information

Alternatives

Initial evaluation of 80 MW transfer from White Plains. The 80 MW load transfer was split into two transfers due to the physical location of each area station in relation to their load pockets. The White Plains area substation is located further away from the Grassland area substation in comparison to the Elmsford area substation. This presents a major challenge to transfer the 80 MW as the distribution feeders would have to traverse across multiple highways and longer feeders. The Elmsford area substation is closer in proximity to the Grassland area substation and requires less highway crossing; therefore, transferring 32 MW of load from Elmsford to Grassland provides financial and design benefits as opposed to transferring 80 MW from White Plains to Grassland.

Another alternative is to set up and run mobile generators in this area during peak load periods; however, diesel generators pose an environmental hazard and do not support the Company's goals of delivering clean reliable energy to its customers.

Risk of No Action

Without any action, the sub-transmission feeders that serve White Plains and Elmsford area substations are projected to exceed their load capability in 2033.

Non-Financial Benefits

Pursing the Elmsford to Grasslands and White Plains to Grasslands Load Transfer project will allow the state of New York to stay on track on satisfying its environmental commitment (CLCPA) which ultimately benefits the ratepayers of Westchester with access to reliable energy for electrification of heat and vehicles. Additionally, the project will support future economic growth in the area by ensuring that the electrical infrastructure can accommodate increased demand without compromising reliability.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)
N/A

2. Major financial benefits
N/A

3. Basis for estimate
The estimated costs are based on the cost for similar types of work accomplished as part of previous projects. The initial estimate for the work is outlined below.

		2026	2027	2028	2029	2030	2031	2032	2033			
Project	**Activities**	**Units**	**Units**	**Units**	**Units**	**Units**	**Units**	**Units**	**Units**	**Total**	**Unit Cost**	**Total Cost**
Elmsford-White Plains-Grasslands 80 MW transfer	Engineering Consultant	*	*	*	*							$ 12,000,000
	Install Conduit				1,180	31,348	31,348	31,347		95,223	$ 847	$ 80,653,881
	Install UG Structures				14	69	69	68		220	$ 68,932	$ 15,165,040
	Install UG Cable					168	168	167		503	$ 52,455	$ 26,384,865
	Install Aerial Cable							350	349	699	$ 18,273	$ 12,772,827
	Install Poles							230	229	459	$ 17,071	$ 7,835,589
												$ 154,812,202

*The company estimates that $12M in funding in 2026 – 2029 will be used to complete the designs needed for highway, railroad and waterway crossings.

Project Risks and Mitigation Plan

Risk 1: The potential risks that exist for the project are insufficient resources regarding labor, delays with material due to supply chain issues, and escalating cost.

Mitigation Plan 1: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts. In addition, to explore an alternative mutually beneficial contract structure for the anticipated civil work and ordering equipment in advance of lead time to hedge against rising commodity cost.

Technical Evaluation / Analysis

N/A

Project Relationships (if applicable)

This project is facilitated by the Grasslands Install Fourth Transformer with its 138 kV Supply Feeder project to be executed by SSO.

3. Funding Detail ($000)

Historic Spend

	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Test Year* (O&M Only)	Forecast 2024
O&M	$0	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	N/A	$0
Capital	$0	$0	$0	$0	N/A	$0

2025-2029 Request:

Total Request by Year:

	2025	2026 (RY1)	2027 (RY2)	2028 (RY3)	2029
O&M	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	$0
Capital (Total)	$0	$3,000	$3,000	$3,000	$5,000
Labor	$0	$389	$389	$389	$648
M&S	$0	$796	$796	$796	$1,327
Contract Svcs.	$0	$1,080	$1,080	$1,080	$1,799
Other	$0	$167	$167	$167	$278
Overheads	$0	$568	$568	$568	$947

*The test year runs from 10/1/2023 to 9/30/2024

Electric Operations / Distribution Engineering

2025-2029

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Corona No. 1 to Hillside No. 1 Transfer	
Project/Program Manager: Frantz St. Phar	**Project/Program Number (Level 1):** 27719605
Status: ☒ **Initiation/Planning** ☐ **In-Progress (Projects Only)** ☐ **On-going (Programs Only)**	
Estimated Start Date: 2027	**Estimated Date In Service:** 2033
2025-2029 Funding Request ($000) **Capital:** $219,759 **O&M:** $0	

Work Description:

The Company's 2024 Forecast projects Corona No.1 Area Substation to be overloaded beginning in 2032. To relieve this forecast load constraint, Con Edison is planning to split the Flushing (7Q) network and non-network(radial load) currently served by the Corona No. 1 Area Substation into two separate load areas, a smaller Flushing network that continues to be served by Corona No. 1 and a new network (Bayside) to be served by a new Hillside Area Substation (Con Edison is still finalizing the exact location where the Hillside Area Substation will be located, so in order to develop design this project Con Edison assumed this substation will be located at 42nd Avenue and 172nd Street). Under this project Con Edison plans to split the current Flushing network while a separate project establishes the new Hillside Area Substation (See the Establish Hillside Area Substation white paper).
Corona No.1 Area Substation has a net load of 398 MW, with the Flushing (7Q) network having 28 network feeders and 2 non-network feeders with approximately 130,000 electric customers. Once Con Edison splits the network, the northern portion of the current 7Q network will be served by the new Hillside Area Station while the southern portion remains in the Flushing network supplied by Corona No. 1.

Con Edison's Flushing network consists of four clearly segregable load areas. The southern and western portions of the network are comprised of secondary distribution networks. The center east and northern portions have non-network distribution systems with some small pockets of embedded secondary network. The load areas Con Edison is targeting to create the new network to take advantage of the natural separations that currently exist and include the Flushing 4KV grid, the Flushing multibank, four autoloops, and some small pockets of embedded secondary network inside the larger non-network load areas. The four main systems comprising the current 7Q network are independent (i.e., not connected at the distribution level) but share primary feeders supplying them from Corona No. 1.

New feeders from the new Hillside Area Station will be extended to strategic points to pick up the feeders supplying the three non-network radial systems which are located mostly in the central, north, and east side of the network east of Bell Blvd & North of 33 Ave. Any primary feeder connections from Corona will then be severed and this load will then be fed from the new Hillside substation and will be referred to as the Bayside network. The Hillside Area Substation will supply the new Bayside network

that will be established from the approximately 150 MW load split from Flushing network load and 28 MW Radial load in 2033. Due to the feasibility of constructing Hillside and executing load transfers, the earliest date is 2033, although the need date is 2032. Load relief solutions to address the 2032 deficit are being evaluated.[=

The now much smaller, more reliable Flushing network will continue to be supplied by the Corona No. 1 Area Substation through the existing 28 network feeders.

To supply the new Bayside network, Con Edison will extend 24 feeders from the newly established Hillside station to the load area being segregated. The project will maximize the use of the new feeders to increase reliability and allow for load growth. Sixteen (16) feeders will be used to supply the 4 KV grid and small embedded network load, four (4) feeders will supply the Flushing multibank, and four (4) feeders will supply the four (4) autoloops.

Con Edison will install 1000 mcm cable from Hillside to the pick-up points just south and west of the future boundaries of the two networks. Figure 1, below, shows the way the new feeders will run to pick up the load being dropped from the Flushing Network.

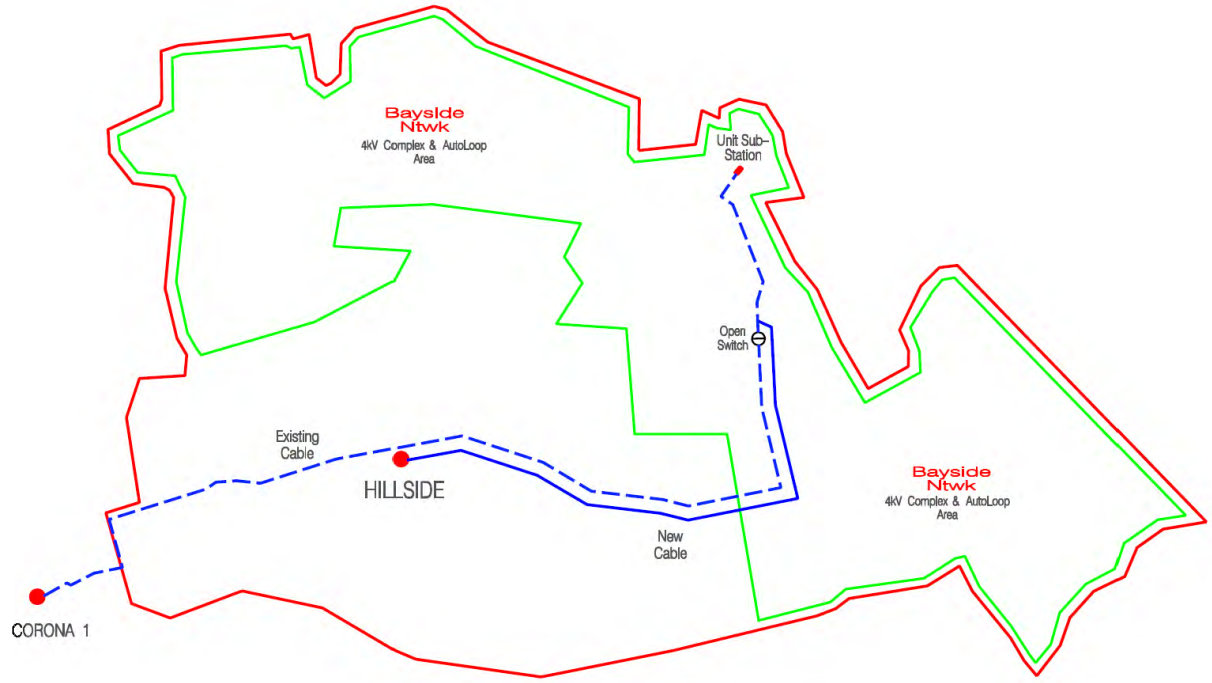


Figure 1. Overall feeder run from Hillside and Corona 1 stations showing how the new Hillside feeders will pick up the load to create the new Bayside Network.

A prerequisite to this work is the establishment of the new Hillside Area station which is a separate project. This station is a new indoor 27kV area substation that will be arranged in a double SYN bus configuration with four 93.3 MVA 138kV/27kV transformer banks and 30 MVAR capacitor. The station will be supplied from the new 345kV Eastern Queens switching station. This station will allow for added resiliency to the network and additional transmission capacity to mitigate deficiencies in the Jamaica load pocket as well.

The primary scopes of work involved in the establishment of the new Bayside Network are shown below:

- Install or replace 316,468 trench feet of conduit.
- Install or replace 1,436 sections of primary cable.

- Install or replace 300 sections of secondary cable.
- Install or replace 30 120/208V transformers.
- Install or replace 1,043 underground manholes/vaults.
- Install or replace 9 service structures.

Major or long-lead equipment requirements for the project include, but are not limited to:

Major Equipment Type	Number to be Purchased
120/208V Transformers	30
Roadway Conduit 6" (1 Unit = 100 LF)	3,045
Roadway Conduit 4" & 5" (1 Unit = 100 LF)	120
Secondary Mains (sections, 250-ft each)	300
3-2/0 EPR (splicing included) (sections, 250-ft each)	35
3-500 EPR (splicing included) (sections, 250-ft each)	48
3-1000 EPR (splicing included) (sections, 250-ft each)	1,353
Manholes	1,015
Vaults	28
Service Boxes	9
Vacuum Switches w/SCADA	24
Cam-Op Disconnect Switches	24

Engineering and long lead equipment procurement will begin in 2027 for this project and construction is expected to begin in 2029 and to be completed in 2033. The estimated, high-level timeline is below. This timeline is subject to change at any time, as the Company optimizes the project schedule and incorporates impacts of other projects and system performance.

Justification Summary:

Con Edison forecasts the Corona No.1 Area Substation will meet and exceed its capacity based on The Company's 2024 Load Forecast in 2032. Due to timeline constraints, the earliest the Company can get Hillside Area Substation in-service is 2033, therefore the company will execute the load transfer from Corona No.1 to Hillside in 2033, and a load relief solution to address the 2032 overload is being evaluated. Con Edison plans to split the Flushing network into two smaller networks in order to de-load Corona No.1 under this project.

Con Edison's current 20-Year Load Forecast shows an enduring upward trend of peak demand growth at the network level driven by increased building and transportation electrification that continues to drive the need for load relief at the area station and transmission supply feeder level to maintain reliability design criteria and to meet climate resiliency objectives. The main drivers to load growth in the long-term forecast are climate change adjustments that we use in our design model, new business increase, electric vehicles deployment, buildings moving to full electric heating and organic load growth. The split of the Flushing network will improve the reliability of all networks by reducing the network sizes and de-load the overloaded substation equipment. See below load forecast for Corona No. 1.

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Corona No. 1																				
Flushing	376	389	408	430	434	437	439	441	443	445	447	449	451	453	454	456	458	459	460	462
Radial	25	25	25	26	26	27	27	27	28	28	28	29	29	29	29	30	30	30	31	31
Total Load	401	414	433	456	460	464	466	468	471	473	475	478	480	482	483	486	488	489	491	493
Electrification Adjustment	5	9	16	21	29	38	47	57	68	80	93	105	118	131	144	158	171	185	198	212
Other Adjustments	-8	-10	-13	-15	-15	-11	-11	-11	-12	-13	-13	-13	-14	-15	-15	-16	-17	-18	-18	-20
Net Load	398	413	436	462	474	491	502	514	527	540	555	570	584	598	612	628	642	656	671	685
Capability	511																			
deficits								3	16	29	44	59	73	87	101	117	131	145	160	174

The plan is to de-load the Corona No. 1 by splitting the Flushing(7Q) network into two separate networks: The new Bayside network encompassing all the non-network load north and east of the current Flushing network will be transferred to the newly established Hillside Area Station.

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Corona No. 1																				
Flushing	376	389	408	430	434	437	439	441	293	294	296	297	298	300	300	302	303	304	304	306
Radial	25	25	25	26	26	27	27	27	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	401	414	433	456	460	464	466	468	293	294	296	297	298	300	300	302	303	304	304	306
Electrification Adjustment	5	9	16	21	29	38	47	57	45	53	62	69	78	87	95	105	113	122	131	140
Other Adjustments	-8	-10	-13	-15	-15	-11	-11	-11	-8	-9	-9	-8	-9	-10	-10	-11	-11	-12	-12	-13
Net Load	398	413	436	462	474	491	502	514	330	338	349	358	367	377	385	396	405	414	423	433
Capability	511							TBD												

Relationship to Broader Company Plans, Initiatives and the NYS Climate Leadership and Community Protection Act

This project will not directly impact greenhouse gas emissions.

This project strengthens the Con Edison electric system in the areas served by these facilities, including service to disadvantaged communities.

This project is a core investment that enables the Company to continue to provide safe and reliable service, even as the nature of the grid changes. This aligns with Con Edison's strategic objective of providing world-class safety, reliability, and security, while managing the equity challenges of the energy transition.

This project supports the State's achievement of CLCPA and clean energy goals. This aligns with Con Edison's strategic objective to meet economy-wide net-zero GHG emissions in our service territories by 2050.

2. Supplemental Information

Alternatives

The alternative solution is to transfer the load out of Corona No. 1 area station to nearby networks. There is no additional capacity in the nearby area substations, including Corona No. 2 and Glendale to support load transfer from Corona No. 1. In any case, the amount that could be transferred out is limited by natural and manmade barriers.

Risk of No Action

An overload in Corona 1 is predicted to occur. Many of Con Edison's Brooklyn/Queens substations are near full capacity and do not offer the feasibility of load transfer. In the event the area station overloads, load shedding may be required during peak conditions which would cause thousands of customers to encounter service outages.

Without pursuing the project, the Company networks will encounter the potential inability of maintaining reliable system power flow controls, system reliability and resiliency concerns and/or possible customer outages for an extended period during peak load condition.

Additionally, should the de-load of Corona No.1 be deemed necessary, and no action has been pursued, there may not be sufficient time available to de-load the Corona No.1 station via the split of the Flushing Network.

Non-Financial Benefits

The Company expects general increases in load, as well as electrification of vehicles and heating. The Flushing network and its supply area station Corona No.1 will encounter increasing loads in the future to the point where it will match and then exceed its capacity. To address reliability design criteria and build in resiliency for various contingency events, the new Hillside substation will be placed into service by 2033 to de-load Corona No. 1. This project will improve the reliability of the Corona No. 1 network by allowing the Company to reduce network sizes and will establish feasible resiliency options for various contingency events, which are not available with the existing distribution system design. Disadvantaged communities and underserved communities will benefit from this project by allowing electrification and EV deployment due to the increased station capacity. It will allow cleaner, greener sources of energy with reduced pollution and cleaner air in the DAC areas. The Project will facilitate achievement of State and City emissions goals by facilitating electrification. The Project will create headroom for future customer growth in the network fed by Corona No. 1. Hillside will be established with 358 MWs of capacity, much less than the load transferred from Corona No.1 to create the Bayside network. Therefore, creating ample capacity for load growth in the Bayside Network and by allowing future load transfers from Corona No.2 and thereby creating capacity in the networks fed by Corona No. 2. This will support the effort for electric vehicle adaptation, electrification of hot water heaters, stovetops, ovens, and clothes dryers, and new business. Over the long run, as electrification of heating becomes more mainstream, the project will also enable the additional margin to support progress towards New York State's clean energy future goals. Accordingly, this Project will enable achievement of CLCPA goals, not just by enabling electrification, but because it will benefit disadvantaged communities through improved reliability.

The system improvements implemented with this project would be sufficient to address load growth across the networks supplied by the Corona No.1 and Corona No.2 Area stations: Flushing, Jackson Heights and Rego Park. Corona No. 2 networks will benefit because a load transfer to Hillside is planned in the future in order to de-load Corona No.2. This will satisfy reliability, resiliency, safety, and compliance regulations.

By enabling load splits and smaller networks this program will progressively increase the reliability of the associated networks in both the near and long term. It will help the Company avoid public safety issues related to network failure, customer outages and significant damage to company equipment. Also, it will protect customers from any issues related to network shutdown.

Resiliency plans: this program will help during problems in the transmission and/or substation that limits the load capacity in the Corona No. 1 and Glendale substations. Once this project is complete, it will be more feasible to transfer out or partially restore the load coming out of the area stations.

Flushing is ranked as the number 5 worst network out of 64 in the network reliability rankings. This network ranking is expected to get worse with time. The increasing load forecast, accompanying increase in load per feeder, reduction in the margins between the load and the feeder capacity and aging of equipment will worsen the reliability of the network. Reducing load per feeder, creating new feeders, and reducing the length of feeders are known ways to improve the reliability of the network and improve the NRI. The most economical and feasible solution is to reduce the load per feeder which will occur when we split the network load. The plan proposed in this paper are synergistic and complementary to the Climate Change Implementation Plan. The reliability, resiliency and load relief

improvements in this network are complementary and a necessary step to manage the climate risk imposed by global warming and electrification.

An added benefit to the work proposed in this white paper is that, as New York State continues its efforts to reduce greenhouse gas emissions, further electrification of the economy will challenge the secondary distribution system. Reducing the load will decrease the load per feeder and transformers.

Risk management at the distribution level. By virtue of ranking in the top 5 worst in the network reliability Index (NRI), with no expectations of being able to reduce this number meaningfully, the Flushing network will be susceptible to network shutdown relative to most networks in the system. The consequences would be severe for the Company and the public. Public safety, disruption of public transportation, severe damage to Company equipment and customer outages would be the immediate consequences. PSC penalties, reputational damage, increased regulatory scrutiny and severe financial impact would be the consequences in the longer timeframe.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)
N/A

2. Major financial benefits
N/A

3. Basis for estimate
The funding request is based on an initial order of magnitude estimate based on the scope of work and major equipment described above. The unit costing method was used to estimate the cost for the distribution system establishment of the Bayside network. The number of required units of equipment and material were identified and multiplied by a loaded unit cost that contains material, labor, escalation, overheads, and contingency. The initial scope of work was studied and specific units of work needed were obtained at a high level.

Name	Units	Total Unit Cost	Total Cost
120/208V Transformer	30	$33,333	$1,000,000
Secondary Mains	300	$26,667	$8,000,000
Street Ties (4 sets of 4-500)	44	$9,773	$430,000
3-2/0 EPR (splicing included)	35	$57,143	$2,000,000
3-500 EPR (splicing included)	48	$62,500	$3,000,000
3-1000 EPR (splicing included)	1353	$203,252	$275,000,000
M14	991	$123,108	$122,000,000
M11-6	24	$41,667	$1,000,000
Service Box	9	$18,778	$169,000
V13-6	28	$142,857	$4,000,000
Roadway Conduit 6"	304,468	$1,396	$425,000,000
Roadway Conduit 4" & 5"	12,000	$1,000	$12,000,000
Vacuum Switches	24	$166,667	$4,000,000
Cam-ops	24	$83,333	$2,000,000
	Sum =		**$860,000,000**

Project Risks and Mitigation Plan

Risk 1:

The project is likely to require multiple permits from various New York City agencies, permit processes could lead to delays. In addition existing New York City, MTA, and LIRR infrastructure along planned routes needs to be identified and could lead to design changes or modifications, which could also result in project delays.

Mitigation Plan 1: Identify issues early via surveys and engage stakeholders to get permits and find clear lanes.

Risk 2:

Interference with city contractors/paving coordination

Mitigation Plan 2:

Coordinate with New York City agencies including NYCDOT to get access and schedule work to avoid conflicts.

Risk 3:

Crossing major roadways and parks will require coordination and special design consideration with responsible government agencies.

Mitigation Plan 3:

Avoid crossings by rerouting. If not possible engage stakeholders early to plan alternative construction techniques, such as boring to cross major roadways, train lanes and park if possible. Evaluate Area Station siting and feeder routing considerations to avoid difficult crossings.

Risk 4:

Delays due resource/support coordination. There are a large number of projects to expand the electric distribution system that may strain existing resources.

Mitigation plan 4:

Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts. Expand hiring and increase the staffing to appropriate levels to support the increased work scale.

Risk 5:

Material Availability Issues

Mitigation plan 5:

Engineering will work with Supply Chain to establish a cohesive plan that aligns with vendor lead times. Stay engaged with vendors to ensure lead times are maintained, and adjust the plan as needed if shortages are encountered.

Risk 6:

One major risk is for load to increase faster than forecasted which will cause load to exceed equipment ratings before completion of projects to de-load such equipment.

Mitigation Plan 6:

Start projects early and on a longer cycle to allow for acceleration if the need arises.

Central Operations / Substation Operations

2025-2029

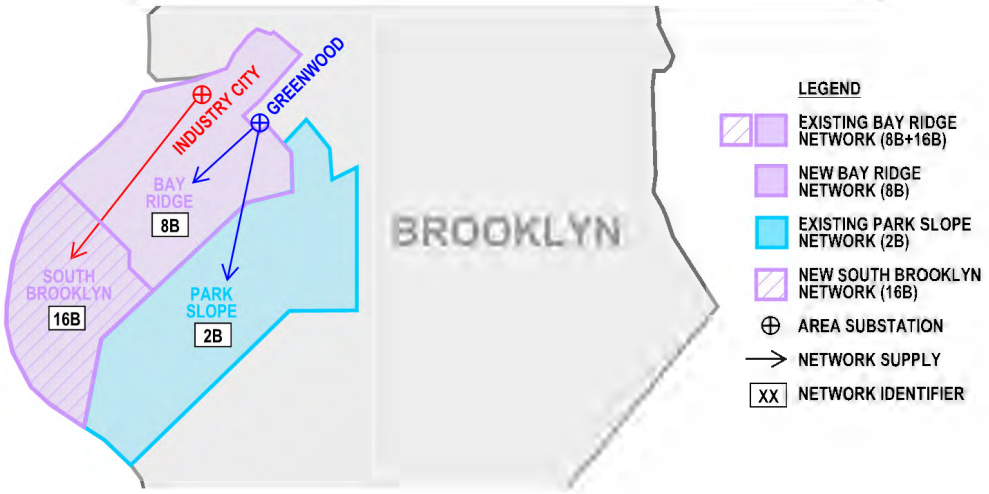
1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Brooklyn Expansion: Sunset Park 345 kV S/S and Industry City 27kV Area Substation	
Project/Program Manager:	**Project/Program Number (Level 1):** 27809975
Status: ☒ **Initiation/Planning** ☐ **In-Progress (Projects Only)** ☐ **On-going (Programs Only)**	
Estimated Start Date: 2026	**Estimated Date In Service:** 2034
2025-2029 Funding Request ($000) **Capital: $ 560,000** **O&M:** $0	

Work Description:

The Brooklyn Expansion project is a three-part project that will address a reliability need in the Greenwood 138kV Transmission Load Area (TLA) and provide load relief to the Greenwood 27kV Distribution Area Substation. The overall project will consist of three parts: 1. Building a new 345kV transmission substation, the Sunset Park 345kV Transmission Substation ("Sunset Park"), which will supply the new Industry City 27kV Distribution Area Substation; 2. Building the new Industry City 27kV Distribution Area Substation ("Industry City"); and 3. Transferring approximately 80 MW from the Bay Ridge Network to the new Industry City 27kV Distribution Area Substation, thereby creating the new South Brooklyn Network ("South Brooklyn"). Both substations will be co-located on a vacant parcel of Company-owned land at 29th Street and 3rd Avenue in Brooklyn.

Greenwood Substation - Bay Ridge Network Cutover Concept



Sunset Park will be designed as an indoor 345kV Gas Insulated Switchgear Transmission Substation,

arranged in a double ring bus configuration with provisions for future points of interconnection. The initial construction will include four (4) 345kV connections (expandable to 5) to supply Industry City. To connect to the Con Edison Transmission System, the Company will bifurcate existing 345kV Feeders 25 and 26, between Goethals Substation and Gowanus Substation, creating four (4) new 345kV connections. In the future, with additional expansion, Sunset Park will be capable of supplying 345kV connections to expand the Eastern Queens Transmission Substation as well as offer Points of Interconnection (POI) for renewable resources such as Off-Shore Wind (OSW).

The Industry Park 27 kV Distribution Area Substation will be designed as an indoor substation with all switchgear sections, battery rooms, test equipment, control room in one control building with the latest substation reliability enhancements incorporated. The station bus arrangement will use two (2) separate, non-connected SYN buses to connect the transformers. The initial construction will include four (4) transformer banks (expandable to 5). Each transformer bank will feed two (2) switchgear sections with five (5) feeders each, for a total of forty (40).

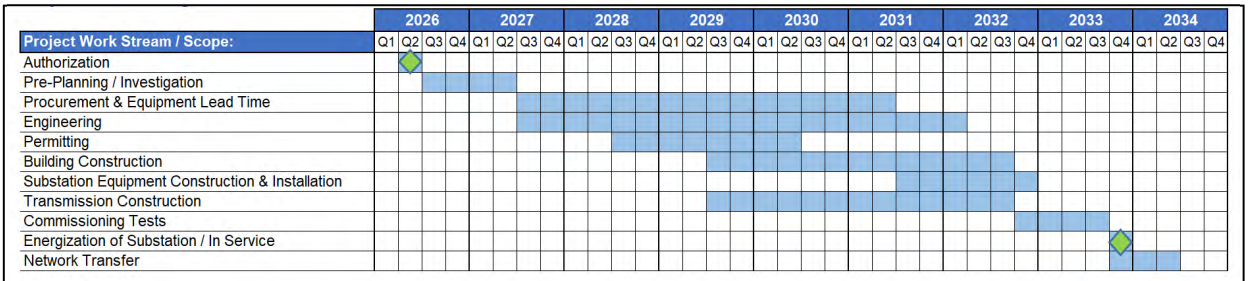
The major scopes of work to be completed to establish the Brooklyn Expansion project include:

- Property Acquisition (completed)
- Engineering Package Development
- Site Demolition & Remediation
- Pouring of Foundation
- Erection of Building Structure
- Completion of Building Interiors (Mechanical, Electrical & Plumbing)
- Procurement and Installation of Substation Equipment
- Completion of Sub-Transmission Feeder Installations
- Completion of Substation Terminations and Commissioning

Major equipment requirements for the project include, but are not limited to:

Major Equipment Type	Number to be Purchased
345kV Gas-Insulated Switchgear Breaker Sections	14
345kV Gas-Insulated switchgear	1
345/138/13kV 300MVA Auto-Transformer	4
345kV Circuit Switcher & Interrupter	4
138/27kV 93MVA Transformer	4
138kV Circuit Switcher & Interrupter	4
27kV Switchgear Sections	4
L&P Transformer	2

Engineering and long lead equipment procurement are expected to begin in 2026 for this project and station construction is expected to begin in early 2029. The estimated timeline to complete construction of the Sunset Park & Industry City Substations is below. This timeline is subject to change at any time, as the Company optimizes the project schedule and incorporates impacts of other projects and system performance. The in-service date for the Sunset Park substation is April 2034, the in-service dates for the Industry City and the South Brooklyn Networks are May 2034.



Justification Summary:

The Greenwood 27 kV Distribution Area Substation along with Bensonhurst No. 1 & No. 2 27 kV Distribution Area Substations are located within the Greenwood 138 kV TLA. Based on the latest load forecast numbers, additional deficits of 40MW in 2030 and 80MW in 2031 were identified in the Greenwood 138 kV TLA. These deficits are driven by immediate post contingency long-term emergency (LTE) limitations and can increase, depending on how the system is aligned at the time. To address the Greenwood 138 kV TLA needs, a load transfer from Bensonhurst No.2 splitting the Flatbush network and sending it to Gateway Park in 2030 will be planned as described in "Flatbush Network Split – Bensonhurst No.2 to Gateway Park".

The Greenwood 27kV Distribution Area Substation will require load relief beginning as soon as 2028, as seen in the table below.

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Greenwood (pre-transfer)										
Bay Ridge	250	259	267	272	276	278	281	283	286	288
Park Slope	214	216	217	217	218	218	219	220	220	221
Radial	23	24	24	24	24	25	25	25	25	25
Total Load	487	499	508	513	518	521	525	528	531	534
Electrification Adjustment	9	14	19	24	29	35	42	50	56	63
Other Adjustments	-8	-13	-16	-20	-20	-15	-17	-20	-20	-21
Net Load	488	500	511	517	527	541	550	558	567	576
Capability	511	511	511	511	511	511	511	511	511	511

Due to accelerated load growth, a number of load relief measures will be implemented to address the issue until the main solution can be constructed and executed - a load transfer to the new Industry City Area substation. To address Greenwood 27 kV Distribution Area Substation overloads, installation of additional transformer cooling will occur in 2028 for transformers no. 1, 2, 3 and 5 to achieve a 300-hr rating of 136 MVA, and through the emergent load relief program transformer 4 will be replaced and equipped with additional cooling to achieve a 300-hr rating of 136 MVA, all of which will add 26 MW of capability for a total of 537 MW. This increased station capability will address demand from 2028 to 2029. In 2030 the Company will transfer approximately 25 MW of radial load from Greenwood to Bensonhurst No. 2, followed by approximately 6 MW load transfer in 2032 and 9 MW load transfer in 2033 to Bensonhurst No. 2.

Greenwood (post-transfer)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Bay Ridge	250	259	267	272	276	278	281	277	271	193
Park Slope	214	216	217	217	218	218	219	220	220	221
Radial	23	24	24	24	24	0	0	0	0	0
Total Load	487	499	508	513	518	496	500	497	491	414
Electrification Adjustment	9	14	19	24	29	35	42	50	56	53
Other Adjustments	-8	-13	-16	-20	-20	-15	-17	-20	-20	-21
Net Load	488	500	511	517	527	516	525	527	527	446
Capability	511	511	511	511	511	511	511	511	511	511
Capability w/Transformer upgrades				537	537	537	537	537	537	537

The adjacent Bensonhurst No. 1 and No. 2 Area Substations have constrained 138 kV sub-transmission feeders beginning in 2032, furthermore the Greenwood 138 kV TLA deficits start in 2030, accelerating the need to move load out of Bensonhurst No. 1 and No. 2 load pocket. With these factors, transferring the approximately 80 MW load from Greenwood Area Substation to the adjacent Bensonhurst No. 1 and No. 2 load pocket would only result in overloads of the Bensonhurst 138 kV sub-transmission feeders.

These load relief measures will address load demand at the Greenwood 27 kV Distribution Area Substation, until Industry City 27 kV Distribution Area Substation is established and the Bay Ridge network split of approximately 80 MW can be executed in 2034. The establishment of the Industry City 27kV Distribution Area Substation will address future load growth needs in South Brooklyn, offering distribution benefits of shorter feeder runs and future feeder load relief reductions along with de-loading Greenwood 27k V Distribution Area Substation and the Greenwood 138 kV TLA.

Relationship to Broader Company Plans, Initiatives and the NYS Climate Leadership and Community Protection Act

The Company expects general increases in load, as well as electrification of vehicles and non-heating appliances. Load projections in the 2025 – 2034 Ten Year Pre-liminary Load Relief Program indicate that the Brooklyn networks will encounter increasing overloads in ensuing years, with the Greenwood 27 kV Distribution Area Substation exceeding its station design capability. To address reliability design criteria and build in resiliency for various contingency events, the new Sunset Park 345 kV Transmission Substation will be placed into service by 2034. This project will improve the reliability of the Bay Ridge and Park Slope Networks by allowing the Company to reduce network sizes and will establish feasible resiliency options for various contingency events, which are not available with the existing distribution system design. This new 345 kV transmission substation will also provide potential points of interconnection and for the connection of future distribution substations, such as the planned Industry City Area Substation.

By enabling load splits and smaller distribution networks in the Greenwood TLA, this project will progressively increase the reliability of the associated networks in both the near and long term and alleviate issues which limit the load capacity in the Greenwood 27 kV Distribution Area Substation. Once the project is in service, it will be more feasible to transfer out or partially restore the load emanating out of Greenwood 27 kV Distribution Area Substation, minimizing the impact of outages to customers. It will help the Company avoid public safety issues related to network failures and significant damage to Company equipment.

The Project will facilitate achievement of State and City emissions goals by facilitating electrification. The Project will enable 91 MW of capacity beginning in 2034 to account for future customer growth from both the Bay Ridge Network and the Park Slope Network for electric vehicle adaptation, electrification of hot water heaters, stovetops, ovens, and clothes dryers in the summer, and new

business. Over the long run, as electrification of heating becomes more mainstream, the Project will also enable the additional margin to support progress towards New York State's clean energy future goals. Accordingly, this Project will enable achievement of CLCPA goals, not just by enabling electrification, but because it will benefit disadvantaged communities through improved reliability. This aligns with Con Edison's strategic objective to meet economy-wide net-zero GHG emissions in our service territories by 2050.

The operational measures and system improvements implemented with this project would be sufficient in addressing load growth across Company networks in Brooklyn.

This project is a core investment that enables the Company to continue to provide safe and reliable service, even as the nature of the grid changes. This aligns with Con Edison's strategic objective of providing world-class safety, reliability, and security, while managing the equity challenges of the energy transition.

2. Supplemental Information

Alternatives

Alternative 1
Nevins Street Area Substation – This alternative was originally proposed to address the Greenwood 27 kV Distribution Area Substation overloads. This project has been determined to be suboptimal, as the station would be required to relieve overloads at Water Street in 2032 and Plymouth St in 2039, per the latest load forecasts. This alternative would require extending fourteen (14) Bay Ridge Network feeders by 4.5 miles, compared to the current solution which would move the area station closer to the load and reduce feeder extensions by 2 miles each, saving approximately $250 million in distribution feeder costs.

Alternative 2
Gowanus Substation Expansion – The original alternative to the Sunset Park 345kV Transmission Substations consisted of a conversion of the existing single-ring bus at Gowanus Substation into a double-ring bus configuration. This alternative would have created several new points-of-interconnection (POIs) and five transformers capable of supplying distribution area substations. This alternative would have been built on the same Company-owned McKeon Door property as the proposed Brooklyn Expansion and would have rearranged several 345 kV feeders to achieve a reliable topology between the two 345 kV rings of the Gowanus Substation.

The existing 138 kV feeders that supply Bensonhurst Substations 1 and 2 would have been transferred to and supplied from the expanded Gowanus Substation, offering load relief to Greenwood 138 kV Transmission Load Area.

Ultimately, the effort required to rearrange the existing feeders to achieve the desired level of topological reliability was deemed too risky in terms of potential outage scheduling issues and relocation costs.

Risk of No Action

Risk 1: Load Shedding

In the event the Greenwood 27 kV Distribution Area Substation becomes overloaded, load shedding may be required during peak load conditions in the Bay Ridge and Park Slope Networks, which could cause thousands of customers to experience service outages.

Non-Financial Benefits

- Provide necessary reliability and resiliency in an area of New York City that serves many critical loads (e.g., airports, transportation hubs, and hospitals) in a densely populated area where many buildings have elevators and various equipment loads.
- Provide transmission capacity to enable local growth and facilitate the integration of future bulk renewable energy sources.
- Create points of interconnection (POIs) on the transmission system that do not currently exist, which could be used by third party generators seeking to supply clean energy to the Con Edison and New York State Transmission Systems
- Provide POIs for energy storage.
- Improve the resiliency of the Bay Ridge, Park Slope and South Brooklyn (new) networks and prepare them for electrification. Instead of solving overloads by upgrading cable with lesser reliability improvements, this program will solve future primary overloads while greatly increasing the reliability of the network by introducing new feeders.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)
N/A

2. Major financial benefits
N/A

3. Basis for estimate
This estimate is based on an order of magnitude estimate of project costs based on a conceptual design and historical costs for similar scopes of work. High-level estimates of total costs, by primary spend category, are shown below, including escalation, overheads, and contingency.

	Estimated Direct Costs	Esc., OH, & Other Loading[1]	Estimated Total	% of Total
01-Labor	$ 76,096,123	$130,479,939	$206,576,062	15.9%
02-MSH	$272,982,771	$262,545,592	$535,528,363	41.1%
03-Cont Svcs	$251,105,143	$241,504,429	$492,609,572	37.8%
09-Other	$ 34,639,760	$ 33,315,349	$ 67,955,109	5.2%
Total	**$634,823,797**	**$667,845,309**	**$1,302,669,106**	

[1] Includes: Escalation (18%), CE OH (0%), A&S (2.5%), PT&P (39.35%), AFDC (24.73%), and Contingency (30%)

Project Risks and Mitigation Plan

Risk 1:
Delays due to resource/support coordination. There are a large number of projects to expand the electric distribution system that may strain existing resources.

Mitigation Plan 1:
Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts. Expand hiring and increase the number of employees over the next few years to be able to handle the increased flow of work.

Risk 2:

Material Availability Issues

Mitigation Plan 2:
Engineering will work with Supply Chain to establish a cohesive plan that aligns with vendor lead times. Stay engaged with vendors to ensure lead times are maintained, and adjust the plan as needed if shortages are encountered.

Risk 3:
One major risk is for load to increase faster than forecasted which will cause load to exceed equipment ratings before completion of projects to de-load such equipment.

Mitigation Plan 3:
Start projects early and on a longer cycle to allow for acceleration if the need arises.

Technical Evaluation / Analysis
Due to overload constraints identified in the Greenwood 138 kV Transmission Load Area, a new area substation would be the only viable alternative for load relief. Con Edison is proposing a 345kV transmission substation to supply a new 27kV indoor area substation, with a proposed in-service date of summer 2034 for both stations. The project aims to transfer approximately 80MW from the Bay Ridge Network to a newly formed South Brooklyn Network.

Project Relationships (if applicable)
As discussed above, the Brooklyn Expansion project is necessary for establishing a new Sunset Park Transmission Substation to supply the new Industry City Area Substation. A related distribution project involves a load transfer from the Greenwood Area Substation to the Industry City Area Substation along with a network split of the Bay Ridge Network and the creation of a new South Brooklyn Network. Close coordination will be maintained between these projects.

3. Funding Detail ($000)

Historic Spend

	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Test Year* (O&M Only)	Forecast 2024
O&M	$0	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	N/A	$0
Capital	$0	$0	$0	$628	N/A	$34,361

2025-2029 Request:
Total Request by Year:

	2025	2026 (RY1)	2027 (RY2)	2028 (RY3)	2029
O&M	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	$0
Capital (Total)	$0	$70,000	$100,000	$240,000	$150,000
Labor	$0	$10,020	$13,696	$32,852	$17,851
M&S	$0	$22,314	$30,501	$73,164	$39,755
Contract Svcs.	$0	$24,502	$33,492	$80,336	$43,653
Other	$0	$2,800	$3,828	$9,181	$4,989
Overheads	$0	$10,364	$18,483	$44,467	$43,752

*The test year runs from 10/1/2023 to 9/30/2024

Electric Operations / Distribution Engineering
2025-2029

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Brownsville No. 2 to Atlantic Area Substation-Richmond Hill (9B) to Ozone Park (11Q) Transfer	
Project/Program Manager: Frantz St. Phar	**Project/Program Number (Level 1):** 27901574
Status: ☒ **Initiation/Planning** ☐ **In-Progress (Projects Only)** ☐ **On-going (Programs Only)**	
Estimated Start Date: 2026	**Estimated Date In Service:** 2035
2025-2029 Funding Request ($000) **Capital:** $76,900 **O&M:** $0	

Work Description:

This project is part of a pair of projects planned to alleviate overloads on the 138kV feeders supplying the Brownsville transmission load pocket and to create capacity headroom in the Brownsville 2 Area Substation (BV2), both of which will reach their capacity to handle the customer loads by 2035. Under this project Con Edison is planning to de-load BV2 and its supply transmission feeders by transferring 242 MWs of load to the newly established Atlantic Area Station, or earlier since load increases are multi factor dependent and can vary depending on climate change, EV implementation and electrification efforts. Advancement of this work may be needed to avoid equipment overloads in the Brownsville transmission load area and BV2 Area station. Con Edison will accomplish this by creating a new network out of the eastern portion of the Richmond Hill (9B) network east of the geographical boundary of the Boroughs of Brooklyn and Queens. Con Edison would commence work in 2028 and be completed by 2035 or earlier depending on how the forecast develops. Due to the variability of the forecast, there is a strong possibility that the need to de-load the area station and BV2 will materialize much faster than predicted. Therefore, starting the planning and work early would allow us to accelerate the project to meet any overloads that may materialize earlier than expected.

BV2 supplies the Richmond Hill (9B) Network. The 9B load area is a 363 MW in 2025, 31 feeder electric distribution network with approximately 152,000 electric customers. 27 feeders supply network and non-network load while four 27kV feeders feed only non-network load. Con Edison is planning to de-load BV2 Area Station and its transmission feeders by splitting the 9B network into two separate load areas. The Brooklyn/Queens County boundary line is the best area to separate the load transferred to the new area station. There are very few secondary distribution network connections between both sides with most of the secondary network load being separated by non-network radial systems. This new boundary will greatly reduce construction costs and minimize disruption to our customers. The reinforcements on both sides of the lines will be minimized by choosing this cutline. All the electric load east of the county line (East of(E/O) Elderts Ln, E/O Drew St, E/O 75th Street will be transferred to the new Atlantic Area Station.

The current Richmond Hill grid east of the cutline will be split from the rest of the Richmond Hill network. The 9B portion west of the cutline will continue being supplied by BV2 and will still be known as the Richmond Hill Grid. The 9B portion east of the cutline will be supplied by the newly established Atlantic Avenue Substation. The new network will be named The Ozone Park Network. The new network will consist of 156 MWs of secondary network load east of the selected cutline, 54 MWs from the

wholesale transfer of the 4KV Richmond Hill complex and 32 MWs from the four non network feeders (9B91, 9B92, 9B93 and 9B94). The new network will also include all other non-network load: five Step Down (SD) Loops and three SD feeders as part of the 9B load to be transferred to the new Ozone Park Network. Forty-seven new feeders will be extended from the new station to supply the independent load pockets. The number of feeders is maximized to make sure that the different load pockets don't share the same feeders.

The new carved out network will be created by extending feeders from the newly created Atlantic Area station to predetermined pick up points in the current 9B feeders which extend east past the cutline. To increase reliability and to allow for maximum load growth potential, feeders will be extended from the new station to grab the different load pockets to have this pockets' feeder supply be independent from each other. Any reliability or load issue impacting these load pockets will then have no impact on each other. Instead of having feeders share the load of the different load pockets, the load will have its own segregated feeder supply. The plan then is to:

- Extend 23 feeders to pick up network load east of cutline. Sever any secondary ties between both side of the cutline. Install switch on the separation point or the pickup point of the 27KV feeder extension. The end effect is that we will have a new feeder extension from Atlantic Avenue picking a portion of a 27KV feeder feeding secondary distribution load east of the cutline. West of the cutline distribution load will still be fed by BV2 and Rich feeders. Total estimated load is 152 MWs.
- Extend ten feeders to pick the ten 4KV Unit Stations feeding the Richmond Hill 4KV complex. We then can disconnect the primary side feed from BV2 and have this load being fed exclusively from the new Atlantic Area station by dedicated feeders. Total load 54 MWs. Currently, 27KV feeders supply the 4kV grid and network load.
- Extend four feeders to pick up the non-network feeders (9B91, 9B92, 9B93 and 9B94). Approximate load is 36 MWs.

The new network will consist then of 37 feeders and 242 MWs of 2024 load and will be supplied by the new Atlantic Area SS. The now smaller more reliable Richmond Hill network will be supplied by 24 feeders from BV2 substation and will supply 121 MW of net load (based on projected net load in 2025) to the customers west of the cutline.

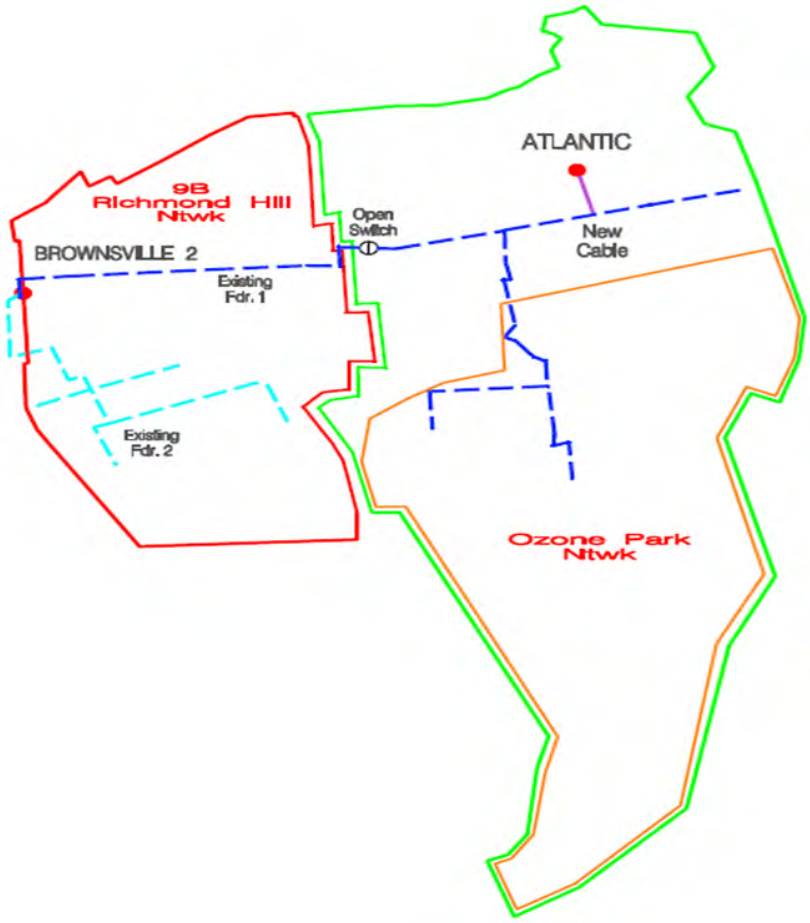


Figure 1. Richmond Hill network after cutover and establishment of Atlantic Station out of a portion of BV 2 to create The Ozone Park network. Green are the boundaries for the new Ozone Park Network, Red are the boundaries for the smaller 9B network. The new boundaries are represented by the red/green line.

Con Edison will be extending 1000 mcm cable from the new Atlantic Area Sub Station to the pick-up points near the cutline on the Brooklyn/Queens official boundary line. This cable extensions will be used to segregate and separate the load east of the cut line to be transferred to the new Area Station. This cable has ample capacity for future load growth.

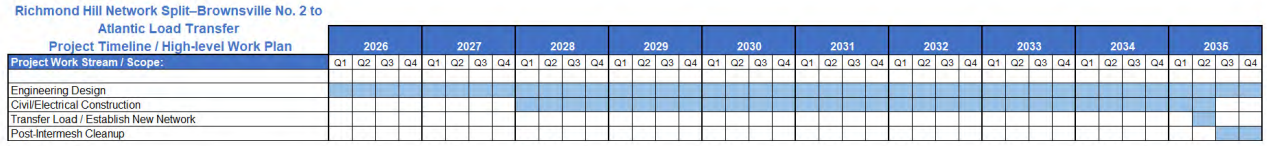
A prerequisite to this work is the establishment of the Atlantic Area station (formerly known as Gateway Park No. 2) which is a separate project. This station is a new indoor 27kV area substation that will be arranged in a double bus configuration with four 138kV/27kV transformer banks. The station will be supplied from the 345kV Brooklyn Energy Hub. This station will allow for added resiliency to the network and additional transmission capacity to mitigate deficiencies in the sub transmission feeders feeding BV1 and BV2. The project splits the Richmond Hill network by carving out 242 MW and creates a new 9B east of the B/Q boundary line. The property where the Atlantic Area station will be built is still under review and hasn't been purchased. The cost analysis and scope of construction is based on the property being on the intersection of Atlantic Ave and 102th street.

The scope of work involved in the establishment of the new Ozone Park Network are shown below and the timeline should take 6 years to implement:

Discipline	Name	Units
UG	120/208V Transformer	43
UG	Secondary Mains	300
UG	Street Ties (4 sets of 4-500)	44
UG	3-2/0 EPR (splicing included)	48
UG	3-1000 EPR (splicing included)	786
CM - Structure	M14	502
CM - Structure	M11-6	57
CM - Structure	Service Box	10
CM - Structure	V13-6	41
CM - Conduit	Roadway Conduit 6"	161,813
CM - Conduit	Roadway Conduit 4" & 5"	12000
UG	Vacuum Switches	37
UG	Cam-ops	37

Figure 2, Scope and high-level units of work involved in the split of the Richmond Hill Network. Area Station assumed to be near Atlantic Ave and 102nd street.

Engineering will begin in 2026 for this project, construction is expected to begin in 2028 and to be completed in 2035. The estimated timeline to complete the major scopes of work associated with the project is below. This timeline is subject to change at any time, as the Company optimizes the project schedule and incorporates impacts of other projects and system performance.



Justification Summary:
Con Edison delivers electricity to customers through transmission and distribution facilities. In general, a transmission substation supplies power to one or more distribution area substations, which in turn feed local electric networks that supply power to customers. The Brownsville Transmission load area feeds two area stations: Brownsville 1(BV1) and Brownsville 2(BV2). BV2 feeds the Richmond Hill Grid along with non-network feeder load. The target of this white paper is the split of the Richmond Hill network into two smaller networks. In 2034 the Richmond Hill network & radial is forecasted to reach a total of 480 MWs, 96% of the substation's capability and, given continued load growth, the station will meet or exceed its capability in 2036. This fast growth will also cause the combined load of BV1 and BV2 to exceed the rating of the sub-transmission feeders feeding the Brownsville load pocket by 2035. The sub-transmission feeders are listed below. The variability and unpredictability introduced by climate change, EV rate of deployment and electrification makes it likely that the exceedance of load over capacity may happen much sooner. Therefore, it is imperative that planning and construction starts by 2028 to allow the Company enough time to ramp up if the forecasts warrant it.

AREA SUBSTATION SUPPLY FEEDERS							
Transmission	AREA SUBSTATION	Feeder 1	Feeder 2	Feeder 3	Feeder 4	Feeder 5	Feeder 6
Farragut 345kV	Brownsville No. 1	38B01	38B02	38B03	38B04	38B05	
345kV	Brownsville No. 2	38B01T	38B02T	38B03T	38B04T	38B05T	

The current 20-Year Load Forecast shows a continuing upward trend of peak demand growth at the network level driven by increased building and transportation electrification that continues to drive the need for load relief at the area station and transmission supply feeder level to maintain reliability design criteria and to meet climate resiliency objectives. Based on the 2024 forecast, the BV1 and BV2 Stations electric distribution networks (Ridgewood-5B, Crown Heights-3B, Richmond Hill-9B and radial systems) have projected loads that will cause the Brownsville sub transmission load feeders and substation to exceed their capability by 2035. The main drivers to load growth in the long-term forecast are climate change adjustments that we use in our design model, new business increase, electric vehicles deployment, buildings moving to full electric heating and organic load growth. The Company has an active BQDM program consisting of utility-side and customer-side solutions for the Brownsville load pocket to provide peak load reductions that will help to mitigate projected supply feeder capability deficiencies. Additionally, in 2026 a 60 MW load transfer from Brownsville No.1 Ridgewood network to Glendale Area Substation, and a 120 MW load transfer from Brownsville No.1 Crown Heights network to Gateway Park Area Substation are planned to provide load relief to the Brownsville 138 kV sub-transmission feeders. The split of the Richmond Hill network will improve the reliability of all networks by reducing the network and feeder lengths and by decreasing the average load per feeder. In addition, it will de-load the overloaded transmission and substation equipment. See below load forecast for the Brownsville transmission load pocket and associated stations BV1 and BV2.

Based on the Load Forecast of November 19, 2024
Independent MW Area Peaks - Summer

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Brownsville No. 1												
Crown Heights	210	214	218	102	103	104	104	105	106	106	107	108
Ridgewood	221	165	166	169	169	171	172	172	173	174	175	175
Total Load	431	379	384	271	272	275	276	277	279	280	282	283
Electrification Adjustment	5	12	15	15	18	22	28	33	38	46	52	60
Other Adjustments	-7	-8	-8	-8	-7	-3	-4	-4	-3	-5	-4	-5
Net Load	429	383	391	278	283	294	300	306	314	321	330	338
Capability	523											
Brownsville No. 2												
Richmond Hill	330	341	348	354	358	360	363	365	367	369	371	373
Radial	34	34	34	35	35	36	36	36	36	37	37	37
Total Load	364	375	382	389	393	396	399	401	403	406	408	410
Electrification Adjustment	3	6	12	18	25	34	43	52	62	74	86	98
Other Adjustments	-4	-4	-5	-5	-3	1	1	1	1	0	0	0
Net Load	363	377	389	402	415	431	443	454	466	480	494	508
	501											
Brownsville Nos. 1 & 2 Load	792	760	780	680	698	725	743	760	780	801	824	846
Feeder Peak Diversity	0	0	-1	2	0	0	0	0	0	0	0	0
Utility Sided Solutions	-15	-20	-21	-19	-19	-20	-20	-20	-19	-19	-14	-14
Customer Sided Solutions	-1	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-1
Net Load	776	729	747	652	668	694	712	729	750	771	799	831
138 kV Feeder Capability	771	771	771	771	771	771	771	771	771	771	771	771
Feeder Capability @ 141 kV	788											
138 kV Feeder Loading	98%	95%	97%	85%	87%	90%	92%	95%	97%	100%	104%	108%
[S.N. Rating = 847 Amperes]												
Farragut Y-winding Load	776	729	747	652	668	694	712	729	750	771	799	831
Capability	908											
Farragut Y-winding Loading	85%	80%	82%	72%	74%	76%	78%	80%	83%	85%	88%	92%
[TR No.4 S.E. 300-Hr Rating = 1017 Amps]												

To address the forecasted exceedance, Con Edison plans to split the Richmond Hill Network into two separate networks, a smaller Richmond Hill Network and the new Ozone Park Network. Build the new Atlantic Distribution Area Substation to supply the Ozone Park Network and transfer 242 MW of load from the Brownsville 2 Distribution Area Substation to the new Atlantic Distribution Area Substation.

The plan is to de-load the sub-transmission by splitting the Richmond Hill (9B) network into two separate networks: 9B west of the Brooklyn/Queens boundary line which will keep its Richmond Hill name and still be supplied by BV2 and 9B East of the cutline which will be transferred to the newly established Atlantic (formerly known as Gateway Park 2) Area Substation and will be named the Ozone Park network. This should provide about 242 MWs of load relief to the Brownsville sub transmission load pocket, BV2 area station and to the Transmission 345 KV equipment at Farragut which is also forecasted to overload a few years after the sub transmission feeders. The new Ozone Park network will consist of forty-three feeders and 242 MWs of 2024 load. The new smaller Richmond Hill network will consist of twenty-four feeders and an approximate net load of 174 MW in 2035. This will provide desperately needed load

relief for the BV load pocket and allow for future load expansion. The number of feeders used to supply the new network has been maximized to allow for maximum load growth and reliability.

Based on the Load Forecast of November 19, 2024
Independent MW Area Peaks - Summer

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Brownsville No. 1												
Crown Heights	210	214	218	102	103	104	104	105	106	106	107	108
Ridgewood	221	165	166	169	169	171	172	172	173	174	175	175
Total Load	431	379	384	271	272	275	276	277	279	280	282	283
Electrification Adjustment	5	12	15	15	18	22	28	33	38	46	52	60
Other Adjustments	-7	-8	-8	-8	-7	-3	-4	-4	-3	-5	-4	-5
Net Load	429	383	391	278	283	294	300	306	314	321	330	338
Capability	523											
Brownsville No. 2												
Richmond Hill	330	341	348	354	358	360	363	365	367	369	141	142
Radial	34	34	34	35	35	36	36	36	36	37	0	0
Total Load	364	375	382	389	393	396	399	401	403	406	141	142
Electrification Adjustment	3	6	12	18	25	34	43	52	62	74	33	37
Other Adjustments	-4	-4	-5	-5	-3	1	1	1	1	0	0	0
Net Load	363	377	389	402	415	431	443	454	466	480	174	179
	501											
Brownsville Nos. 1 & 2 Load	792	760	780	680	698	725	743	760	780	801	504	517
Feeder Peak Diversity	0	0	-1	2	0	0	0	0	0	0	0	0
Utility Sided Solutions	-15	-20	-21	-19	-19	-20	-20	-20	-19	-19	-9	-9
Customer Sided Solutions	-1	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-1
Net Load	776	729	747	652	668	694	712	729	750	771	484	507
138 kV Feeder Capability	771	771	771	771	771	771	771	771	771	771	771	771
Feeder Capability @ 141 kV	788											
138 kV Feeder Loading	98%	95%	97%	85%	87%	90%	92%	95%	97%	100%	63%	66%
[S.N. Rating = 847 Amperes]												
Farragut Y-winding Load	776	729	747	652	668	694	712	729	750	771	484	507
Capability	908											
Farragut Y-winding Loading	85%	80%	82%	72%	74%	76%	78%	80%	83%	85%	53%	56%
[TR No.4 S.E. 300-Hr Rating = 1017 Amps]												

Due to the variability of the forecast, starting the distribution work early in BV2 will protect the system from earlier than expected overloads in both the sub transmission and the transmission equipment.

In addition to the organic growth of the forecast, new environmental and climate concerns are leading the city and state to promote electric heat and EV charging infrastructure that will increase load on the grid. This creates variability in the forecast which can result in the advancement of the need for load relief which is difficult to forecast so it is important that we start planning and construction to be able to ramp up if the load increases ahead of forecast. The implementation of Local Law 97, which mandates energy efficiency improvements and greenhouse gas emission limits in large commercial and residential properties, is expected to significantly increase the conversion to all-electric buildings. This law will likely result in a substantial rise in project volumes. Also, implementing NYC Local Law 154 is driving the electrification of heating and appliances for new construction. This is expected to increase the load on each new service versus historical standards. Electrification of transportation is also expected to increase throughout the rate case period. Customers requesting service with large loads, such as multifamily residential, retail, and large commercial are increasingly installing EV charging infrastructure. Increased

adoption and installation of light duty electric vehicle chargers in existing parking areas and in new buildings is expected to grow.

Relationship to Broader Company Plans, Initiatives and the NYS Climate Leadership and Community Protection Act

The Company expects general increases in load driven by electrification of vehicles and heating. The Brownsville sub transmission load pocket and the Brownsville 2 Area Station will encounter increasing loads in the future when load increases to the point where it will match capacity. To address reliability design criteria and build in resiliency for various contingency events, the new Atlantic Area Station substation will be placed into service by 2035. This project will improve the reliability of the Richmond Hill Network by allowing the Company to reduce network sizes and will establish feasible resiliency options for various contingency events, which are not available with the existing distribution system design. This project strengthens the Con Edison electric system in the areas served by these facilities, including service to disadvantaged communities. Disadvantaged communities and underserved communities will benefit from this project by allowing electrification and EV deployment due to the increased station capacity. It will allow cleaner, greener sources of energy with reduced pollution and cleaner air in the DAC areas. The Project will facilitate achievement of State and City emissions goals by facilitating electrification. The Project will enable 242 MW of future customer growth in the networks fed by the Brownsville transmission load pocket and about 100 MWs extra capacity in the new Ozone Park network. This will support the effort for electric vehicle adaptation, electrification of hot water heaters, stovetops, ovens, and clothes dryers in the summer, and new business. Over the long run, as electrification of heating becomes more mainstream, the Project will also enable the additional margin to support progress towards New York State's clean energy future goals. Accordingly, this Project will enable achievement of CLCPA goals, not just by enabling electrification, but because it will benefit disadvantaged communities through improved reliability.

By enabling load splits and smaller distribution networks, this program will progressively increase the reliability of the associated networks in both the near and long term. The Project will alleviate issues which limits the load capacity in the Brownsville 2, 27 kV Distribution Area Substations. Once the project is in service, it will be more feasible to transfer out or partially restore the load emanating out of adjacent Distribution Area Substations, minimizing the impact of outages to customers. It will help the Company avoid public safety issues related to network failures and significant damage to Company equipment.

The system improvements implemented with this project would be sufficient to address load growth across the networks supplied by the BV1 and BV2 Area stations: Ridgewood, Crown Heights, Richmond Hill and non-network loop load. It will satisfy reliability, resiliency, safety, and compliance regulations.

By enabling load splits and smaller networks, this program will increase the reliability of the associated networks in the near and long term. It will help the Company avoid public safety issues related to network failure, customer outages and significant damage to Company equipment. Also, it will protect customers from any issues related to network shutdown.

Resiliency plans: this program will help during problems in the transmission and/or substation that limits the load capacity in the Glendale, Water Street, Jamaica, Brownsville 1, Gateway Park 1 and Bensonhurst substations. Once this project is complete, it will be more feasible to transfer out or partially restore the load coming out of the area stations.

Richmond Hill is number 2 worst out of 64 in the network reliability rankings. This network ranking is bound to get worse. The increasing load forecast and accompanying increase in load per feeder and reduction in the margins between the load and the feeder capacity will worsen. The most economical and

feasible solution is to reduce the load per feeder which will occur when we split the network load. The plans proposed in this paper are synergistic and complementary to the Climate Change Implementation Plan. The reliability, resiliency and load relief improvements in this network are complementary and a necessary step to manage the climate risk imposed by global warming and electrification.

The Network Reliability index (NRI) is a measure of the potential for a given network to get into a state where a network can fail. This is due to cascading feeder failures, resulted from overload conditions of the adjacent feeders, transformers and secondary grid. The NRI is greatly improved when we create new feeders or when we reduce the load per feeder. By reducing the load per feeder in the Richmond Hill grid, we will be able to better rebalance the load amongst the existing feeders, which makes it a more reliable network.

Risk management at the distribution level. By virtue of ranking in the top worst 2 in NRI, with no expectations of being able to reduce this number meaningfully, the Richmond Hill network will be susceptible to network shutdown relative to most networks in the system. The consequences would be severe for the company and the public. Public safety, disruption of public transportation, severe damage to company equipment and customer outages would be the immediate consequences. PSC penalties, reputational damage, increased regulatory scrutiny and severe financial impact would be the consequences in the longer timeframe.

2. Supplemental Information

Alternatives

The Project is needed to maintain reliability for current Richmond Hill Network customers. No other alternatives would address the reliability needs. The peak design exceedance cannot be met through equipment uprates or a transfer of load to any adjoining distribution area substation, and Non-Wires Solutions and energy efficiency measures would be insufficient to provide a permanent solution.

The alternative solution is to transfer load out of the BV1 or BV2 area stations to nearby networks not part of the three networks being fed by the Brownsville sub transmission feeders. There is no additional capacity in the three nearby stations: Glendale, Brownsville and Brownsville 1 and Brownsville 2. Since there are no cubicles available to introduce new feeders, the transfer would require extending feeders and adding large amounts of load and equipment to existing feeders. This will require extensive expensive upgrades with no improvement in reliability and continuous worsening of the NRI of the receiving network. Capacity for growth will be extremely constrained and new Area stations would have to be built anyway to de-load the receiving area station.

Another alternative considered was to rely upon Customer Sided Solutions (CSS) such as energy efficiency programs to mitigate any future sub-transmission capacity deficiencies. Energy efficiency programs can provide cost-beneficial solutions across multiple customer segments by accelerating load relief through little-to-no cost energy efficient upgrades and may aid in the deferral of traditional solutions for multiple years. Based on the magnitude of load relief required to address the overload constraints under a limited time frame, it has been assessed that an energy efficiency program is not a viable option.

Reconductoring the sub transmission feeder is not feasible because of its cost, constructability and lack of benefits. This wouldn't increase the reliability of the networks, decrease the load per feeder, improve the NRI in the distribution grids or increase station resiliency.

Risk of No Action

An overload in the sub transmission feeders that feed BV1 and BV2 Area Stations is predicted to occur. Many of Con Edison's Brooklyn/Queens substations are near full capacity and do not offer the feasibility

of load transfer. In the event the area station overloads, load shedding may be required during peak conditions which would cause thousands of customers to encounter service outages.
Without pursuing the project, the Company networks will encounter the potential inability of maintaining reliable system power flow controls, system reliability and resiliency concerns and/or possible customer outages for an extended period during peak load condition.
Additionally, should the de-load of the sub transmission feeder be deemed necessary, and no action has been pursued, there may not be sufficient time available to de-load the sub transmission load pocket via the split of the Richmond Hill Network.

Non-Financial Benefits

The Company must pursue the load relief solution that provides the most capacity, can accommodate additional electrification and maintains reliability. This proposed project is the only solution that achieves these objectives.

This project will provide the necessary reliability and resiliency in an area of New York City that serves many critical loads and hospitals in a densely populated area where many buildings have elevators and various equipment loads. Relief of the sub transmission and the station will ensure continued reliable service to the Richmond Hill, Ridgewood and Crown Heights networks and will allow the sub transmission load pocket and station to maintain the area substation N-1 reliability design criteria for long term projected load growth in this area of Brooklyn and Queens. This Project will also provide future relief to the Brownsville sub transmission feeders supplying BV1 and BV2 which provide service to BV1 and BV2 Area stations. In addition, this will also provide load relief to transmission equipment at Farragut which is projected to overload sometime after 2035. Brownsville No. 2 27 kV Distribution Area Substation is constrained by the Farragut to Brownsville 138 kV sub-transmission feeders, which will require load relief in the 10-year planning horizon. The establishment of the Atlantic 27 kV Distribution Area Substation, to be supplied by four 138 kV feeders from the new 345 kV Brooklyn Clean Energy Hub, will provide relief for the Farragut to Brownsville 138 kV sub-transmission feeders.

The increased capacity in the sub-transmission feeders brought on by transferring load out of BV2 can minimize impact on customers during an area station event that limits station capacity. Resiliency options are not feasible in this load pocket without rolling blackouts and mobile stations requiring a time-intensive set-up. By introducing new area station capacity and splitting current networks into smaller load areas, the Company will be able to handle loss of station capacity during emergencies and its impact on customers. If capacity at Water Street, Brownsville, Glendale and Bensonhurst stations are compromised, loads can be swapped between stations via shunts, minimizing, or eliminating the need for load shedding during an event.

This project will also improve the resiliency of the Jamaica and Springfield Network and prepare them for electrification. Instead of solving overloads by upgrading cable with lesser reliability improvements, this program will solve future primary overloads while greatly increasing the reliability of the network by introducing new feeders.

Meeting New York's CLCPA goals will ultimately require the Company to build system capacity for an anticipated increase in load growth. With electrification of the City, as we move away from a carbon economy, we will require capacity in the affected networks to accommodate unprecedented load growth. Rapid load growth has the potential to leave the Company in a difficult position to address all the relief and reliability challenges in the near future. Customers will be satisfied with much less construction in the long term because the large number of overloads expected in the current system will be resolved with this project, at least for the Richmond Hill network. Otherwise, hundreds of sections will require load relief and excavation over the next few decades in different areas of this part of Brooklyn and Queens.
By decreasing the probability of a network shutdown, this program will increase the reliability and resiliency of the network in the long term. It will help the Company avoid public safety issues related to

network failure, customer outages and significant damage to company equipment. Also, it will shield the Company from any reputational issues related to network shutdown.

Feeders containing 4 kV stations that also supply a 27 kV secondary network are known to cause load shifts on the 27 kV grid as the load transfers to nearby feeders after feeder contingencies. The large 27 kV network load remaining in Jamaica will benefit from removing this risk factor. When a 27 kV feeder that is connected to the 4 kV grid fails, the load gets transferred via 4 kV interties to other 4 kV unit stations and their 27 kV supply feeders. Additionally, the secondary network redistributes the network load to other supplying feeders. This can cause substantial amounts of load to be transferred to related feeders. This sudden increase in load can stress the remaining in-service 27 kV feeders supplying the load area and cause feeders to trip during multiple contingency events. The new Ozone Park network will supply the 4KV load with its own 27 kV feeder supply independent of the secondary grid. This will reduce risk to both networks. There will be fewer customer disruptions. This project will also help reduce outages because less stress on the feeders and eliminate all major load relief projects that would otherwise be required.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)
N/A

2. Major financial benefits
A financial benefit of this work is also cost avoidance at the 27 KV feeder distribution level. As load increases, the margins between the feeder ratings and feeder loads will decrease in the network to the point where extensive load relief will be needed to upgrade feeder cable. The network will require an increasingly growing budget over the next decades to address feeder overloads with little benefit to the reliability of the network. As the load increases, feeders will reach and go beyond their rating. The standard way available to resolve the overload is to install new duct and replace the overloaded section. This is an expensive proposition. An uptick in the load forecast, for example caused by the electrification of cars and heating, can increase the number of feeders that need expensive load relief. The work proposed in this paper will stop any load relief work in the existing feeder for the foreseeable future.

Another cost savings is that the much lower load per feeder gained by introducing new ones will reduce the stress on all the feeders in the network during summer contingencies. Feeder failures increase in the summer as load increases and gets close to their rating.

3. Basis for estimate
The funding request is based on an initial order of magnitude estimate based on the scope of work and major equipment described above. The unit costing method was used to estimate the cost for the distribution system establishment of the Ozone Park network. The number of required units of equipment and material were identified and multiplied by a loaded unit cost that contains material, labor, escalation, overheads, and contingency. The initial scope of work was studied and specific units of work needed were obtained at a high level.

Name	Units	Total Unit Cost	Total Cost
120/208V Transformer	43	$26,535	$1,141,000
Secondary Mains	300	$26,993	$8,098,000
Street Ties (4 sets of 4-500)	44	$9,773	$430,000
3-2/0 EPR (splicing included)	48	$53,021	$2,545,000
3-1000 EPR (splicing included)	786	$203,024	$159,577,000

M14	502	$123,269	$61,881,000
M11-6	57	$60,298	$3,437,000
Service Box	10	$18,800	$188,000
V13-6	41	$125,220	$5,134,000
Roadway Conduit 6"	161,813	$1,397	$225,972,000
Roadway Conduit 4" & 5"	12,000	$977	$11,718,000
Vacuum Switches	37	$186,135	$6,887,000
Cam-ops	37	$72,432	$2,680,000
		Total	**$489,688,000**

Project Risks and Mitigation Plan

Risk 1:
Permitting by the city, Park departments, MTA & LIRR Interference, find lanes for ducts to be installed.

Mitigation Plan 1:
Identify issues early via surveys and engage stakeholders to get permits and find clear lanes.

Risk 2:
Interference with city contractors/paving coordination

Mitigation Plan 2:
Coordinate with city and DOT to get access and schedule work to avoid conflicts.

Risk 3:
Crossing major roadways and parks.

Mitigation Plan 3:
Avoid crossings by rerouting. If not possible engage early to find different construction techniques like boring to cross major roadways, train lanes and park if possible. Place area station closer to the load to be transferred to avoid difficult crossings.

Risk 4:
Delays due to resource/support coordination. There are a large number of projects to expand the electric distribution system that may strain existing resources.

Mitigation plan 4:
Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts. Expand hiring and increase the number of employees over the next few years to be able to handle the increased flow of work.

Risk 5:
Material Availability Issues

Mitigation plan 5:
Engineering will work with Supply Chain to establish a cohesive plan that aligns with vendor lead times. Stay engaged with vendors to ensure lead times are maintained, and adjust the plan as needed if shortages are encountered.

Risk 6:

One major risk is for load to increase faster than forecasted which will cause load to exceed equipment ratings before completion of projects to de-load such equipment.

Mitigation Plan 6:
Start projects early and on a longer cycle to allow for acceleration if the need arises.

Technical Evaluation / Analysis
Area Station planning analyzes forecast and equipment rating and estimates when equipment will exceed its rating.

Project Relationships (if applicable)
The new Area station named Atlantic station would need to be built to receive the split load from Brownsville 2.

3. Funding Detail ($000)

Historic Spend

	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Test Year* (O&M Only)	Forecast 2024
O&M	$0	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	N/A	$0
Capital	$0	$0	$0	$0	N/A	$0

2025-2029 Request:
Total Request by Year:

	2025	2026 (RY1)	2027 (RY2)	2028 (RY3)	2029
O&M	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	$0
Capital (Total)	$0	$0	$0	$12,300	$64,600
Labor	$0	$0	$0	$1,594	$8,374
M&S	$0	$0	$0	$3,265	$17,150
Contract Svcs.	$0	$0	$0	$4,426	$23,246
Other	$0	$0	$0	$684	$3,594
Overheads	$0	$0	$0	$2,330	$12,236

*The test year runs from 10/1/2023 to 9/30/2024

Electric Operations / Distribution Engineering

2025-2029

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Corona No. 1 to Hillside No. 1 Transfer	
Project/Program Manager: Frantz St. Phar	**Project/Program Number (Level 1):** 27719605
Status: ☒ **Initiation/Planning** ☐ **In-Progress (Projects Only)** ☐ **On-going (Programs Only)**	
Estimated Start Date: 2027	**Estimated Date In Service:** 2033
2025-2029 Funding Request ($000) **Capital:** $219,759 **O&M:** $0	

Work Description:

The Company's 2024 Forecast projects Corona No.1 Area Substation to be overloaded beginning in 2032. To relieve this forecast load constraint, Con Edison is planning to split the Flushing (7Q) network and non-network(radial load) currently served by the Corona No. 1 Area Substation into two separate load areas, a smaller Flushing network that continues to be served by Corona No. 1 and a new network (Bayside) to be served by a new Hillside Area Substation (Con Edison is still finalizing the exact location where the Hillside Area Substation will be located, so in order to develop design this project Con Edison assumed this substation will be located at 42nd Avenue and 172nd Street). Under this project Con Edison plans to split the current Flushing network while a separate project establishes the new Hillside Area Substation (See the Establish Hillside Area Substation white paper).
Corona No.1 Area Substation has a net load of 398 MW, with the Flushing (7Q) network having 28 network feeders and 2 non-network feeders with approximately 130,000 electric customers. Once Con Edison splits the network, the northern portion of the current 7Q network will be served by the new Hillside Area Station while the southern portion remains in the Flushing network supplied by Corona No. 1.

Con Edison's Flushing network consists of four clearly segregable load areas. The southern and western portions of the network are comprised of secondary distribution networks. The center east and northern portions have non-network distribution systems with some small pockets of embedded secondary network. The load areas Con Edison is targeting to create the new network to take advantage of the natural separations that currently exist and include the Flushing 4KV grid, the Flushing multibank, four autoloops, and some small pockets of embedded secondary network inside the larger non-network load areas. The four main systems comprising the current 7Q network are independent (i.e., not connected at the distribution level) but share primary feeders supplying them from Corona No. 1.

New feeders from the new Hillside Area Station will be extended to strategic points to pick up the feeders supplying the three non-network radial systems which are located mostly in the central, north, and east side of the network east of Bell Blvd & North of 33 Ave. Any primary feeder connections from Corona will then be severed and this load will then be fed from the new Hillside substation and will be referred to as the Bayside network. The Hillside Area Substation will supply the new Bayside network

that will be established from the approximately 150 MW load split from Flushing network load and 28 MW Radial load in 2033. Due to the feasibility of constructing Hillside and executing load transfers, the earliest date is 2033, although the need date is 2032. Load relief solutions to address the 2032 deficit are being evaluated.[=

The now much smaller, more reliable Flushing network will continue to be supplied by the Corona No. 1 Area Substation through the existing 28 network feeders.

To supply the new Bayside network, Con Edison will extend 24 feeders from the newly established Hillside station to the load area being segregated. The project will maximize the use of the new feeders to increase reliability and allow for load growth. Sixteen (16) feeders will be used to supply the 4 KV grid and small embedded network load, four (4) feeders will supply the Flushing multibank, and four (4) feeders will supply the four (4) autoloops.

Con Edison will install 1000 mcm cable from Hillside to the pick-up points just south and west of the future boundaries of the two networks. Figure 1, below, shows the way the new feeders will run to pick up the load being dropped from the Flushing Network.

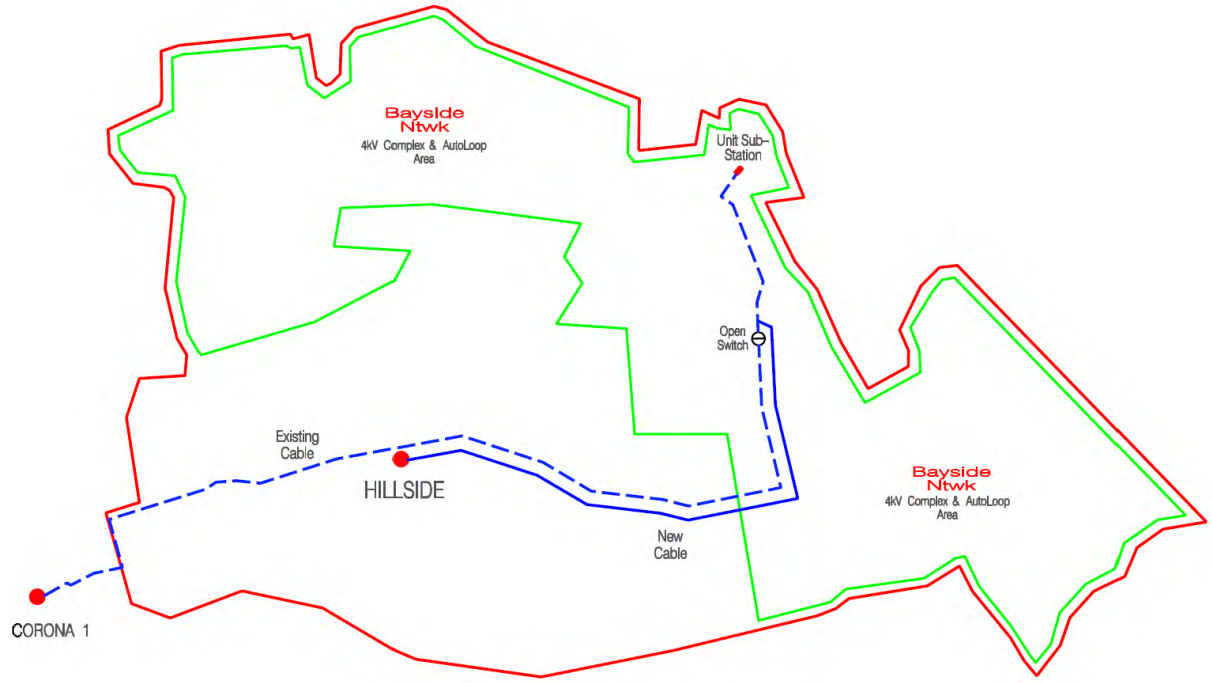


Figure 1. Overall feeder run from Hillside and Corona 1 stations showing how the new Hillside feeders will pick up the load to create the new Bayside Network.

A prerequisite to this work is the establishment of the new Hillside Area station which is a separate project. This station is a new indoor 27kV area substation that will be arranged in a double SYN bus configuration with four 93.3 MVA 138kV/27kV transformer banks and 30 MVAR capacitor. The station will be supplied from the new 345kV Eastern Queens switching station. This station will allow for added resiliency to the network and additional transmission capacity to mitigate deficiencies in the Jamaica load pocket as well.

The primary scopes of work involved in the establishment of the new Bayside Network are shown below:

- Install or replace 316,468 trench feet of conduit.
- Install or replace 1,436 sections of primary cable.

- Install or replace 300 sections of secondary cable.
- Install or replace 30 120/208V transformers.
- Install or replace 1,043 underground manholes/vaults.
- Install or replace 9 service structures.

Major or long-lead equipment requirements for the project include, but are not limited to:

Major Equipment Type	Number to be Purchased
120/208V Transformers	30
Roadway Conduit 6" (1 Unit = 100 LF)	3,045
Roadway Conduit 4" & 5" (1 Unit = 100 LF)	120
Secondary Mains (sections, 250-ft each)	300
3-2/0 EPR (splicing included) (sections, 250-ft each)	35
3-500 EPR (splicing included) (sections, 250-ft each)	48
3-1000 EPR (splicing included) (sections, 250-ft each)	1,353
Manholes	1,015
Vaults	28
Service Boxes	9
Vacuum Switches w/SCADA	24
Cam-Op Disconnect Switches	24

Engineering and long lead equipment procurement will begin in 2027 for this project and construction is expected to begin in 2029 and to be completed in 2033. The estimated, high-level timeline is below. This timeline is subject to change at any time, as the Company optimizes the project schedule and incorporates impacts of other projects and system performance.

Justification Summary:

Con Edison forecasts the Corona No.1 Area Substation will meet and exceed its capacity based on The Company's 2024 Load Forecast in 2032. Due to timeline constraints, the earliest the Company can get Hillside Area Substation in-service is 2033, therefore the company will execute the load transfer from Corona No.1 to Hillside in 2033, and a load relief solution to address the 2032 overload is being evaluated. Con Edison plans to split the Flushing network into two smaller networks in order to de-load Corona No.1 under this project.

Con Edison's current 20-Year Load Forecast shows an enduring upward trend of peak demand growth at the network level driven by increased building and transportation electrification that continues to drive the need for load relief at the area station and transmission supply feeder level to maintain reliability design criteria and to meet climate resiliency objectives. The main drivers to load growth in the long-term forecast are climate change adjustments that we use in our design model, new business increase, electric vehicles deployment, buildings moving to full electric heating and organic load growth. The split of the Flushing network will improve the reliability of all networks by reducing the network sizes and de-load the overloaded substation equipment. See below load forecast for Corona No. 1.

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Corona No. 1																				
Flushing	376	389	408	430	434	437	439	441	443	445	447	449	451	453	454	456	458	459	460	462
Radial	25	25	25	26	26	27	27	27	28	28	28	29	29	29	29	30	30	30	31	31
Total Load	401	414	433	456	460	464	466	468	471	473	475	478	480	482	483	486	488	489	491	493
Electrification Adjustment	5	9	16	21	29	38	47	57	68	80	93	105	118	131	144	158	171	185	198	212
Other Adjustments	-8	-10	-13	-15	-15	-11	-11	-11	-12	-13	-13	-13	-14	-15	-15	-16	-17	-18	-18	-20
Net Load	398	413	436	462	474	491	502	514	527	540	555	570	584	598	612	628	642	656	671	685
Capability	511																			
deficits								3	16	29	44	59	73	87	101	117	131	145	160	174

The plan is to de-load the Corona No. 1 by splitting the Flushing(7Q) network into two separate networks: The new Bayside network encompassing all the non-network load north and east of the current Flushing network will be transferred to the newly established Hillside Area Station.

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Corona No. 1																				
Flushing	376	389	408	430	434	437	439	441	293	294	296	297	298	300	300	302	303	304	304	306
Radial	25	25	25	26	26	27	27	27	0	0	0	0	0	0	0	0	0	0	0	0
Total Load	401	414	433	456	460	464	466	468	293	294	296	297	298	300	300	302	303	304	304	306
Electrification Adjustment	5	9	16	21	29	38	47	57	45	53	62	69	78	87	95	105	113	122	131	140
Other Adjustments	-8	-10	-13	-15	-15	-11	-11	-11	-8	-9	-9	-8	-9	-10	-10	-11	-11	-12	-12	-13
Net Load	398	413	436	462	474	491	502	514	330	338	349	358	367	377	385	396	405	414	423	433
Capability	511							TBD												

Relationship to Broader Company Plans, Initiatives and the NYS Climate Leadership and Community Protection Act

This project will not directly impact greenhouse gas emissions.

This project strengthens the Con Edison electric system in the areas served by these facilities, including service to disadvantaged communities.

This project is a core investment that enables the Company to continue to provide safe and reliable service, even as the nature of the grid changes. This aligns with Con Edison's strategic objective of providing world-class safety, reliability, and security, while managing the equity challenges of the energy transition.

This project supports the State's achievement of CLCPA and clean energy goals. This aligns with Con Edison's strategic objective to meet economy-wide net-zero GHG emissions in our service territories by 2050.

2. Supplemental Information

Alternatives

The alternative solution is to transfer the load out of Corona No. 1 area station to nearby networks. There is no additional capacity in the nearby area substations, including Corona No. 2 and Glendale to support load transfer from Corona No. 1. In any case, the amount that could be transferred out is limited by natural and manmade barriers.

Risk of No Action

An overload in Corona 1 is predicted to occur. Many of Con Edison's Brooklyn/Queens substations are near full capacity and do not offer the feasibility of load transfer. In the event the area station overloads, load shedding may be required during peak conditions which would cause thousands of customers to encounter service outages.

Without pursuing the project, the Company networks will encounter the potential inability of maintaining reliable system power flow controls, system reliability and resiliency concerns and/or possible customer outages for an extended period during peak load condition.

Additionally, should the de-load of Corona No.1 be deemed necessary, and no action has been pursued, there may not be sufficient time available to de-load the Corona No.1 station via the split of the Flushing Network.

Non-Financial Benefits

The Company expects general increases in load, as well as electrification of vehicles and heating. The Flushing network and its supply area station Corona No.1 will encounter increasing loads in the future to the point where it will match and then exceed its capacity. To address reliability design criteria and build in resiliency for various contingency events, the new Hillside substation will be placed into service by 2033 to de-load Corona No. 1. This project will improve the reliability of the Corona No. 1 network by allowing the Company to reduce network sizes and will establish feasible resiliency options for various contingency events, which are not available with the existing distribution system design. Disadvantaged communities and underserved communities will benefit from this project by allowing electrification and EV deployment due to the increased station capacity. It will allow cleaner, greener sources of energy with reduced pollution and cleaner air in the DAC areas. The Project will facilitate achievement of State and City emissions goals by facilitating electrification. The Project will create headroom for future customer growth in the network fed by Corona No. 1. Hillside will be established with 358 MWs of capacity, much less than the load transferred from Corona No.1 to create the Bayside network. Therefore, creating ample capacity for load growth in the Bayside Network and by allowing future load transfers from Corona No.2 and thereby creating capacity in the networks fed by Corona No. 2. This will support the effort for electric vehicle adaptation, electrification of hot water heaters, stovetops, ovens, and clothes dryers, and new business. Over the long run, as electrification of heating becomes more mainstream, the project will also enable the additional margin to support progress towards New York State's clean energy future goals. Accordingly, this Project will enable achievement of CLCPA goals, not just by enabling electrification, but because it will benefit disadvantaged communities through improved reliability.

The system improvements implemented with this project would be sufficient to address load growth across the networks supplied by the Corona No.1 and Corona No.2 Area stations: Flushing, Jackson Heights and Rego Park. Corona No. 2 networks will benefit because a load transfer to Hillside is planned in the future in order to de-load Corona No.2. This will satisfy reliability, resiliency, safety, and compliance regulations.

By enabling load splits and smaller networks this program will progressively increase the reliability of the associated networks in both the near and long term. It will help the Company avoid public safety issues related to network failure, customer outages and significant damage to company equipment. Also, it will protect customers from any issues related to network shutdown.

Resiliency plans: this program will help during problems in the transmission and/or substation that limits the load capacity in the Corona No. 1 and Glendale substations. Once this project is complete, it will be more feasible to transfer out or partially restore the load coming out of the area stations.

Flushing is ranked as the number 5 worst network out of 64 in the network reliability rankings. This network ranking is expected to get worse with time. The increasing load forecast, accompanying increase in load per feeder, reduction in the margins between the load and the feeder capacity and aging of equipment will worsen the reliability of the network. Reducing load per feeder, creating new feeders, and reducing the length of feeders are known ways to improve the reliability of the network and improve the NRI. The most economical and feasible solution is to reduce the load per feeder which will occur when we split the network load. The plan proposed in this paper are synergistic and complementary to the Climate Change Implementation Plan. The reliability, resiliency and load relief

improvements in this network are complementary and a necessary step to manage the climate risk imposed by global warming and electrification.

An added benefit to the work proposed in this white paper is that, as New York State continues its efforts to reduce greenhouse gas emissions, further electrification of the economy will challenge the secondary distribution system. Reducing the load will decrease the load per feeder and transformers.

Risk management at the distribution level. By virtue of ranking in the top 5 worst in the network reliability Index (NRI), with no expectations of being able to reduce this number meaningfully, the Flushing network will be susceptible to network shutdown relative to most networks in the system. The consequences would be severe for the Company and the public. Public safety, disruption of public transportation, severe damage to Company equipment and customer outages would be the immediate consequences. PSC penalties, reputational damage, increased regulatory scrutiny and severe financial impact would be the consequences in the longer timeframe.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)
N/A

2. Major financial benefits
N/A

3. Basis for estimate
The funding request is based on an initial order of magnitude estimate based on the scope of work and major equipment described above. The unit costing method was used to estimate the cost for the distribution system establishment of the Bayside network. The number of required units of equipment and material were identified and multiplied by a loaded unit cost that contains material, labor, escalation, overheads, and contingency. The initial scope of work was studied and specific units of work needed were obtained at a high level.

Name	Units	Total Unit Cost	Total Cost
120/208V Transformer	30	$33,333	$1,000,000
Secondary Mains	300	$26,667	$8,000,000
Street Ties (4 sets of 4-500)	44	$9,773	$430,000
3-2/0 EPR (splicing included)	35	$57,143	$2,000,000
3-500 EPR (splicing included)	48	$62,500	$3,000,000
3-1000 EPR (splicing included)	1353	$203,252	$275,000,000
M14	991	$123,108	$122,000,000
M11-6	24	$41,667	$1,000,000
Service Box	9	$18,778	$169,000
V13-6	28	$142,857	$4,000,000
Roadway Conduit 6"	304,468	$1,396	$425,000,000
Roadway Conduit 4" & 5"	12,000	$1,000	$12,000,000
Vacuum Switches	24	$166,667	$4,000,000
Cam-ops	24	$83,333	$2,000,000
	Sum =		**$860,000,000**

Project Risks and Mitigation Plan

Risk 1:

The project is likely to require multiple permits from various New York City agencies, permit processes could lead to delays. In addition existing New York City, MTA, and LIRR infrastructure along planned routes needs to be identified and could lead to design changes or modifications, which could also result in project delays.

Mitigation Plan 1: Identify issues early via surveys and engage stakeholders to get permits and find clear lanes.

Risk 2:

Interference with city contractors/paving coordination

Mitigation Plan 2:

Coordinate with New York City agencies including NYCDOT to get access and schedule work to avoid conflicts.

Risk 3:

Crossing major roadways and parks will require coordination and special design consideration with responsible government agencies.

Mitigation Plan 3:

Avoid crossings by rerouting. If not possible engage stakeholders early to plan alternative construction techniques, such as boring to cross major roadways, train lanes and park if possible. Evaluate Area Station siting and feeder routing considerations to avoid difficult crossings.

Risk 4:

Delays due resource/support coordination. There are a large number of projects to expand the electric distribution system that may strain existing resources.

Mitigation plan 4:

Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts. Expand hiring and increase the staffing to appropriate levels to support the increased work scale.

Risk 5:

Material Availability Issues

Mitigation plan 5:

Engineering will work with Supply Chain to establish a cohesive plan that aligns with vendor lead times. Stay engaged with vendors to ensure lead times are maintained, and adjust the plan as needed if shortages are encountered.

Risk 6:

One major risk is for load to increase faster than forecasted which will cause load to exceed equipment ratings before completion of projects to de-load such equipment.

Mitigation Plan 6:

Start projects early and on a longer cycle to allow for acceleration if the need arises.

Technical Evaluation / Analysis N/A
Project Relationships (if applicable) As described in the Work Description section above, this project is only one part of the work needed to transfer load from the Corona No. 1 Area Substation and relieve the potential station overload in 2033. To make the load transfer described above, a new Area Substation must also be constructed, the Hillside station. These projects will be closely coordinated to ensure that the overall load relief solution is in place by 2033.

3. Funding Detail ($000)

Historic Spend

	Actual 2020	Actual 2021	Actual 2022	Actual 2023	Test Year* (O&M Only)	Forecast 2024
O&M	$0	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	N/A	$0
Capital	$0	$0	$0	$0	N/A	$0

2025-2029 Request:
Total Request by Year:

	2025	2026 (RY1)	2027 (RY2)	2028 (RY3)	2029
O&M	$0	$0	$0	$0	$0
Regulatory Asset	$0	$0	$0	$0	$0
Capital (Total)	$0	$0	$10,000	$19,500	$190,200
Labor	$0	$0	$$1,296	$2,528	$24,655
M&S	$0	$0	$2,655	$5,177	$50,493
Contract Svcs.	$0	$0	$3,598	$7,017	$68,442
Other	$0	$0	$556	$1,085	$10,583
Overheads	$0	$0	$1,894	$3,693	$36,026

*The test year runs from 10/1/2023 to 9/30/2024