STATE OF NEW YORK
DEPARTMENT OF PUBLIC SERVICE

Case 15-E-0751 - In the Matter of the Value of Distributed Energy Resources.

Case 19-E-0283 - Proceeding on Motion of the Commission to Examine Utilities' Marginal Cost of Service Studies.

DEPARTMENT OF PUBLIC SERVICE STAFF PROPOSAL ON UPDATING DRV AND LSRV FOR VDER COMPENSATION

Dated: December 11, 2025

INTRODUCTION AND BACKGROUND

On April 18, 2019, the Public Service Commission (Commission) issued the Value Stack Compensation Order, which initiated a new proceeding in Case 19-E-0283 to examine Marginal Cost of Service (MCOS) studies that would be used in determining several components of the Value of Distributed Energy Resources (VDER) Value Stack (commonly referred to as "the MCOS proceeding").[1] The Commission explained that MCOS studies are critically important to dynamically evolving utility systems and to inform updates to the VDER Value Stack, but that significant variations existed in how the MCOS studies are conducted across the Joint Utilities, which include Central Hudson Gas & Electric Corporation (Central Hudson), Consolidated Edison Company of New York, Inc. (Con Edison), New York State Electric & Gas Corporation (NYSEG), Niagara Mohawk Power Corporation d/b/a National Grid (National Grid), Orange and Rockland Utilities, Inc. (O&R), and Rochester Gas and Electric Corporation (RG&E). Accordingly, the Commission determined that an inquiry into the MCOS study methodologies was required to ensure the most accurate estimates of the likely marginal distribution system cost reductions attributable to electricity injections from VDER-eligible distributed generators.[2] The MCOS proceeding was intended to help identify future electric delivery system costs that can be avoided when VDER-eligible distributed generators reduce net load on parts of the distribution system. Specifically, the Commission focused on the Demand Reduction Value (DRV) and Locational System Relief Value (LSRV) components of the VDER Value Stack.[3]

The Value Stack Compensation Order also stated that previously approved MCOS studies would continue to be used for calculating the LSRV and DRV components of the VDER Value Stack until the MCOS proceeding results in new MCOS studies approved by the Commission.

Significant processes were undertaken in the MCOS proceeding, including stakeholder forums and multiple rounds of information requests from the Solar Energy Industries Association

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[1] Case 15-E-0751, Order Regarding Value Stack Compensation (issued April 18, 2019) (Value Stack Compensation Order).

[2] Marginal costs are estimated as the expected change in cost resulting from a forecasted change in demand (or load).

[3] The Commission explained that LSRV compensation is available only in locations that the utility has identified as having needs that can be addressed by Distributed Energy Resources (DERs), and based on the higher, specific distribution costs offset by injections in that area. DRV compensation is based on the distribution costs offset by injections, averaged across the utility's service territory. Value Stack Compensation Order, p. 4.

(SEIA) jointly with other Clean Energy Parties (collectively, CEP or the Clean Energy Parties) and the City of New York (the City).[4]

On March 27, 2023, Staff submitted a Whitepaper Regarding Marginal Cost of Service Studies (Staff Whitepaper) in Case 19-E-0283.[5] Staff also held a technical conference on May 2, 2023, to provide an opportunity for interested entities to engage with Staff regarding the Staff Whitepaper proposals and to better inform their comments. The Joint Utilities, CEP, and the City (together "the Parties") submitted initial and reply comments in response to the proposals outlined in the Staff Whitepaper on July 20, 2023, and August 18, 2023, respectively.

On August 15, 2024, the Commission issued its Order Addressing Marginal Cost of Service Studies.[6] In the MCOS Order, the Commission established a methodology for estimating marginal costs to inform system wide applications such as DRV. The Commission then directed the Joint Utilities to file MCOS studies contemporaneously with their next round of Distribution System Implementation Plans (DSIPs) when due on June 30, 2025.[7] The Commission also directed Staff to initiate a collaborative process in Case 15-E-0751 to discuss issues related to forward looking costing and compensation, especially as it relates to DRV and LSRV values. A technical conference with presentations by the Parties was held on October 1, 2024. Staff filed a workplan for this collaborative process on October 25, 2024, with the goal of determining how best to use the updated marginal cost estimates to develop the LSRV and DRV.

On November 22, 2024, comments were filed on questions Staff had raised regarding presentations made by the Joint Utilities and CEP. In those comments, the Joint Utilities and CEP/SEIA provided additional details on their proposals. Given the complexity of the proposals, a revised workplan was filed on December 19, 2024, and a stakeholder meeting was held on January 30, 2025, to further discuss the Joint Utilities' and CEP's proposals. During that stakeholder meeting, Staff provided a hypothetical dataset the Parties could use to help illustrate

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[4] The responses to CEP's and the City's questions were filed in Case 19-E-0283 on June 7, 2019, July 31, 2019, September 30, 2019, and November 6, 2019.

[5] The Joint Utilities' responses to additional information requests from Staff with relevant information were attached as an appendix to the Staff Whitepaper.

[6] Case 15-E-0751 - In the Matter of the Value of Distributed Energy Resources; Case 19-E-0283 – Proceeding on Motion of the Commission to Examine Utilities' Marginal Cost of Service Studies, Order Addressing Marginal Cost of Service Studies (issued August 19, 2024) (MCOS Order).

[7] See, Case 16-M-0411, Distributed System Implementation Plans, Ruling on Extension Request (issued February 7, 2024).

Value Stack compensation proposals for LSRV and DRV. Staff requested that the parties use these data to provide more detail on the workings of their own proposals and concerns they might have with other Parties' proposals. Additional comments on the Parties' proposals were filed on February 26, 2025. CEP also presented a simplified proposal in their comments.

On June 30, 2025, the Joint Utilities filed marginal cost of service studies in compliance with the MCOS Order. Supporting workpapers for the studies, including underlying details regarding included investment project costs were filed between July 1, 2025, and July 11, 2025. NYSEG and RG&E provided (still not filed and unlocked) corrected MCOS studies on July 15, 2025. On August 14, 2025, NYSEG and RG&E filed updated and unlocked versions of their Marginal Cost of Service studies. Staff's proposal presented below is informed by the results of those studies.

STAFF PROPOSAL

Staff proposes the following procedures for the calculation of DRV and LSRV on a biennial cadence contemporaneously with the filing of MCOS studies to be included with the utilities' DSIPs.[8] As indicated in the August 2024 MCOS Order, VDER compensation should be based on long run avoided costs. Basing LSRV and DRV on short-run costs would not be consistent with a VDER goal of substituting avoidable utility investment with DER investment and would not provide a market signal for the most cost-efficient solutions.[9] Long-run marginal cost-based pricing is grounded in two varied but accepted objectives of regulatory economics. First, the long-run equilibrium price for a competitive industry reflects prices set at long run marginal cost. Thus, compensation based on long run marginal cost provides a price signal for the efficient entry of DER providers. Second, economically efficient rate designs produce a level of demand that would come about if prices were set equal to long-run marginal costs.[10] In a natural monopoly setting, prices must not be set at the profit maximizing level where demand

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8 We recommend that the LSRV and DRV results be filed in both cases 15-E-0751 and 19-E-0283. In addition, although the Commission's ordering clause 1 of the August 19, 2024, MCOS Order requires that the MCOS studies be filed along with the DSIPs in Cases 14-M-0101 and 16-M-0411, we recommend that those MCOS studies also be filed in both cases 15-E-0751 and 19-E-0283.

9 MCOS Order, pp. 13, 16, 20.

10 See Appendix A for a more detailed discussion of the economics underlying the pricing decisions in this proposal.

intersects with marginal revenue. Nor should such prices be set at the level of short run marginal costs which will not be fully compensatory. Rather, efficient rate design practices should be used to set prices which result in quantities consistent with the level of demand at which demand intersects long-run marginal costs.

A. DRV

The MCOS Order states that marginal cost calculations related to system-wide applications "should reflect long-run, non-zero marginal costs regardless of whether segments of a utility's distribution system have no avoidable costs due to near term expected changes in demand."[11] This finding re-affirmed the Commission's precedent for using a longer-run study for system-wide energy efficiency evaluation.[12]

The Value Stack Compensation Order requires $/kW-year DRVs to reflect the average system-wide marginal cost estimates de-averaged to reflect LSRV.[13] However, Staff proposes that the DRV be calculated as the system-wide average MCOS of all areas, not just the average of MCOS in non-LSRV areas.[14] As will be explained below, Staff proposes that DRV vs. LSRV eligibility be more than a function of the relative level of costs in LSRV and DRV areas. Thus, deaveraging the level of costs as the primary means of distinguishing compensation between DRV and LSRV areas is no longer appropriate. 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.

However, in setting the DRV in Staff's proposal, there is a critical departure from the system-wide MCOS calculation that has traditionally used to justify energy efficiency programs. The August 2024 MCOS order indicated that system wide MCOS results should not be calculated inclusive of zero marginal costs for serving areas that do not have planned capital

11 MCOS Order, p. 16.

12 March 26, 2010, Con Edison rate case Order, 09-E-0428 p. 22.

13 Value Stack Compensation Order, p. 19.

14 Specifically, Staff proposes that the DRV be calculated as the system-wide average MCOS of all non-zero cost areas. Staff does not propose to average the cost of non-zero, non-LSRV areas

projects.[15] Thus, Staff removed all areas with no planned projects when calculating a system wide average. Nevertheless, 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 non-zero costs in a substation serving area. Per the August 2024 order, the utilities presented project costs by each and every substation area. Those substation areas that were not affected by projects in any segment were removed before staff calculated a system wide average cost based on the sum of the segment costs in the remainder of the substation service areas.[16]

Staff's also recognizes that the calculation of system wide average MCOS using the pre-2018 "NERA method" for aggregating segment costs is not reflective of a completely hypothetically long run cost situation. However, we are faced with a somewhat hypothetical situation in that very few, if any, substation areas are affected by proposed relief projects across all network segments. Staff's method of aggregating the segment costs actually faced by each substation produces a more reasonable longer run cost estimate to use as a price signal.[17] On the one hand, including substation areas with zero segment costs is overly short run and would provide a signal that absolutely no DER entry is warranted in that substation area. On the other hand, aggregating all the segment costs together, regardless of whether a substation area faces the need for load relief across all network segments, unreasonably provides a price signal that full scale competitive entry is needed everywhere, now.

Appendix B contains a table showing how Staff's proposed DRV values compare with those currently in place. Staff made a number of modifications and corrections to the MCOS study results in order to place the study information on a consistent basis. A list of Staff's modifications is included in Appendix C, and in the companion Staff workpaper file, "Staff_DRV_LSRV_Proposal_Workpaper.xlsx" that will be filed contemporaneously with this

[15] Footnote 21 of the August 2024 MCOS order states "In referring to the NERA methodology, we understand this to be the pre-2018 NERA methodology, and not the 2018 method that the Brattle Group consultants modified for the Con Edison study filing in this proceeding to include estimates of zero marginal costs for serving areas that do not have planned capital projects."

[16] Specifically, Staff calculated a MW weighted system wide average cost of the completely non-zero substation area total of all segment costs.

[17] Consistent with page 16 of the August 2024 MCOS order, Staff's proposal produces "long-run, non-zero marginal costs regardless of whether segments of a utility's distribution system have no avoidable costs due to near term expected changes in demand."

proposal. Appendix B also estimates the DRV based on the Joint Utilities' and CEP's proposals if applied to the utilities' June 30, 2025, MCOS study filings. Finally, Appendix B provides an example which illustrates the estimation of systemwide average MCOS using Staff's proposed method of aggregating segment costs.

B. <u>LSRV</u>

The Value Stack Compensation Order indicated that both the DRV and the LSRV should reflect distribution costs, offset by injections:[18]

> DRV, based on the distribution costs offset by injections, averaged across the utility's service territory; and LSRV, available only in locations that the utility has identified as having needs that can be addressed by DERs, and based on the higher, specific distribution costs offset by injections in that area.

Not only is the LSRV intended to recognize that certain areas have much higher than average marginal costs, it is also meant to offer meaningful price signals to incentivize and compensate projects that create actual locational value.[19] And, although an LSRV that solely reflects higher than average marginal costs would be sufficient to signal the locational value, the Value Stack Compensation Order also realized that other distinguishing features associated with LSRV projects are necessary to ensure that LSRV can meet the demand needs in high cost areas. Operational requirements such as those related to the design of the LSRV call windows were used to ensure that LSRV projects could meet the demand needs in high-cost areas. The Value Stack Compensation Order did not lower the LSRV from its higher locational cost-based level to reflect concerns about the dispatchability and reliability of LSRV projects.[20]

Staff proposes a single level of LSRV for each utility which reflects the threshold level at which a utility's costs are significantly higher than costs on average on a system-wide basis.

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[18] Value Stack Compensation Order, p. 4.

[19] Value Stack Compensation Order, p. 17.

[20] As described in the next section, reliability and dispatchability concerns should be addressed via additional terms and conditions in the tariff language related to the dispatchability and reliability of LSRV projects.

Staff also contends that the LSRV should relate to about ten percent of a company's service areas.[21] Thus, Staff proposes that the LSRV be set to reflect 1.645 standard errors[22] above the system-wide average MCOS. Appendix D describes the statistical framework Staff relied upon in proposing LSRV threshold.

Staff's proposal that the LSRV be set to reflect 1.645 standard errors above the system-wide average MCOS invites the question - why are the high unit cost areas the areas where VDER providers are especially needed? As illustrated by NYSEIA and NineDot in their respective comments,[23] the example data set of utility MCOS estimates showed decreasing unit costs as the size of a project increases. Economies of scale within each segment are also illustrated in the utilities' June 30, 2025, MCOS filings.[24] To the extent that a VDER project can enter the market and survive, or even profit, with DRV plus LSRV set at a level below the MCOS for that area,[25] that VDER project should result in a savings of societal resources.

The Staff proposal is anchored in providing DERs the full, per kW/year value of the avoided distribution system cost with a meaningful price signal of the additional LSRV value to incentivize investments in higher than average cost areas. It might very well be the case that the LSRV project in an area cannot provide the full MW necessary to defer the traditional solution project. However, filling less than the entire MW need can still result in a deferral of the traditional project thereby providing societal value especially in outer years where load forecasts may change.

Appendix B also contains a table showing how Staff's proposed LSRV values compare with those currently in place, and also estimates the LSRV based on the Joint Utilities' and CEP's proposals if applied to the MW and corrected marginal cost estimates that were included in the utilities' June 30, 2025, MCOS study filings.

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[21] Currently the percentage of areas eligible for LSRV are 19%, 12%, 16%, and 0% Con Edison, ORU, NMPC, and CH, respectively. CEP February 26, 2025, comments, Table 1, p 5.

[22] By setting LSRV at this level, 95 percent confidence is achieved that the average MCOS of the LSRV areas is higher than the system wide average MCOS. However, to help ensure every LSRV substation area is a higher cost area, we will require each and every substation serving LSRV area have an MCOS value higher than this threshold. The statistical construct behind the setting of this threshold is further explained in Appendix D.

[23] See CEP February 26, 2025, comments, p. 14.

[24] See graph showing economies of scale in Appendix A.

[25] These costing relationships would change if the utilities were to switch to a cheaper, but less scalable technology for projects of a smaller size.

C. Definition of LSRV Areas

Staff's proposed identification of LSRV areas is based solely on the Value Stack Compensation Order's requirement that LSRV should be available in higher cost areas. Although that order also stated that "LSRV, available only in locations that the utility has identified as having needs that can be addressed by DERs," , we will discuss how utility planning needs can be addressed by DERs that meet certain dispatchability and reliability criteria regardless of the level of utility avoided in costs in the area where a DER project is located. Identifying the higher cost to the utility providing service in that area is the first step in determining how to identify an LSRV area. Staff proposes that LSRV areas be defined as those areas having MCOS values of greater than the system-wide average MCOS plus the LSRV, which is the system-wide average MCOS plus 1.645 standard errors. This methodology results in high confidence that each LSRV area has costs that are significantly higher than costs on average for all substation serving areas (i.e., higher than system wide average MCOS). As will be explained in the next section, just because a DER project is located in a significantly higher cost area does not mean that the project will be able to meet the utility's planning needs. Therefore, Staff is not proposing that all DER projects located in a LSRV area be eligible for higher LSRV compensation.

Appendix B also compares the number of LSRV substation areas for each company proposed by the JU, CEP and Staff.

D. LSRV Dispatchability and Reliability Terms and Conditions

As indicated earlier, DRV reflects system-wide MCOS because, under Staff's proposal, DRV can be collected for Value Stack resources located anywhere on the utility's system. However, in addition to reflecting a higher price signal, we propose that LSRV resources should exhibit the level of reliability and dispatchability that the utilities' planning engineers require to provide a capacity solution in those highest cost areas. The higher value of these resources should reflect their ability to avoid the need for high-cost traditional solutions.[26] In order to do that, certain performance characteristics must be met.

Contracts and tariffs are two possible methods to effectuate the non-price terms and conditions necessary to make LSRV projects sufficiently reliable and dispatchable for planning purposes in high-cost areas. The Value Stack Compensation order envisioned that such

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[26] We note that the value of a long run deferral value should equal long run marginal costs.

dispatchability and reliability terms and conditions be included in the filed VDER tariffs.[27] Demand response programs such as CSRP and DLRP rely solely upon tariffs with little in the way of contracting. The current LSRV also relies upon tariff language, but the relationship between the utility and the DER provider is analogous to a "one-way" contract as the utilities are required to stand by the terms and conditions in the tariffs, but the DER provider makes no similar commitment. In contrast, auto-DLM programs and NWA projects are selected via a competitive bidding process and result in program agreements or contracts being signed by both the DER applicant and the utility.[28] NineDot provides a helpful comparison of compensation mechanism designs for distribution-connected resources participating in various load relief programs.[29]

A standard contract, which spells out the necessary performance terms and conditions, could possibly be made available for LSRV resources. Such a standard agreement could have performance related terms and conditions specified in a manner similar to how they are laid out in DLM and NWA agreements and could point to the LSRV rate in the VDER tariff. However, given the relationship between DRV and LSRV, and since DRV being offered on a broad basis resembles a tariff service by nature, it would be more reasonable to spell out the added reliability and dispatchability terms and conditions in the VDER tariffs. This would also allow the additional requirements of LSRV over DRV to be more readily compared by the providers of VDER resources.[30] Appendix E to this proposal contains a high- level listing of those terms and conditions that we propose be included in the LSRV tariffs. Staff proposes that draft LSRV tariffs be filed within 45 days of the issuance of this whitepaper and be issued for comment by the Parties. These draft tariffs should only include placeholders for new LSRV price levels[31] as the Commission will decide on LSRV price levels and approve the new LSRV non-price terms and conditions at least 60 days subsequent to the filing of this Staff proposal.

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[27] Value Stack Compensation Order, pp. 16-19 and Ordering Clause 1.

[28] See, for example, the program agreement that Con Edison provides for potential Auto DLM program bidders. https://www.coned.com/en/business-partners/business-opportunities/dynamic-load-management-request-for-proposals

[29] NineDot, February 26, 2025, comments pp. 11-12.

[30] For example, for Con Edison, the language on these the added reliability and dispatchability terms and conditions would be added to Rider R of the tariff.

[31] Although it is important to note that the language of the tariff should ensure that there is no double-compensation for LSRV and DRV via other tariffs or programs.

CONCLUSION

The Intent of Staff's proposal is to set long run avoided cost based DRV and LSRV levels that will foster efficient competition and allow the utilities to rely on third party solutions in high-cost areas. However, in recognizing improvements could be made toward achieving this goal, parties are invited to comment on this proposal and to respond to the questions listed in Appendix F. Staff submits this proposal for public comment and Commission consideration.

Appendix A

Regulatory Economics Background

Why set VDER compensation at the level of long run avoided costs? [32] First, prices set at marginal costs maximize societal welfare in terms of the sum of consumer and producer surplus.[33] Economically efficient rate designs produce a level of demand that would come about if prices were set equal to long-run marginal costs.

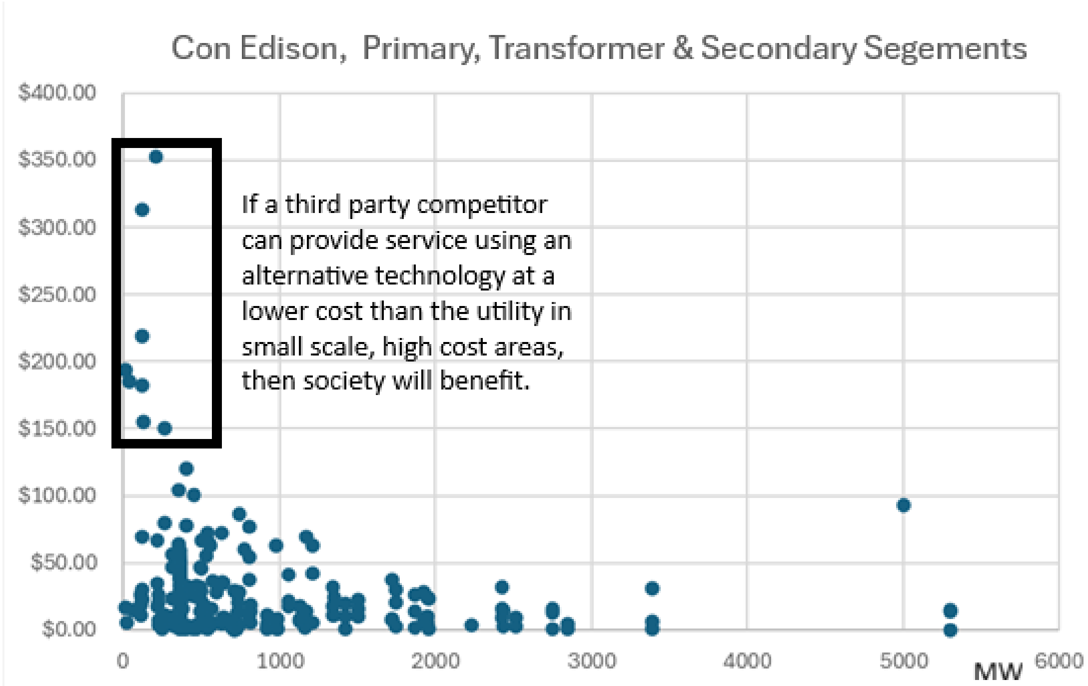
Second, VDER compensation set at the long run marginal cost of the utility will provide a price signal for efficient competitive entry by non-utility DER providers. The long-run equilibrium price for a competitive industry reflects prices set at long run marginal cost.[34] Thus, compensation based on long run marginal cost would provide a price signal for efficient entry by DER providers similar to the price signals that would be expected in a reasonably competitive market.

In short, VDER compensation set at long run marginal costs will promote the use of VDER resources based on the value of the societal resources which will be saved.[35]

Additional LSRV compensation is intended for limited high-cost areas and is designed to attract DER resources. To the extent that a VDER project can enter the market and survive or even profit with DRV plus LSRV set at a level equal to the MCOS for that area, that VDER project should result in a savings of societal resources. Utility MCOS estimates show decreasing unit costs as the size of a project increases within network segments.

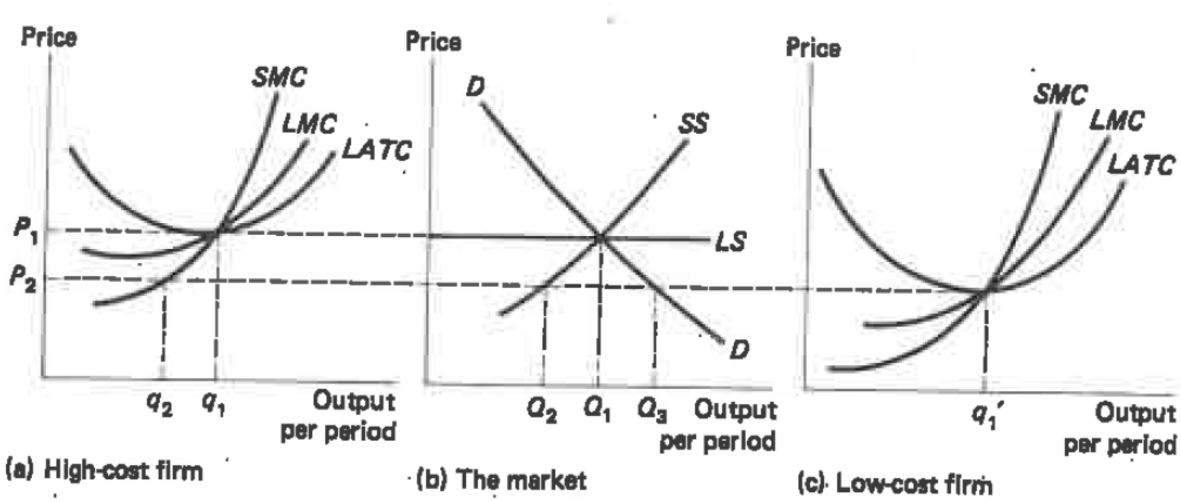
[32] See MCOS Whitepaper and MCOS order for more discussion on the reasonableness of using Long Run Marginal Cost (LRMC or LMC) as the basis for the pricing decisions in this proposal.
33 See NYPSC Opinion 76-15, Case 26806 - Proceeding on motion of the Commission as to rate design for electric corporations. Opinion and Order Determining Relevance of Marginal Costs to Electric Rate Structures, Issued: August 10, 1976, p. 7.
[34] In a competitive market, long run average total cost equals long run marginal cost as any higher-than-normal profits are competed away.
[35] NYPSC Opinion 76-15, p. 17.

Figure A-1



As competition takes hold, former market prices P_1 reflecting the costs of the higher-cost supplier should be driven down to the lower supplier's cost level at P_2, providing a benefit to consumers.

Figure A-2



Source: Walter Nicholson, Microeconomic Theory, Basic Principles and Extensions, Second Edition, page 335

Appendix B

Summary of DRV and LSRV Levels Under Staff's Proposal.

This appendix provides the results of Staff's proposed calculations of the LSRV and DRV for each utility. Also, provided is an identification of the number LSRV areas in each utility service territory. [36] Filed along with this Staff Proposal is an Excel spreadsheet file which calculates the LSRV and DRV using 10 year levelized MCOS figures calculated from the utilities' MCOS studies that were filed on June 30, 2025. Table B-1 contains Staff's DRVs and LSRVs.

Table B-1 **Staff's Proposed DRV and LSRV ($/kW-year)**

Utility	Non-Zero Cost Substation Area	DRV (Weighted Avg 10-yr Levelized MCOS)	Weighted Standard Error	LSRV (1.645 Weighted Standard Errors)	Substation Areas in LSRV Zone	DRV + LSRV
CECONY	46	252.54	32.04	52.70	2	305.24
Central Hudson	64	21.64	8.47	13.94	4	35.58
NYSEG	79	85.23	23.50	38.67	10	123.90
National Grid	151	146.59	19.41	31.93	35	178.52
O&R	59	22.73	7.29	11.99	7	34.72
RGE	46	66.85	12.04	19.80	9	86.65

[36] Staff notes that the number of LSRV areas might not total to 10 percent of the total serving areas. For example, if there are multiple serving areas with the same MCOS/kW-yr cost estimates, all or none of these "tied" service areas may end up in the LSRV area. Further, since the 1.645 standard error threshold relates to the expected mean of a twenty percent sample, some of the serving areas that are above that 1.645 standard error threshold could be from a skewed underlying distribution which has a median either above or below the mean of the sampling distribution.

Table B-2 shows Staff's proposed DRVs for each utility in comparison to the DRVs currently in the VDER tariffs. For comparison purposes, Staff also applied the DRV calculation methodologies that the JU and CEP recommended in their comments to Staff's weighted average systemwide levelized MCOS calculations.

Table B-2	**DRV ($/kW-year)**			
	Current	**JU**	**CEP**	**Staff**
Con Ed	199.40	126.27	252.54	252.54
Cen Hud	14.55	10.82	21.64	21.64
NYSEG	29.67	42.62	85.23	85.23
N. Grid	61.44	73.30	146.59	146.59
O&R	64.78	11.37	22.73	22.73
RGE	31.92	33.43	66.85	66.85

Table B-3 compares the results of estimating systemwide average MCOS using Staff's proposed averaging method versus the system-wide MCOS values the Utilities presented using their method of aggregating segment costs.

Table B-3	**Comparison of Segment Aggregation Methods for DRV ($/kW-year)**		
Utility		Staff Proposed DRV (Weighted Avg 10-yr Levelized MCOS) *	NERA Segmenting Method 10yr Levelized MCOS for Systemwide EE Purposes **
CECONY		252.54	367.37
Central Hudson		21.64	74.68
NYSEG		85.23	70.60
National Grid		146.59	233.12
O&R		22.73	87.73
RGE		66.85	98.03
* weighted average of sum of segment costs in areas with at least one segment having non-zero cost			
** sum of each segment's non-zero weighted cost			

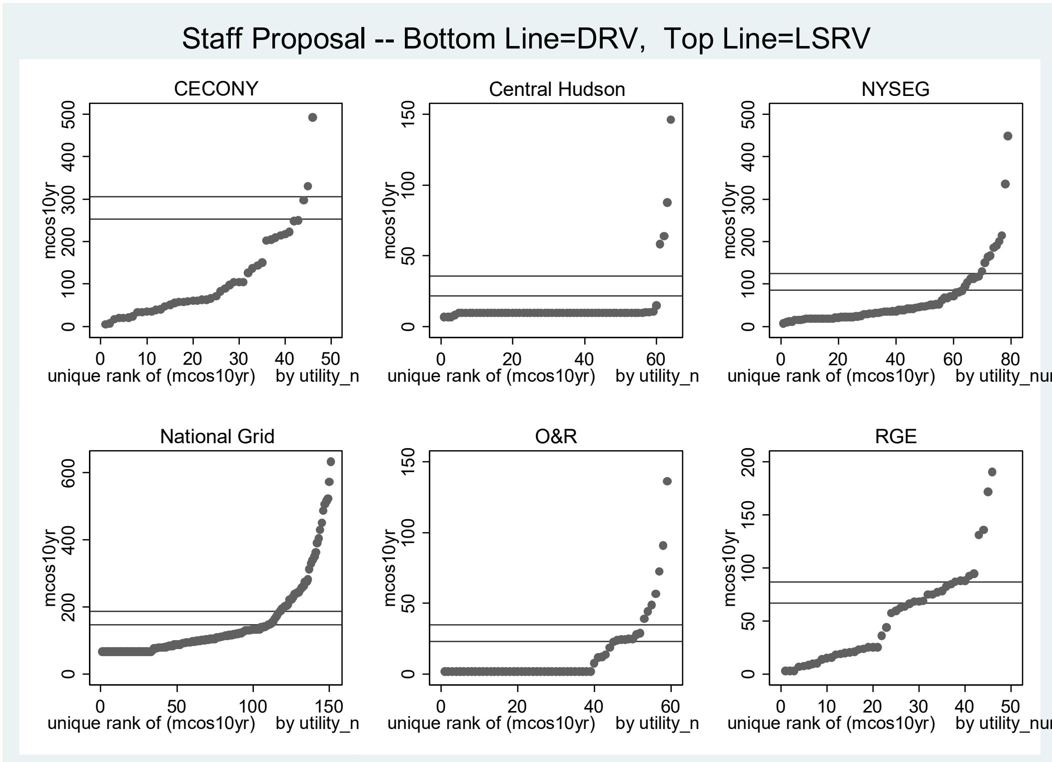
Table B-4 compares the LSRV levels in the current tariffs with those proposed by Staff for each utility. For comparison purposes, Table B-4 also shows the LSRVs developed using the methodologies proposed in the JU and CEP comments as applied to Staff's calculation of the MCOS estimates.

Table B-4	**LSRV ($/kW-year)**			
	Current	**JU**	**CEP**	**Staff**
Con Ed	140.76	31.57 or 63.13	TBD	52.69
Cen Hud	N/A	2.7 or 5.41	TBD	13.94
NYSEG	53.59/56.26	10.65 or 21.31	TBD	38.67
N. Grid	30.72	18.32 or 36.65	TBD	31.93
O&R	39.61	2.84 or 5.68	TBD	11.99
RG&E	47.96/9.47	8.36 or 16.71	TBD	19.8

Table B-5 contains a comparison of LSRV levels and LSRV substation areas for each company proposed by Staff. Also shown are the JU, CEP LSRV eligibility areas using the methodologies proposed in the JU and CEP comments as applied to Staff's calculation of the MCOS estimates.

Table B-5	**LSRV Eligibility**					
	JU		**CEP**		**Staff**	
	LSRV Zones	LSRV Substation Areas	LSRV Zones	LSRV Substation Areas	LSRV Zones	LSRV Substation Areas
Con Ed	2	11	TBD	TBD	1	2
Cen Hud	2	4	TBD	TBD	1	4
NYSEG	2	23	TBD	TBD	1	10
N. Grid	2	35	TBD	TBD	1	35
O&R	2	16	TBD	TBD	1	7
RG&E	2	23	TBD	TBD	1	9

Figure B-1 Ten Year Levelized MCOS Results
Substation Areas Stacked by $/kW-yr Costs



Appendix C

Staff Changes to Utilities' Marginal Cost Study Results

All Utilities

- Did not turn investment amounts to zero subsequent to a project going into service (an option presented in a few of the MCOS studies. Used cumulative amounts per "In Service Projects" section of August 2025 MCOS order, pp 46-47). See the second to last tab in Staff's workpaper spreadsheet file for an example showing that this treatment of cumulative investment amounts produces costs which recover the revenue requirement of the investments.
- Did not adjust for differences in project costs and timing between MCOS study filings and rate case filings.
- Calculated weighted average costs for each segment across all substation areas that had non-zero costs in at least one segment. See the last tab in Staff's workpaper spreadsheet file for an example showing that this calculation of segment costs produces rates which recover the revenue requirement of the investments in substation areas in which at least one segment has non-zero costs.

Con Edison

- Corrected double application of inflation factor.
- Levelized individual substation MCOS estimates to produce a 10-year levelized cost for each substation. Levelized using WACC based discount rate listed in the Con Edison workpapers.

Central Hudson

- Allocated 326 MW of added system wide transmission capacity to 63, substation areas, or 5.17 MW of transmission capacity allocated per substation.
- Used rough allocator since existing MW per substation not readily available in workpapers.

National Grid

- Corrected National Grid's filed calculations to only include 10 years of capital projects from 2026 through 2035 as opposed to the projects from 2026 to 2036 as originally presented by National Grid. Thus, Staff removed the 2036 in-service projects from the study.
- Allocated 4053 MW of added system wide transmission capacity to 151, substation areas, or 26.84 MW of transmission capacity allocated per substation.
- Used rough allocator since existing MW per substation not readily available in workpapers.
- Allocated project level costs and kW to a substation serving area level to create a substation serving area MCOS.

Levelized individual substation MCOS estimates to produce a 10-year levelized cost for each substation. Levelized using WACC based discount rate listed in the National Grid workpapers.**NYSEG**

- Refiled Corrected results 7-11-25. Corrected for double counting of substation results.
- Unlocked, corrected studies filed on 8-14-25.

Orange & Rockland

- Corrected double application of inflation factor.
- Levelized individual substation MCOS estimates to produce a 10-year levelized cost for each substation. Levelized using WACC based discount rate listed in the Orange & Rockland workpapers.
- Corrected for the Wisner Substation mistakenly having the same MCOS as the Wurstboro substation. The formulas in the total MC tab of the Orange & Rockland workpapers incorrectly call Wurstboro numbers for Wisner.

RG&E

- Refiled Corrected results 7-11-25. Corrected for double counting of substation results.
- Unlocked, corrected studies filed on 8-14-25.

Appendix D

Statistical Background

A statistical framework can be used to determine which substation areas have higher costs. This framework is based on the assumption that high- cost areas should represent ten percent of all non-zero cost substation service areas.

Statistical procedures can be used to compare high cost and lower cost areas. Statistical procedures recognize the randomness associated with processes and the measurement error associated with recording the results of those processes. Thus, comparative procedures that are based upon generally accepted statistical procedures can be used to analyze the costs associated with Utilities' construction and operational processes since those processes, and their measurement, contain some degree of randomness. Statistical procedures recognize measurement variability and can assist in translating the resultant MCOS data into useful decision-making information. Thus, a statistical approach allows for measurement variability while controlling the risk of drawing an inappropriate conclusion (i.e., a Type I or Type II error).[37] As described in the body of this document, high utility cost areas likely have features, such as economies of scale, which result in the project construction costs being higher in certain areas.

The statistical framework is based on the question - if another twenty percent sample of construction projects were to come along, what would the mean of that sample have to be to achieve 95 percent confidence that the higher cost sample of investment projects did not come from the design and construction process that generated the low-cost sample? This framework is based on standard statistical testing which assumes a normal distribution of sample means.[38]

To achieve 95% confidence that, on average, costs are higher in LSRV areas, Staff proposes a one-tailed test using a standard error based on a twenty percent sample of the MCOS study projects for each utility. The threshold for defining the LSRV is set to reflect 1.645 standard errors above the system-wide average MCOS. Staff proposes to include in LSRV zones only those substation areas that have costs higher than the 1.645 standard error threshold to ensure all LSRV substation areas have higher costs.[39] In other words, since approximately half of the high-cost sample would have costs above the twenty percent sample's mean, Staff

[37] See Local Competition Users Group document "Statistical Tests for Local Service Parity" dated February 6, 1998, and filed in Case 97-C-0139 – Proceeding on Motion of the Commission to Review Service Quality Standards for Telephone Companies.

[38] It might be possible to utilize an alternative statistical framework. For example, a non-parametric, re-sampling framework could repeatedly take random samples of the combined size of the set of low-cost and high-cost projects in the study, either with replacement (bootstrap) or without replacement (permutation) to estimate the level of cost in excess of the highest 10% of the combined resamples. However, such a resampling-based approach would be administratively more difficult going forward.

[39] In this instance, a Type I error would be associated with concluding that costs for a substation area are associated with a higher cost process when they are not. A Type II error would be associated with failing to conclude that a substation area's costs are from a higher cost process.

proposes using the 1.645 standard errors (i.e., standard deviations of the sample mean) as the threshold for defining LSRV areas. This should result in roughly 10% of substation areas being included in LSRV areas.

Appendix E

Non-Price Level Terms and Conditions to be Included in the LSRV Tariffs

Staff proposes that language detailing the requirements for the following non-price level terms and conditions be included in the LSRV portion of the VDER tariffs.

Specification of the Amount of Load Relief Eligible for LSRV

Duration of the LSRV Load Relief Obligation by the LSRV Project

Duration and Timing of the Dispatch Events Callable by the Utility to Provide Load Relief

Metering and Communications Equipment and Protocols Required for the LSRV Provider

Installation Requirements for the LSRV Project

Performance Testing Under Test Events

Penalties for Failure to Perform Under Called Events

Early Termination of Obligation Penalties

Restrictions on Operating in Other Load Relief Programs

Force Majeure Clauses

Appendix F

Questions for Comment

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?
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?
3. How will this proposal affect other planning processes such as (CGPP, PPP, etc.)
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?
5. What specific language on non-price terms and conditions should be enumerated for LSRV eligibility?
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.
7. National Grid included transmission projects in their MCOS study. Page 44 of the August 2025 MCOS order requires that Commission's directive that the costs of all growth-related transmission projects, including FERC regulated transmission projects should be estimated in the study to best inform the Value Stack. However, National Grid did not designate which transmission projects were bulk federal tariff related which were local NYPSC tariff related. Therefore, Staff could not split the federal tariff related component out of the 10-yr levelized MCOS figures that staff used to determine its proposed DRV and LSRV levels. Thus, the National Grid costs should be viewed as over-statements of NYPSC jurisdictional costs, but not of the totality of long run avoidable costs. How should this issue be handled in any possible revisions of the National Grid and other Joint Utilities MCOS studies?