Marginal Electricity Delivery Service Cost Study

New York State Electric & Gas Corporation and Rochester Electric and Gas Corporation

Prepared for Avangrid

June 30, 2025

Amparo Nieto

Principal

CRA Charles River Associates

TABLE OF CONTENTS

1 INTRODUCTION

Avangrid retained Charles River Project (“CRA”) to conduct a marginal cost of service (MCOS) study for the New York State Electric and Gas Corporation (“NYSEG”) and Rochester Gas and Electric Corporation (“RG&E” and together with NYSEG, the “Companies” and individually, the “Company”). In August 2024, the Commission issued an Order (“the August Order”) requesting the Companies to file MCOS study updates to be filed along with the Companies’ Distributed System Implementation Plans (“DSIP”). [1] The MCOS studies are intended to support and advance the objectives of New York’s Reforming the Energy Vision (“REV”) proceeding. Currently, the MCOS study results inform the Value of Distributed Energy Resources (“VDER”) within the Value Stack proceeding (commonly referred to as “the MCOS proceeding”).[2]

CRA has developed a MCOS study for each of the two Companies, consistent with the Commission’s overall methodological guidelines as per the Order. The studies produce a long-term view of system-wide marginal cost estimates associated with the cost of meeting peak load growth, separately estimated for the upstream and the lower voltage delivery system, through the next 10-year planning period (2026-2035).

This report provides more details on the approach that CRA has followed to estimate marginal costs for each component of the service and presents a summary of the results for each Company. The report is organized as follows:

- Section II describes the context of the study.
- Section III summarizes the study approach, and any assumptions that were made in developing the study if needed to supplement available information.
- Section III reviews findings of results and implications for each area of the Companies’ distribution service, as well as the importance of considering areas of the system that may not need to expand the facilities.
- Section IV reviews time-differentiation of the resulting marginal costs for consideration in future evaluations of marginal cost-based compensation of injections to the grid.

[1] Case 19-E-0283, Proceeding on Motion of the Commission to Examine Utilities’ marginal Cost of Service Studes, *Order Addressing Marginal Cost of Service Studies* (issued August 19, 2024).

[2] Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources, *Order Regarding Value Stack Compensation* (issued April 18, 2019) (Value Stack Compensation Order).

2 CONTEXT AND OBJECTIVES OF THE STUDY

A MCOS study offers valuable information on the expected on-going cost of providing delivery service to accommodate expected changes in demand due to organic growth, economic development, and DERs, at different times of day and voltage levels. The Companies' service territories are experiencing increasing customer adoption of renewable distributed generation ("DG"), electric vehicles ("EVs"), and energy storage, coupled with expectations of significant growth in building electrification through air source heat pumps. The combination of these changes, along with energy efficiency ("EE") programs, has a significant impact on the patterns of the hourly load profile and peak demands that the transmission and distribution grid must accommodate system-wide and at any given location. The Companies anticipate a continuous decline in summer peak load in the near term, and a significant acceleration in winter peak load growth longer term, consistent with NYISO projections for the state. In this context, the Commission directed the utilities to update their MCOS studies and ensure that they are consistent with a long-term view of system-wide capacity conditions.

MCOS study results, when used to establish price signals for electricity imports from the grid or compensation of injections of power may have beneficial outcomes. They are helpful to: (a) incentivize customers to use the grid efficiently, i.e., only when the customer values electricity more than the marginal cost of providing the service; and (b) contribute to an efficient pace of DER adoption, since the distribution value that DER can effectively provide to the system is monetized and reflects how changes in demand affects the way the Company plans and operates its system.

To be fully effective towards these goals, price signals would ideally be temporal (differentiated by time of day) and locational. The MCOS studies prepared and summarized in the context of this docket are built on information of planned capacity expansion investments at the substation and feeder level with individually calculated costs and MVA of capacity gains at each location. The information is then aggregated and averaged at the system level.

3 CONFIGURATION OF THE COMPANIES' GRID

The starting point for a MCOS study is identifying the relevant segments of the Company's local transmission and distribution grid system. In the Companies' MCOS studies, investments were categorized into four cost components, i.e., High-voltage upstream line, Upstream substation, Distribution substation, and Primary circuits. The voltage levels for each segment are as follows:

1) Upstream (a.k.a. transmission)[3] which for purposes of this study includes the following:

[3] The Companies refer to this segment of the grid as transmission. The MCOS study refers to these upstream substations and lines as "upstream" distribution, to differentiate them from the more regional transmission grid costs that are recoverable through NYISO Transmission Service Charges (TSCs).

- Substations that are fed from the 115kV system and convert power to either 69kV or 46kV or 34.5kV

- Feeders at 115 kV, 46 kV and 34.5kV that feed lower voltage distribution substations.

2) Lower voltage primary distribution grid, which includes:

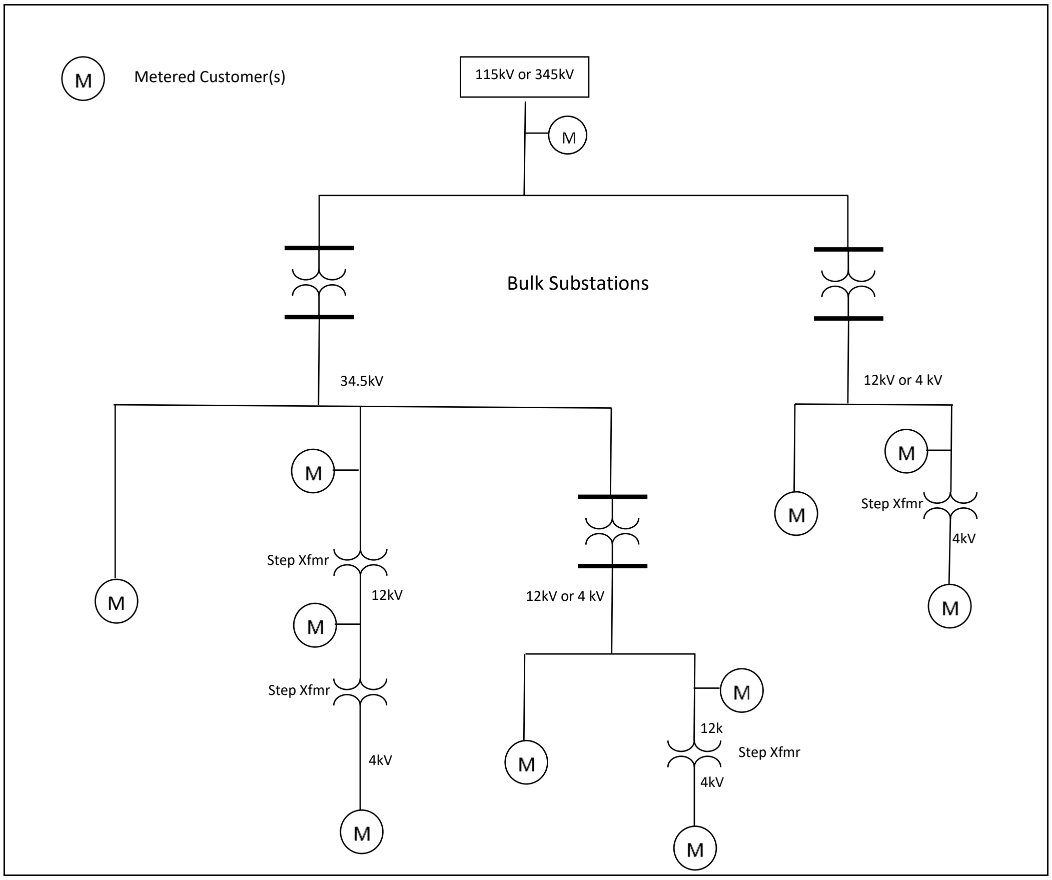
   - Distribution substations that convert power directly from 115 kV or the 34.5 kV systems to 12.47 kV or 4.6 kV.
   - Trunk-line primary distribution feeders, that start at the substation until the line branches to create a primary tap. These circuits typically operate at 12.47 kV or 4.6 kV; both Companies are in the process of converting 4.6 kV to 12.47 kV.

3) Local distribution facilities that connect the customer premises to the grid, which include the local primary taps[4] that serve localized loads, secondary line transformers, and secondary lines. The cost driver of those facilities are customer connections, rather than a forecast of diversified peak demand, and therefore are specific to customer local long-term needs.

Figure 5 shows a simplified diagram of the Companies' electric delivery system.

Figure 5. Electricity Delivery System Configuration

[4] These primary circuits typically are covered under the line extension policy. Distribution line extension costs represent the cost of extending a primary distribution line to connect a new customer remote from the grid. It is typically funded by the customer and is not considered a system-wide cost, rather a per-customer cost.



4 TREND OF GROWTH AND INVESTMENT NEEDS

Figures 1 through 4 below reflect the extent that investment needs are expected to change to meet winter and summer peak load growth to avoid violating the capacity requirement standard during normal conditions (N-0 violations) over the study period, i.e., before considering other (multi-value) investments. Currently the summer peaks drive most of the grid peak-load related capacity investment due to the lower carrying capability of the system in the hotter months. However, the Companies expect the grid to experience declining summer peak loads in upcoming years, for example NYSEG summer distribution peak loads in 2031 are expected to be about 7 percent lower than the 2024 peak summer loads. Winter peak loads are expected to grow every year, particularly after 2029, leading to about 6.6 percent of total growth by 2031 and about 18 percent in 2035, as transportation and building electrification becomes more prevalent.

Winter peak loads will increasingly be responsible for capacity-related investments in both Companies on the second half of the study period. The number of units with N-0 summer season capacity violations are expected to decrease consistently throughout the entire 10-year period for NYSEG. RG&E has more summer-peaking substations than NYSEG and higher summer peak loads, but will begin to expand substation and feeder capacity due to both summer and peak winter loads after 2031.

Figure 1. Winter Capacity Needs, Substation and circuits expected to incur in N-0 violations, as a percent of total service area, NYSEG

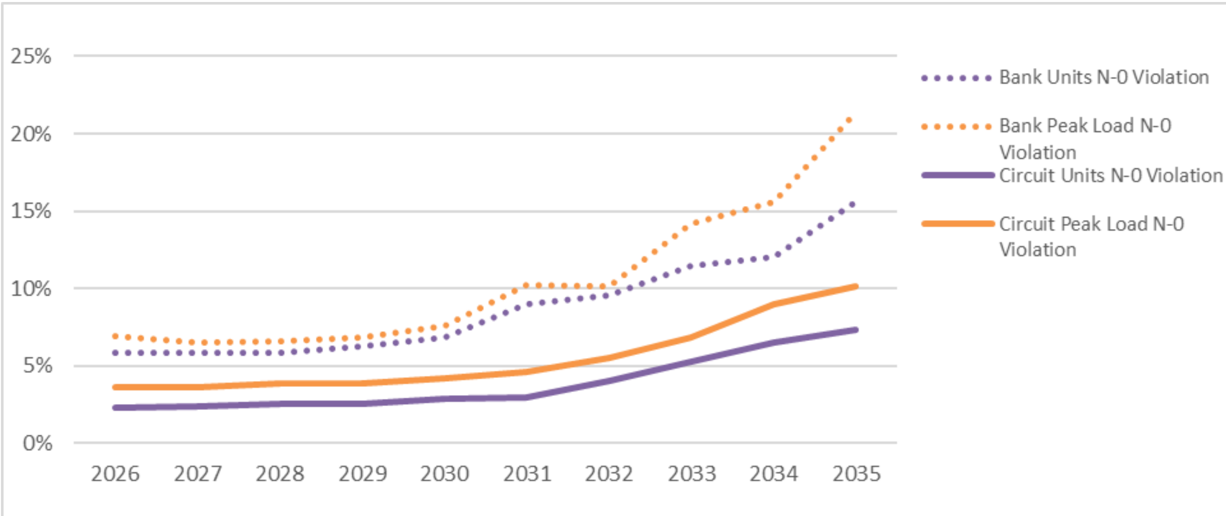


Figure 2. Winter Capacity Needs, Substation and circuits expected to incur in N-0 violations, as a percent of total service area, RG&E

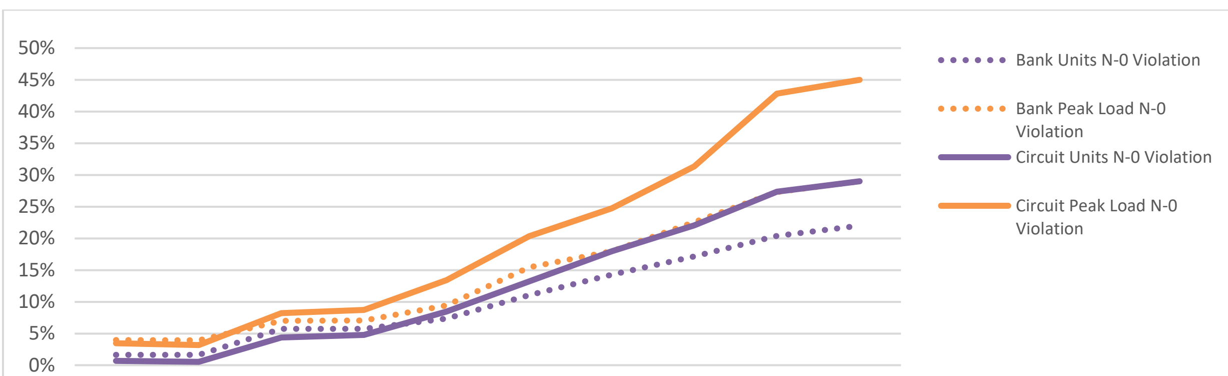


Figure 3. Summer Capacity Needs, Substation and circuits expected to incur in N-0 violations, as a percent of total service area, NYSEG

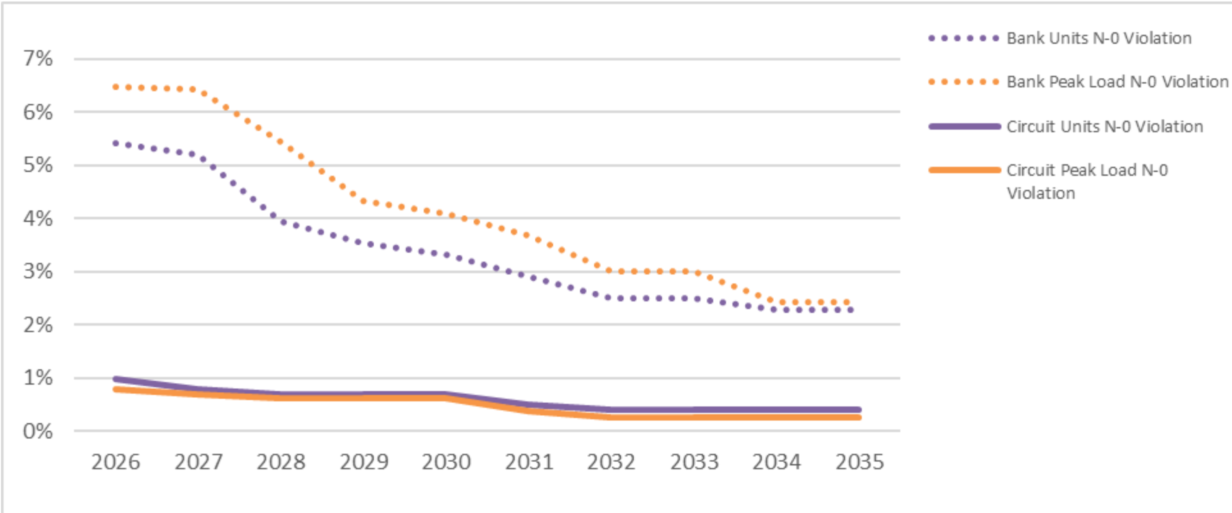
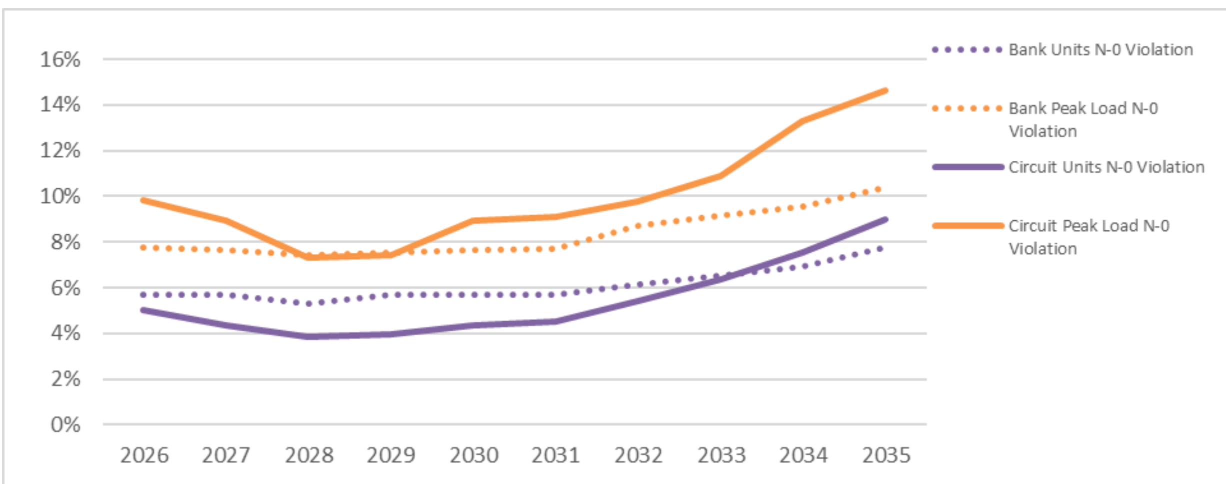


Figure 4 Summer Capacity Needs, Substation and circuits expected to incur in N-0 violations, as a percent of total service area, RG&E



5 APPROACH TO ESTIMATE UPSTREAM AND PRIMARY DELIVERY MARGINAL COSTS

A. Overall Approach Framework

The MCOS studies evaluate both the near-term and longer-term (10 year) incremental cost impact of peak load additions on the grid. The analysis requires gathering the required load and cost data inputs, examining the transmission, distribution and feeder investments that qualify for inclusion in the study, checking alignment with underlying growth forecast assumptions, and other detailed analysis including the extent to which the reliability projects take place as a result of the specific growth in the substation area or adjacent areas, as well as the capacity added.

The Companies' MCOS studies are in alignment with the Commission requirements. All relevant year by year capacity-related investments are first identified at the substation and feeder level and then divided by the specific project capacity added at that location. These costs are then aggregated and averaged by division level. Ultimately, system-wide marginal costs are estimated, along with levelized marginal costs over the 10-year period.

The basic steps in calculating the MCOS estimates can be summarized as follows:

1) Identification of investments in the capital plan, the pattern of annual expenditures at each location and areas affected, as well as the expected capacity gained from each substation or feeder project.
2) Identification of year-by-year marginal investments per kW of added carrying capability.
3) Evaluate peak load growth by 2035 that may drive additional units to be expanded to include potential projects not in the current Company's capital plan.
4) Estimation of year-by-year capacity-weighted marginal investments separately for each planning division within the service territory, by each of the four cost functions.
5) Annualization step, applying O&M expenses and loading factors for other administrative and general expenses.
6) Computing system-wide marginal cost, across the various divisions, averaging cost across all divisions, for distribution substations and feeders separately.
7) Identifying the share of the system that is not expected to experience capacity expansion and adjust the system-wide marginal costs per kW of load carrying capability after assigning zero weights to those substation and feeders.

A summary of these computational steps is provided below.

B. Selection of Relevant Investment from Companies' Capital Plan

For both Companies, a sizeable amount of reliability and growth-related investments is needed over the upcoming planning period to reliably meet growth in both NYSEG and RG&E service territories. These include investments related to meeting reliability standards and are designed by utility system planning engineers to handle granular forecasts of increased demand at the substation and feeder level. The Commission August Order stated the studies need to include multi-value investments, as long as they have a growth component. The MCOS study includes the planned investments needed to meet incremental peak load growth from either existing and/or new customers, and the associated capacity gained by the project.

Companies decide on the expansion of transmission, distribution substations and feeders based on the capacity needed on those facilities to reliably meet the forecasted substation area and feeder load over the planning period. CRA worked with the Companies to develop a detailed understanding of each specific transmission and distribution investment in the capital plan, with the goal to identify capacity solutions that would allow to produce reasonable marginal costs reflective of the next ten-year period.

The forecasted peak load growth is a combination of organic growth, anticipated electrification and/or economic activity.[5] These projects fall in the category of Distribution Load Relief, Reliability, Prospective Planning, and "Comprehensive Area Studies". Capacity-expansion Investments may address capacity deficiencies expected during base loading conditions (N-0), and/or design standard violations related to loss of one transformer or feeder contingencies (N-1).[6] In some cases, the transformer and feeder is expected to be able to serve forecasted demand under baseload conditions (N-0), but capacity expansion may still be needed if the area lacks adequate N-1 redundancy and cannot be fully backed-up through neighboring circuit field tie switching.[7] The Commission considers both types of investments as suitable for inclusion in a MCOS study to the extent that they are both driven by increased peak loads to some extent.

In general, if a significant change in forecasted peak load on the particular location is not expected to affect a specific planned investment, the project is considered to have little bearing on the marginal cost per kW of load carrying capability, and could distort the true cost of meeting incremental peak load or the benefit to the system of peak load shaving if included in the study. Investments that expand capacity largely as a result of replacing equipment that has reached the end of their useful life are an example where investment is needed regardless of peak loading, were not included in the study. The Companies' MCOS studies also exclude investments exclusively related to asset condition and modernization since the Company would have undertaken such investments regardless of the level of peak loading at the substation or feeder.

In consultation with the Companies, we reviewed service areas within the transmission and distribution system and the locations at the upstream (115kV, 34 kV) and the 12 kV system levels that are expected to face thermal and low voltage limits due to forecasted growth. Each Company selects the most cost-effective capacity solutions to address those constraints and ensure electrification and economic development can be met reliably. The type of solutions may involve a transformer replacement with larger capacity, increased circuit ties, and/or conductor voltage

---

[5] These projects fall in the category of Distribution Load Relief, Reliability, "Prospective Planning" and "Comprehensive Area Studies".

[6] For example, in the case of substations with more than one transformer, Company's standards require that the station peak load does not exceed the short-term emergency (STE) rating of the smaller transformer in the substation.

[7] Any N-1 investments suitable for the study are consistent with the Companies' reliability planning standards and not the result of a step change in the amount of redundancy needed per forecasted peak load growth.

conversion. In some areas, the Companies employ lower cost near-term solutions such as substation or feeder load transfers, to provide temporary capacity headroom prior to a longer-term solution.

The MCOS studies identify the year when a station and/or feeder-related project is scheduled to take place in each location, along with in-service date and capacity added. All projects must have in-service dates no later than by 2035. The approach recognizes that a given investment is typically phased in to reflect the Company's construction schedule.

The current Companies' capital plans were prepared for the 2025 electricity rate cases and includes dollars of investment through 2031. To address the longer timeframe required as per the Commission's Order, CRA reviewed additional plans that the Companies have developed under Comprehensive Area Studies (CAS) which included a collective set of transmission and distribution capacity solutions for the area expected to come into service from 2302 through 2035. These investments specifically relate to expected overload and electrification-related load during the longer timeframe.

Including the longer-term CAS projects, a total of 55 planned upstream projects and 57 distribution projects across substation transformer and feeders were included in NYSEG's MCOS study, and a total of 31 upstream projects and 61 distribution projects were included in RG&E's capital plan.

In addition to reviewing the projects identified by the Companies in their capital plans, CRA conducted an independent analysis to identify the share of substations and/or feeders potentially requiring growth-related capacity through year 2035, based on comparing 2035 forecasted load with 95 percent of each substation and feeder's CNR. This analysis was conducted to review potential additional investment needs or the last three years of the 10-year period (2033-2035). The focus of this exercise was on estimating substations and/or feeders potentially requiring capacity expansion for N-0 reasons and not additional investments for needed to mitigate N-1 violations, beyond those already identified in the transmission reinforcement programs of the Companies. This approach was intentionally conservative to reflect the fact that the Companies would not usually target all N-1 projects at any given period, given the potential excessive pressure on rates.[8] After accounting for these additional needs, a total of n average cost per substation and feeder was adopted long with consultation with Company planners on N-1 investments was used in the MCOS to project marginal unit costs through the study period.

8 This analysis considered the highest of winter and summer peak loads through the ten-year period. Peak load forecast relied on the annual growth rates forecasted by the Companies for the upcoming 10 years. CRA applied the forecasted growth to the current station and feeder peak loads, under the assumption that the projections of summer and winter annual system-wide growth rates are representative of the annual peak load percent change by all individual substations and feeders.

A. Identification of Incremental Capacity Expansion over 10-year period

Next, the study identified the capacity added by each project in each location. In areas where addition of a transformer is driven by N-1 needs, the calculation uses the total project added capacity to determine the marginal unit cost, and not only the capacity used under N-0 conditions. Typically, when peak loading on the substation or feeder begins to exceed 90% capacity, a mitigation strategy is employed to avoid voltage instability. The selected annual substation and feeder investments over the 2026-2035 period were divided by kW of added peak load carrying capability by multiplying added capacity by .9 to reflect the Companies' criteria.

All initial estimates of marginal investment were calculated on a substation/feeder basis for each year of the study period, separately for upstream (transmission) and distribution, within each division. These marginal costs are potentially avoided from peak load reductions anywhere in the system, as these facilities are planned for the collective demand of all customers downstream of the facilities.

The MCOS studies also capture the earlier years of construction of an asset. A customer adding 1 kW of Incremental peak load downstream of the particular facility in the year when the asset first begin construction is considered to contribute to the upcoming identified investment need and therefore the corresponding marginal investment per kVA of added carrying capability is calculated for each year of construction, using total project added carrying capability that is discounted to the respective year of construction.

B. Annualizing investment

The marginal investments per kW of load-carrying capability were annualized and converted to marginal costs by applying the appropriate economic carrying charges ("ECC"). The annualized ECC formula includes the salvage value of the plant. The ECC, when applied to a capital investment, produces the first-year annual revenue requirement of a series of annual capital charges that remain constant in real terms over the life of the asset.[9] The 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. The final step of the computation of annualized costs requires estimating marginal operation and maintenance ("O&M") expenses per kW and applying loading factors to account for general plant growth and administrative and general ("A&G") expenses, including an allowance for working capital. Distribution O&M expenses are a component of marginal cost, since they grow with the amount of plant in service.

[9] Revenue requirement includes the depreciation expense, minus net salvage cost, income taxes, and property insurance.

C. Calculating a system-wide weighted average cost

As a last step, CRA computed a system-weighted marginal unit cost that accounts for the share of the system not expected to require investments in transformer or feeder upgrade to meet future peak load growth. This last step is helpful to inform a geographically uniform rate, which would price a 1kW of peak load reduction or power injection anywhere in the service territory.

Estimating this average marginal cost ensure that any payments calculated to compensate for power injections into the grid are overall aligned with total capacity-related savings to the Company through the 10-year period. However, for informational purposes, the MCOS studies also calculate unweighted marginal unit costs, which are equivalent to assuming that injections to the grid anywhere in the system have a distribution value or that the entire Companies' systems will be in need of expansion.

6 RESULTS OF THE ANALYSIS

The MCOS studies computed substation and feeder marginal unit cost on $ per kW-yr, averaged by division for annualization purposes and system-wide. Annual marginal cost values for each component of the grid are stated in nominal dollars for each year, as well as levelized as a constant value for years 2026 to 2035. In accordance with the August Order, the marginal costs are shown at the local upstream (local transmission)[10], distribution substation, and distribution feeder level representing estimates of marginal costs per kW of incremental peak load served for each facility type, after evaluating both growth and multi-value projects within the ten-year planning horizon.

The marginal upstream, distribution and feeder cost per kW is shown in two ways. The first approach assumes that once the asset is in service, the marginal cost (or benefit) from 1 kW of peak load growth (or peak load reduction) on the asset going forward is zero. This marginal unit cost is consistent with the forward-looking marginal unit cost for new load coming into the system the year after investment has been completed. This effectively means that the marginal cost drops to zero once the facility gets into service.

The second set of results shows annualized marginal costs on a cumulative basis through the 10-year period, to illustrate the total incremental value that a resource contributing 1 kW of incremental peak demand reduction in each year would achieve through the 10-year period. These results are shown in the Appendix 1 and 2. Appendices 3 and 4 also include the detail on the substations and feeders and investment per kW added included for NYSEG and RG&E respectively.

---

10 The marginal cost estimates of high voltage feeder and high voltage (115 kV/34kV) substations were computed separately but then combined into the Upstream category for purposes of presentation of results.

D. NYSEG Results

Tables 1 and 2 reflect the system levelized marginal cost, averaged across all capacity solutions within each division.[11] All marginal cost estimates reflect fully loaded annualized marginal costs adjusted for loading factors and O&M. Each division's marginal cost is then weighted by its share of total peak load to compute system wide marginal costs. At this stage, the marginal costs have not been weighted for areas with excess capacity, however the individual division marginal costs reflect peak-load weighted marginal station costs using division's peak load relative to total non-coincident peak load at the specific segment in the system.

Table 1. NYSEG 10-year Levelized averaged system-wide Marginal Costs in Capacity-expanding Areas by Division

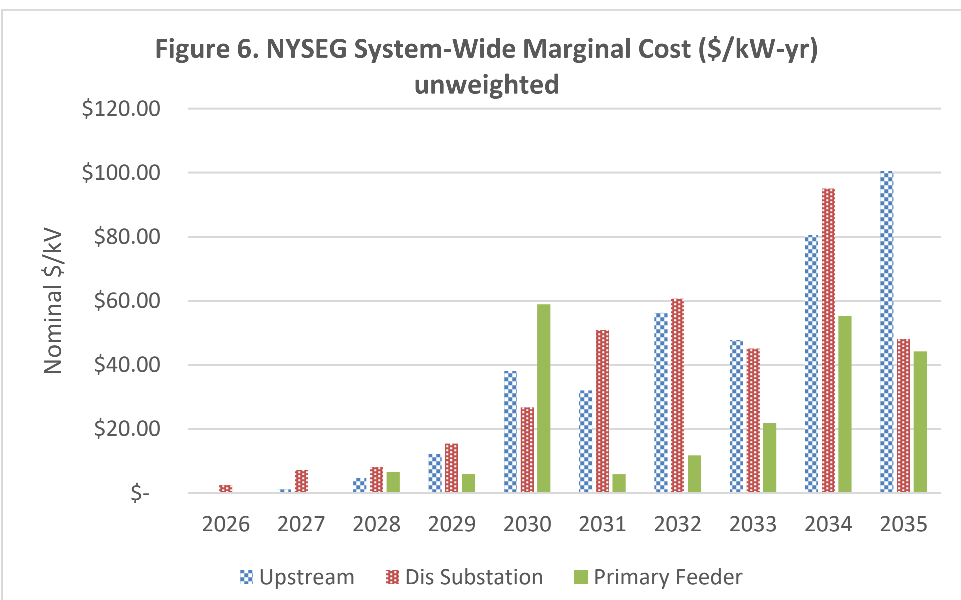
	Upstream $/kW	Dist Substation $/kW	Primary Feeder $/kW	Total MC at Primary level $/kW-yr	Secondary level $/kW-yr
Auburn	$16.57	$64.62	$27.86	**$112.37**	**$115.25**
Binghamton	$25.10	$56.18	$20.88	**$105.51**	**$108.22**
Brewster	$24.64	$12.04	$9.95	**$48.41**	**$49.66**
Elmira	$35.57	$0.00	$4.43	**$41.87**	**$42.94**
Geneva	$20.05	$26.22	$21.76	**$70.27**	**$72.07**
Hornell	$62.56	$37.44	$7.34	**$111.70**	**$114.57**
Ithaca	$56.55	$25.25	$9.98	**$95.55**	**$98.00**
Lancaster	$31.15	$23.26	$21.64	**$78.75**	**$80.77**
Liberty	$36.94	$29.78	$8.38	**$77.99**	**$79.99**
Lockport	$0.00	$0.00	$11.01	**$11.25**	**$11.54**
Mechanicville	$33.09	$8.68	$3.72	**$47.47**	**$48.69**
Oneonta	$9.95	$9.09	$7.22	**$27.18**	**$27.88**
Plattsburgh	$43.45	$26.42	$6.00	**$78.93**	**$80.95**
System-wide	**$29.74**	**$23.77**	**$12.87**	**$68.84**	**$70.61**

[11] The division with relatively larger forecasted peak load has a higher probability of representing a larger share of peak load and capacity additions relative to other areas system-wide. These projections were based on NYISO's 2025 "Gold Book" peak load projections for each respective Company's load zone, supplemented with the Company's own expectation for areas within the service territory likely to experience higher electrification, such as Ithaca area in the case of NYSEG.

Table 2. NYSEG Year-by-Year System-Wide Marginal Unit Cost in capacity-expanding areas (Nominal $)

Year	Upstream $/kW	Dis Substation $/kW	Primary Feeder $/kW	Total MC at Primary $/kW-yr	Total MC at Secondary $/kW-yr
2026	$ -	$ 2.39	$ -	**2.45**	**2.52**
2027	$ 1.09	$ 7.04	$ -	**8.38**	**8.60**
2028	$ 4.48	$ 7.86	$ 6.29	**19.22**	**19.72**
2029	$ 11.66	$ 14.83	$ 5.76	**33.39**	**34.24**
2030	$ 36.68	$ 25.77	$ 56.68	**122.95**	**126.10**
2031	$ 30.87	$ 48.70	$ 5.73	**88.39**	**90.65**
2032	$ 54.21	$ 57.95	$ 11.40	**128.20**	**131.49**
2033	$ 45.99	$ 39.00	$ 21.14	**110.02**	**112.84**
2034	$ 77.75	$ 30.68	$ 16.86	**130.42**	**133.76**
2035	$ 89.94	$ 28.51	$ 15.85	**139.95**	**143.54**
Levelized	**$29.74**	**$23.77**	**$12.87**	**$68.84**	**$70.61**

Figure 6 reflects the year-by-year system-wide marginal unit cost by division for each Company, representative of areas within the division that need to expand capacity to reliably meet growth. . Figure 7 shows each division's relative share of peak load in NYSEG service territory.



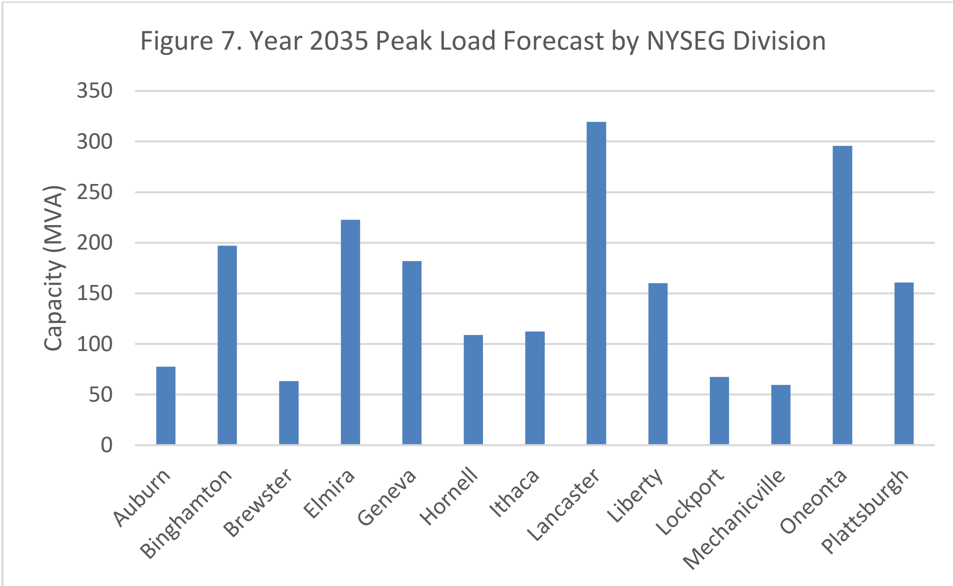


Table 3 reflects the year-by-year system *weighted* marginal cost, i.e., which factors areas that are expected to have ample capacity to meet forecasted peak demands (approximately 70 percent of the system) over the next 10-year timeframe.

Table 3. NYSEG Year-by-Year and 10-year Levelized averaged System-wide Marginal Costs after adjustment for excess capacity.

	Upstream $/kW	Dis Substation $/kW	Primary Feeder $/kW	Total MC at Primary $/kW-yr	Total MC at Secondary $/kW-yr
2026	$ -	$ 1.23	$ -	**1.27**	**1.30**
2027	$ 0.49	$ 3.75	$ -	**4.37**	**4.48**
2028	$ 1.73	$ 4.68	$ 2.09	**8.77**	**8.99**
2029	$ 8.29	$ 3.85	$ 0.63	**13.31**	**13.65**
2030	$ 17.61	$ 8.80	$ 8.49	**36.21**	**37.14**
2031	$ 16.45	$ 12.00	$ 1.56	**31.21**	**32.01**
2032	$ 28.71	$ 19.40	$ 4.27	**54.47**	**55.86**
2033	$ 21.41	$ 14.72	$ 10.53	**48.38**	**49.62**
2034	$ 26.65	$ 12.55	$ 7.00	**48.05**	**49.28**
2035	$ 25.52	$ 9.03	$ 5.02	**41.21**	**42.27**
Levelized Charge	**$12.75**	**$8.19**	**$3.48**	**$25.37**	**$26.02**

E. RG&E Results

Table 4 reflects the levelized marginal cost for RG&E by division, by component and total, adjusted by losses for primary and secondary voltage. Table 5 shows the annual marginal cost system-wide.

Table 4. RGE's 10-year levelized averaged system-wide marginal cost ($/kW-yr in capacity-expanding areas

Division	Upstream	Dis Substation	Primary Feeder	Total MC at Primary	Total MC at Secondary
Canandaigua	$19.69	$12.67	$5.94	$ 39.91	$ 41.83
Central	$54.25	$32.65	$32.21	$ 123.83	$ 129.81
Fillmore	$5.03	$0.00	$0.00	$ 5.30	$ 5.56
Sodus	$0.00	$9.58	$0.00	$ 9.89	$ 10.37
System-Average	**$48.88**	**$30.02**	**$28.70**	**$ 111.86**	**$ 117.27**

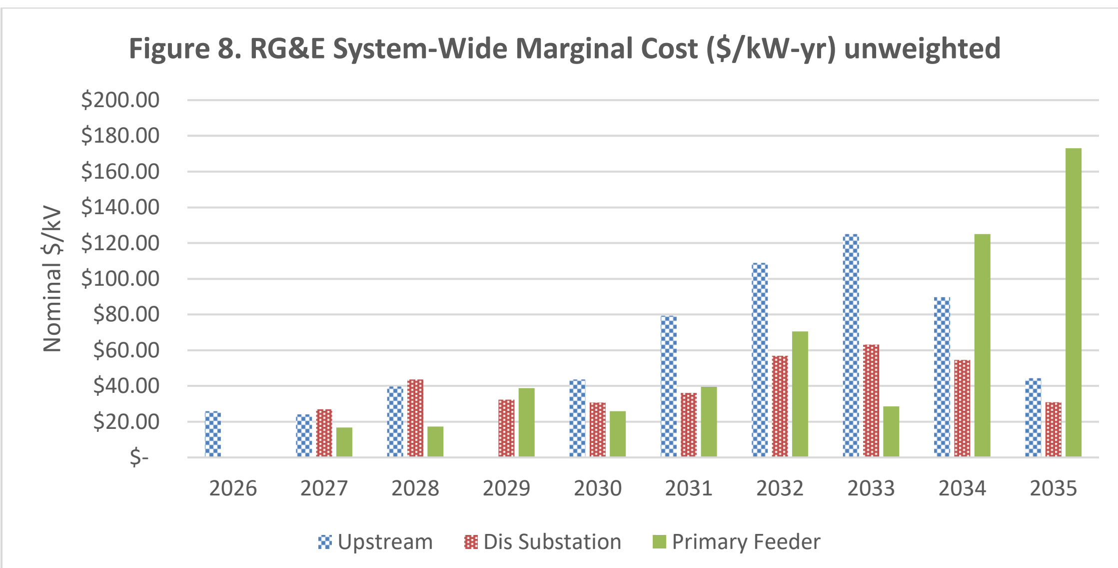
Table 5. RGE Year-by-Year System-Wide Marginal Unit Cost, in capacity-expanding areas (Nominal $)

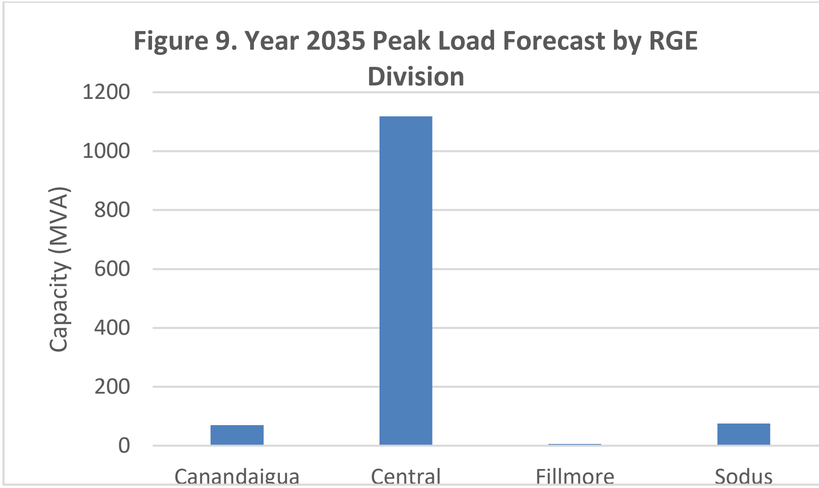
Year	Upstream $/kW	Dis Substation $/kW	Primary Feeder $/kW	Total MC at Primary $/kW-yr	Total MC at Secondary $/kW-yr
2026	$ 24.44	$ -	$ -	$ 25.77	$ 27.01
2027	$ 22.81	$ 23.46	$ 14.95	$ 63.55	$ 66.61
2028	$ 37.56	$ 39.01	$ 15.96	$ 96.18	$ 100.82
2029	$ -	$ 30.13	$ 36.76	$ 68.69	$ 72.01
2030	$ 41.30	$ 28.09	$ 22.61	$ 95.65	$ 100.27
2031	$ 69.63	$ 30.12	$ 33.54	$ 138.80	$ 145.50
2032	$ 97.10	$ 47.63	$ 58.15	$ 211.01	$ 221.19
2033	$ 113.70	$ 54.33	$ 26.31	$ 202.86	$ 212.65
2034	$ 84.54	$ 42.99	$ 25.40	$ 159.48	$ 167.18
2035	$ 41.92	$ 21.08	$ 85.61	$ 153.52	$ 160.93
Levelized	**$48.88**	**$30.02**	**$28.70**	**$111.86**	**$117.27**

Table 6 reflects system-wide marginal costs weighted by zero capacity-constrained areas i.e., effectively factoring areas that will have sufficient capacity to meet forecasted peak demands (approximately 65 percent) and therefore do not need upgrades or capacity-expansion projects in the 10-year timeframe.

Table 6. RG&E Year-by-Year System-Wide Marginal Unit Cost ($/kW-yr), weighted by excess capacity (Nominal $)

	Upstream $/kW	Dis Substation $/kW	Primary Feeder $/kW	Total MC at Primary $/kW-yr	Total MC at Secondary $/kW-yr
2026	$ 7.66	$ -	$ -	$ 8.080	$ 8.470
2027	$ 7.15	$ 7.54	$ 4.81	$ 20.24	$ 21.22
2028	$ 11.78	$ 12.54	$ 5.13	$ 30.61	$ 32.09
2029	$ -	$ 10.22	$ 11.82	$ 22.64	$ 23.74
2030	$ 12.95	$ 10.03	$ 7.27	$ 31.44	$ 32.96
2031	$ 21.83	$ 10.90	$ 10.78	$ 45.30	$ 47.48
2032	$ 34.25	$ 16.07	$ 18.70	$ 71.82	$ 75.29
2033	$ 42.11	$ 17.79	$ 10.54	$ 73.54	$ 77.09
2034	$ 26.51	$ 13.82	$ 8.17	$ 50.57	$ 53.01
2035	$ 13.15	$ 6.78	$ 27.53	$ 49.01	$ 51.38
Levelized Charge	**$16.20**	**$10.02**	**$9.40**	**$37.04**	**$38.82**





7 TIME-DIFFERENTIATION OF SYSTEM-WIDE MARGINAL UPSTREAM AND PRIMARY DISTRIBUTION INVESTMENT

For use in any pricing application, the annualized upstream distribution substation & feeder marginal cost needs to be allocated to all hours of the year that are more likely to drive investment needs. This analysis can be done by day-type and month, based on each hour's relative probability of being the annual peak, i.e. The MCOS uses a probability of peak (PoP) analysis using the distribution system hourly loads during the most three recent years (2022 - 2024), and a forecast for years 2025 and 2026 by further simulating hourly impacts on the system load profile from the expected near-term added electrification and behind the meter solar generation by typical day. The PoP produces allocation factors for each hour, by day-type (weekdays, weekends & holidays) and month. These factors are useful in evaluating the time differentiation of near-term marginal costs. However, updates to the analysis will be required every few years to estimate changes in appropriate time-differentiation.

The probability of peak analysis revealed that currently, the months of June, July and August combined account for approximately 91% and 99% of the annual cumulative probability of peak, for NYSEG and RG&E respectively. This assessment incorporates hourly distributions and temperature impact on grid carrying capability. For NYSEG, the remaining non-zero probabilities fall mainly in the months of September, and in December through February. For RG&E, outside of the June-August season, only the months of May and September have a moderate probability of peak, and the winter months' probability of peak is zero.

NYSEG summer peak loads are currently close to winter peak loads; and the summer peak loads still drive the near-term capacity expansion in the service territory. Additional BTM generation will reduce the number of hours in the summer that are likely to trigger capacity needs, given a reduction in mid-day loads. The evening distribution peak loads will increasingly be more likely to trigger grid capacity expansion, relative to mid-day hours in both summer and winter.

Figure 10. Expected Near-term Load Profile for a typical summer weekday, NYSEG

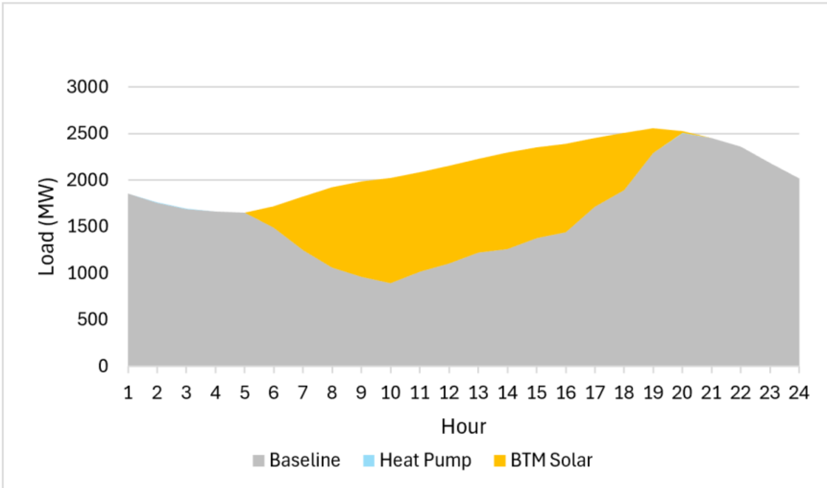
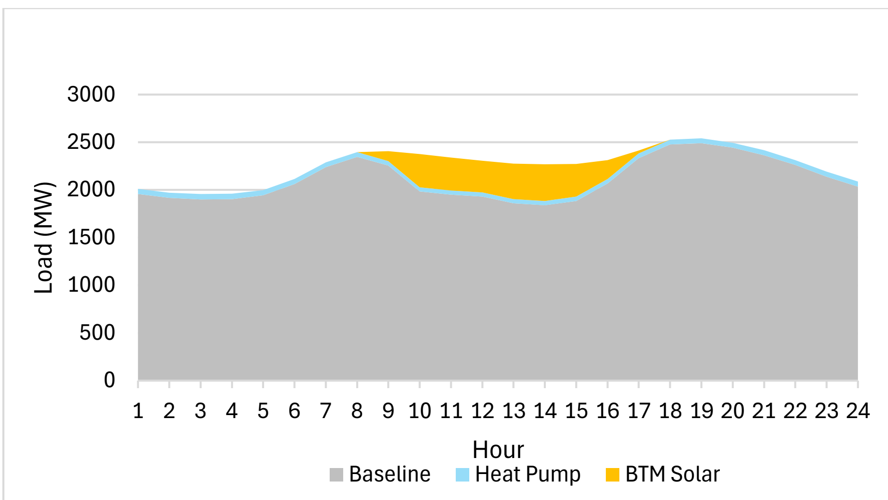
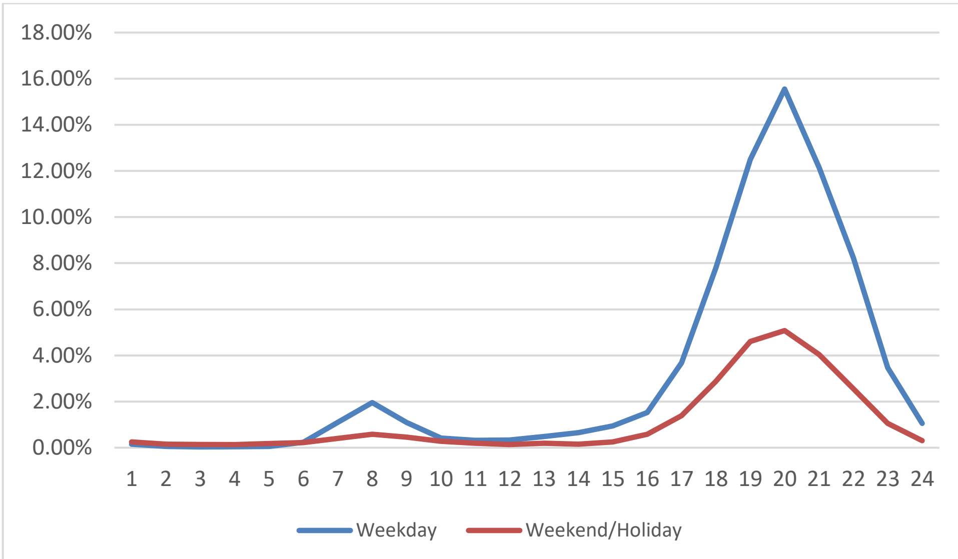


Figure 11. Expected Load Profile for a typical winter weekday, NYSEG



The expected year-round hourly probability of peak by day-type for NYSEG is shown in Figure 12 as an example. Through 2028, 25 percent of the NYSEG's cumulative summer probability of peak is expected to shift from the three core summer months of June through August to the three coldest winter months of Dec through February beginning by 2028. This cost-shifting effect is driven mainly by increased heat pump load use in the winter months, and transportation electrification in upcoming years, as well as increased behind the meter solar adoption. The peak hours concentrate between 5 pm and 9 pm throughout the year. The morning winter hours on weekdays will have a moderate contribution to investment needs, but to a much lower extent.

Figure 7. Hourly Year-Round Distribution Probability of Peak 2026-2028, NYSEG



8 LOCAL FACILITIES COSTS

Local distribution facilities in the context of MCOS studies refer to the secondary voltage lines, line transformers, and local primary taps. The Companies' engineers decide on the type of the required facilities using design standards that take into consideration the number of customers who are expected to use those facilities and their maximum demands over the service life of those facilities. The cost per customer may change depending on whether the system is radial or networked, i.e., whether there is potential for sharing the transformer extensively, and whether they are single or polyphase service. These facilities are less extensively shared compared to the upstream distribution substations and primary feeders.

To estimate the local facilities costs, the MCOS analysis included the review of an extensive sample of work orders associated with customer connection jobs for single-phase and three-phase customers in the most recent four years (2021-2024), for the Companies' residential, commercial and industrial customers. To estimate the typical installed cost of distribution facilities, CRA computed the average per kW cost of distribution facilities, net of customer contributions as per the prevailing line extension policy. Separate costs of facilities were estimated for underground vs. overhead, single-phase or three-phase, and ultimately a weighted average cost was calculated for each customer class, based on the customer mix within the class. Tables 7 and 8 summarize the annual marginal local distribution facilities costs, in today's dollars. Using the typical transformer size and the typical length of conductor that the Company installs and stated as a cost per kW of transformer capacity serving the customers connected to it.

Table 7. NYSEG Annual Marginal Local Distribution Facilities Costs

Customer Class		Annualized Dist. Facilities Cost per kW of Reserved Capacity
		(2025 $/kW/yr)
Residential		
SC01	Residential	$110.36
SC01 Seasonal	Residential - Seasonal	$110.36
SC08	Residential Day-Night	$110.36
SC08 Seasonal	Residential Day-Night - Seasonal	$110.36
SC12	Residential - TOU	$110.36
Non-Residential		
SC02	General Service with Demand Meter	$54.30
SC03P	Primary Service - 25KW or more	$47.33
SC03S	Subtransmission - 25KW or more	$0.00
SC06	Non-Residential Service	$137.37
SC71	Large General Service - Secondary	$108.75
SC72	Large General Service - Primary	$28.69
SC09	General Service Day-Night	$137.37

Table 8. RG&E's Annual Marginal Local Distribution Facilities Costs

Customer Class		Annualized Distribution Facilities Cost (after CIAC) per kW of Reserved Capacity
		(2025 $/kW/yr)
Residential		
SC01	Residential	$114.65
SC041	Residential TOU - Sch 1	$114.65
SC042	Residential TOU - Sch 2	$114.65
SC04 PEV	Residential - Plug-In EV	$114.65
General Service		
SC02	General Service - Small Use	$114.89
SC03	Medium GS (> 100 KW)	$42.07
SC03 HiVolt	Medium GS (>100 KW) - High Voltage	$35.65
SC07	General Service >12 KW	$75.25
SC08 - P	LGS - TOU Primary	$35.65
SC08 - S	LGS - TOU Secondary	$43.51
SC09	GS - TOU	$71.34
SC09 HiVolt	GS - TOU High Voltage Option	$35.65

APPENDIX 1

CUMMULATIVE MARGINAL COST OVER 10-YEAR PERIOD

Table A.1. NYSEG's 10-year levelized averaged system-wide marginal cost ($/kW-yr in capacity-expanding areas (cumulative MC)

	Upstream $/kW	Dist Substation $/kW	Primary Feeder $/kW	Total MC at Primary level $/kW-yr	Secondary level $/kW-yr
Auburn	$57.18	$325.00	$93.10	**$489.65**	**$502.20**
Binghamton	$45.96	$159.35	$44.92	**$258.14**	**$264.76**
Brewster	$88.41	$41.44	$14.30	**$150.07**	**$153.92**
Elmira	$101.97	$0.00	$30.18	**$137.88**	**$141.42**
Geneva	$49.85	$119.38	$114.53	**$292.23**	**$299.72**
Hornell	$255.36	$164.14	$25.54	**$463.09**	**$474.96**
Ithaca	$211.05	$97.39	$11.44	**$333.47**	**$342.02**
Lancaster	$90.14	$116.49	$115.64	**$332.69**	**$341.21**
Liberty	$126.35	$140.87	$33.93	**$312.29**	**$320.30**
Lockport	$0.00	$0.00	$58.85	**$60.15**	**$61.69**
Mechanicville	$47.41	$12.49	$19.89	**$82.96**	**$85.09**
Oneonta	$14.30	$13.08	$38.61	**$67.93**	**$69.67**
Plattsburgh	$182.85	$118.99	$18.17	**$332.97**	**$341.51**
System-wide	**$92.67**	**$95.36**	**$54.51**	**$251.12**	**$257.56**

Table A.2. NYSEG's 10-year annualized system-wide marginal cost ($/kW-yr) in capacity expanding areas (cumulative MC)

Year	Upstream $/kW	Dis Substation $/kW	Primary Feeder $/kW	Total MC at Primary $/kW-yr	Total MC at Secondary $/kW-yr
2026	$ -	$ 2.39	$ -	**2.45**	**2.52**
2027	$ 1.09	$ 9.47	$ -	**10.89**	**11.17**
2028	$ 5.59	$ 17.52	$ 6.29	**30.33**	**31.11**
2029	$ 17.36	$ 32.71	$ 12.17	**64.32**	**65.97**
2030	$ 54.39	$ 59.13	$ 69.10	**188.56**	**193.39**
2031	$ 86.34	$ 109.01	$ 76.21	**280.72**	**287.92**
2032	$ 142.29	$ 169.14	$ 89.14	**414.54**	**425.16**
2033	$ 191.12	$ 211.52	$ 112.07	**532.85**	**546.51**
2034	$ 272.70	$ 246.43	$ 131.16	**673.93**	**691.20**
2035	$ 368.09	$ 279.87	$ 149.63	**827.36**	**848.57**
Levelized	**$92.67**	**$95.36**	**$54.51**	**$251.12**	**$257.56**

Table A.3. NYSEG's 10-year annualized system-wide marginal cost ($/kW-yr) adjusting for excess capacity (cumulative MC)

	Upstream $/kW	Dis Substation $/kW	Primary Feeder $/kW	Total MC at Primary $/kW-yr	Total MC at Secondary $/kW-yr
2026	$ -	$ 1.23	$ -	**1.27**	**1.30**
2027	$ 0.49	$ 5.01	$ -	**5.66**	**5.81**
2028	$ 2.22	$ 9.78	$ 2.09	**14.54**	**14.92**
2029	$ 10.55	$ 13.83	$ 2.77	**28.14**	**28.86**
2030	$ 28.37	$ 22.91	$ 11.31	**64.92**	**66.58**
2031	$ 45.39	$ 35.37	$ 13.09	**97.43**	**99.93**
2032	$ 75.01	$ 55.48	$ 17.62	**153.84**	**157.79**
2033	$ 97.91	$ 71.31	$ 28.51	**205.30**	**210.57**
2034	$ 126.52	$ 85.28	$ 36.08	**257.46**	**264.06**
2035	$ 154.58	$ 96.02	$ 41.82	**303.82**	**311.61**
Levelized Charge	**$44.43**	**$33.51**	**$12.69**	**$94.10**	**$96.51**

Table A.4. NYSEG's 10-year annualized system-wide marginal cost ($/kW-yr) by Division, unadjusted for excess capacity (cumulative MC)

on	Cost Function	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Auburn	Upstream	$ -	$ -	$ -	$ -	$ 14.99	$ 46.19	$ 93.93	$ 157.33	$ 197.44	$ 201.39
	Distribution	$ 34.89	$ 92.15	$ 208.03	$ 212.20	$ 292.01	$ 354.93	$ 464.19	$ 613.02	$ 702.39	$ 716.44
	Feeder	$ -	$ -	$ -	$ -	$ 19.24	$ 60.20	$ 146.18	$ 264.14	$ 333.92	$ 340.60
Binghamton	Upstream	$ -	$ -	$ -	$ -	$ -	$ -	$ 30.10	$ 70.99	$ 171.80	$ 332.38
	Distribution	$ -	$ -	$ -	$ -	$ -	$ -	$ 215.54	$ 503.15	$ 610.84	$ 705.90
	Feeder	$ -	$ -	$ -	$ -	$ -	$ -	$ 18.19	$ 101.84	$ 195.43	$ 272.00
Brewster	Upstream	$ -	$ -	$ -	$ -	$ 133.67	$ 136.34	$ 139.07	$ 141.85	$ 210.02	$ 297.07
	Distribution	$ -	$ -	$ -	$ -	$ 60.76	$ 61.98	$ 63.22	$ 64.48	$ 101.10	$ 146.30
	Feeder	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 58.86	$ 134.33
Elmira	Upstream	$ -	$ -	$ -	$ -	$ 128.26	$ 130.82	$ 133.44	$ 136.11	$ 271.90	$ 446.20
	Distribution	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Feeder	$ -	$ -	$ 38.14	$ 38.90	$ 39.68	$ 40.47	$ 41.28	$ 42.11	$ 42.95	$ 43.81
Geneva	Upstream	$ -	$ -	$ -	$ -	$ -	$ 35.17	$ 69.48	$ 102.99	$ 170.38	$ 256.64
	Distribution	$ -	$ -	$ -	$ -	$ 30.70	$ 242.18	$ 281.95	$ 287.58	$ 293.34	$ 299.20
	Feeder	$ -	$ -	$ -	$ 64.10	$ 146.33	$ 195.80	$ 224.08	$ 228.56	$ 233.13	$ 237.80
Hornell	Upstream	$ -	$ -	$ 35.72	$ 93.73	$ 192.88	$ 335.05	$ 456.59	$ 561.37	$ 637.93	$ 733.54
	Distribution	$ -	$ -	$ -	$ 31.79	$ 94.75	$ 212.29	$ 366.12	$ 414.71	$ 423.01	$ 431.47
	Feeder	$ -	$ -	$ -	$ -	$ -	$ -	$ 59.07	$ 85.52	$ 87.23	$ 88.98
Ithaca	Upstream	$ -	$ -	$ -	$ 49.56	$ 145.41	$ 247.07	$ 384.65	$ 472.91	$ 581.93	$ 676.42
	Distribution	$ 18.94	$ 48.02	$ 69.99	$ 71.39	$ 72.82	$ 74.28	$ 139.00	$ 141.78	$ 164.64	$ 299.90
	Feeder	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 19.79	$ 136.69
Lancaster	Upstream	$ -	$ -	$ -	$ -	$ -	$ 54.16	$ 148.21	$ 239.52	$ 305.98	$ 390.12
	Distribution	$ -	$ -	$ -	$ 58.13	$ 113.41	$ 191.17	$ 243.39	$ 248.25	$ 253.22	$ 258.28
	Feeder	$ -	$ -	$ -	$ -	$ 213.15	$ 217.42	$ 221.76	$ 226.20	$ 230.72	$ 235.34
Liberty	Upstream	$ -	$ -	$ -	$ -	$ 56.36	$ 57.49	$ 210.74	$ 358.56	$ 440.80	$ 449.61
	Distribution	$ -	$ 41.59	$ 71.91	$ 87.75	$ 124.81	$ 170.60	$ 215.21	$ 240.72	$ 329.58	$ 336.17
	Feeder	$ -	$ -	$ 26.61	$ 27.15	$ 27.69	$ 28.24	$ 28.81	$ 63.03	$ 96.53	$ 98.46
Lockport	Upstream	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Distribution	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Feeder	$ -	$ -	$ -	$ -	$ 108.48	$ 110.65	$ 112.87	$ 115.12	$ 117.43	$ 119.77
Mechanicville	Upstream	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 193.85	$ 446.96
	Distribution	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 51.57	$ 117.24
	Feeder	$ -	$ -	$ -	$ -	$ 36.67	$ 37.40	$ 38.15	$ 38.91	$ 39.69	$ 40.49
Oneonta	Upstream	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 58.86	$ 134.33
	Distribution	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 53.93	$ 122.77
	Feeder	$ -	$ -	$ -	$ -	$ 71.17	$ 72.59	$ 74.05	$ 75.53	$ 77.04	$ 78.58
Plattsburgh	Upstream	$ -	$ 13.69	$ 46.34	$ 120.90	$ 159.98	$ 227.42	$ 311.38	$ 342.45	$ 414.64	$ 505.79
	Distribution	$ -	$ -	$ -	$ 35.63	$ 81.13	$ 159.14	$ 257.33	$ 290.49	$ 296.30	$ 302.23
	Feeder	$ -	$ -	$ -	$ -	$ -	$ -	$ 13.01	$ 71.68	$ 73.11	$ 74.57
System-Wide (Division peak load-weighted)	Upstream	**$ -**	**$ 1.09**	**$ 5.59**	**$ 17.36**	**$ 54.39**	**$ 86.34**	**$ 142.29**	**$ 191.12**	**$ 272.70**	**$ 368.09**
	Distribution	**$ 2.39**	**$ 9.47**	**$ 17.52**	**$ 32.71**	**$ 59.13**	**$ 109.01**	**$ 169.14**	**$ 211.52**	**$ 246.43**	**$ 279.87**
	Feeder	**$ -**	**$ -**	**$ 6.29**	**$ 12.17**	**$ 69.10**	**$ 76.21**	**$ 89.14**	**$ 112.07**	**$ 131.16**	**$ 149.63**

Table A.5. RG&E's 10-year levelized averaged system-wide marginal cost ($/kW-yr in capacity-expanding areas (cumulative MC)

Division	Upstream	Dis Substation	Primary Feeder	Total MC at Primary	Total MC at Secondary
Canandaigua	$62.97	$60.08	$17.01	**$ 145.80**	**$ 152.84**
Central	$228.65	$148.36	$127.47	**$ 524.56**	**$ 549.89**
Fillmore	$14.40	$0.00	$0.00	**$ 15.18**	**$ 15.92**
Sodus	$0.00	$61.43	$0.00	**$ 63.39**	**$ 66.46**
System-Average	**$204.90**	**$137.62**	**$113.19**	**$ 473.83**	**$ 496.70**

Table A.6. RG&E's 10-year annualized system-wide marginal cost ($/kW-yr) in capacity expanding areas (cumulative MC)

Year	Upstream $/kW	Dis Substation $/kW	Primary Feeder $/kW	Total MC at Primary $/kW-yr	Total MC at Secondary $/kW-yr
2026	$ 24.44	$ -	$ -	$ 25.77	$ 27.01
2027	$ 47.73	$ 23.46	$ 14.95	$ 89.83	$ 94.16
2028	$ 86.25	$ 62.93	$ 31.21	$ 187.80	$ 196.87
2029	$ 87.97	$ 94.32	$ 68.60	$ 260.26	$ 272.82
2030	$ 131.03	$ 124.30	$ 92.58	$ 361.11	$ 378.55
2031	$ 203.28	$ 156.90	$ 127.97	$ 507.14	$ 531.62
2032	$ 304.44	$ 207.67	$ 188.68	$ 728.29	$ 763.45
2033	$ 424.23	$ 266.16	$ 218.76	$ 945.71	$ 991.38
2034	$ 517.26	$ 314.47	$ 248.54	$ 1,124.11	$ 1,178.38
2035	$ 569.53	$ 341.84	$ 339.12	$ 1,300.11	$ 1,362.88
Levelized	**$204.90**	**$137.62**	**$113.19**	**$473.83**	**$496.70**

Table A.7. RG&E's 10-year annualized system-wide marginal cost ($/kW-yr) adjusting for excess capacity (cumulative MC)

	Upstream $/kW	Dis Substation $/kW	Primary Feeder $/kW	Total MC at Primary $/kW-yr	Total MC at Secondary $/kW-yr
2026	$ 7.66	$ -	$ -	$ 8.08	$ 8.47
2027	$ 14.97	$ 7.54	$ 4.81	$ 28.48	$ 29.86
2028	$ 27.04	$ 20.24	$ 10.04	$ 59.67	$ 62.55
2029	$ 27.59	$ 30.87	$ 22.06	$ 83.50	$ 87.53
2030	$ 41.09	$ 41.52	$ 29.77	$ 116.61	$ 122.24
2031	$ 63.74	$ 53.24	$ 41.15	$ 164.24	$ 172.17
2032	$ 99.27	$ 70.38	$ 60.67	$ 239.35	$ 250.91
2033	$ 143.36	$ 89.58	$ 72.43	$ 317.68	$ 333.02
2034	$ 172.74	$ 105.20	$ 82.05	$ 374.60	$ 392.69
2035	$ 189.34	$ 114.08	$ 111.22	$ 431.11	$ 451.92
Levelized Charge	**$67.04**	**$46.00**	**$36.89**	**$155.89**	**$163.42**

Table A.8. RG&E's 10-year annualized system-wide marginal cost ($/kW-yr) by Division, unadjusted for excess capacity (cumulative MC)

Division	Cost Function	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Canandaigua	Upstream	$ -	$ -	$ -	$ -	$ -	$ -	$ 85.98	$ 233.14	$ 237.80	$ 242.56
	Distribution	$ -	$ -	$ -	$ 18.44	$ 53.13	$ 95.86	$ 123.83	$ 137.33	$ 140.08	$ 142.88
	Feeder	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 71.67	$ 73.11	$ 74.57
Central	Upstream	$ 27.75	$ 54.20	$ 97.93	$ 99.89	$ 148.78	$ 230.82	$ 340.33	$ 466.85	$ 572.18	$ 631.23
	Distribution	$ -	$ 25.46	$ 68.11	$ 101.70	$ 132.61	$ 166.10	$ 221.88	$ 287.32	$ 341.88	$ 372.66
	Feeder	$ -	$ 16.98	$ 35.44	$ 77.89	$ 105.12	$ 145.31	$ 214.25	$ 243.93	$ 277.66	$ 380.42
Fillmore	Upstream	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 60.67	$ 61.88	$ 63.12
	Distribution	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Feeder	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sodus	Upstream	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Distribution	$ -	$ 17.36	$ 49.47	$ 62.81	$ 77.07	$ 89.92	$ 91.72	$ 93.56	$ 95.43	$ 97.34
	Feeder	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
System-Wide	Upstream	$ 24.44	$ 47.73	$ 86.25	$ 87.97	$ 131.03	$ 203.28	$ 304.44	$ 424.23	$ 517.26	$ 569.53
(Division Peak	Distribution	$ -	$ 23.46	$ 62.93	$ 94.32	$ 124.30	$ 156.90	$ 207.67	$ 266.16	$ 314.47	$ 341.84
Load-weighted)	Feeder	$ -	$ 14.95	$ 31.21	$ 68.60	$ 92.58	$ 127.97	$ 188.68	$ 218.76	$ 248.54	$ 339.12