RE: Case 15-E-0751; Response to Staff Questions for Comment on Calculating Locational System Relief Value (LSRV) and Demand Reduction Value (DRV) to Inform Pricing

November 22nd, 2024

Dear Secretary Phillips,

The Clean Energy Parties (CEP), a coalition of clean energy trade associations and member companies active in New York[1], submit the following comments in response to the Staff questions regarding DRV and LSRV submitted on October 25th, 2024 in Case 15-E-0751.

1. **What are the appropriate design criteria for LSRV and DRV values (e.g., stable, long run, etc.)?**

DRV and LSRV are long-run price signals used to compensate eligible technologies for their value in avoiding or deferring traditional utility solutions. These values must be stable, predictable, transparent, and derived over a time period that reflects timeframes used by utilities for long term system planning and by infrastructure investors evaluating Distributed Energy Resources (DERs). The CEP are supportive of Staff's position that a longer-run cost analysis has the ability to recognize considerable changes in utility load that could be sustained by DER resulting in potential deferrals of utility investments.[2] In summary, the creation of a price signal that appropriately values the ability to avoid incremental investments in new transmission and distribution infrastructure due to DER output during peak system load hours is the design objective of the DRV and LSRV.

Projects on the Value of Distributed Energy Resources (VDER) tariff are avoiding investments that would be amortized by the utility over decades. A long run stable price signal is provided for the utility to make these investments. DER's avoiding these investments should similarly be afforded long run certainty. As a practical matter, VDER assets typically having useful lives of 20+ years and financing terms of 10+ years, it is crucial that the value stack have compensation structures that are transparent and understandable to a wide range of stakeholders including DER developers and financial institutions that provide capital to VDER projects. The design criteria must result in a structure that is perceived as low risk by investors where if the DER asset performs as expected, cash flows will be predictable. While the wholesale energy and capacity values may fluctuate, the DRV and LSRV values must be stable and predictable to provide the investor community with a sense of security.

[1] The CEP is a group of aligned commenters including the Solar Energy Industries Association, the New York Solar Energy Industries Association, New York Battery Energy Storage Technology Consortium, the Coalition for Community Solar Access, the Alliance for Clean Energy New York, and Advanced Energy United.
[2] Case No. 19-E-0283, Whitepaper Regarding Marginal Cost of Service studies, 3/27/2023, p. 10

2. **Should LSRV and/or DRV values be algebraically derivable from the MCOS studies that will be filed in June 2025? Otherwise, should LSRV and/or DRV be guided by those MCOS studies?**

   Utility Marginal Cost of Service (MCOS) studies should underpin any evaluation of the benefits to the transmission and distribution system that are attributable to DERs as load modifiers. The benefits to the transmission and distribution system, or in other words the value of demand reductions at peak times, should be valued based on the MCOS. This aligns with the interests of ratepayers as the payment should be commensurate with the relative benefits of DERs and their ability to defer or avoid incremental investments in the distribution system that the ratepayer would otherwise have to bear in the form of embedded costs in distribution base rates.

   The MCOS values must be translated into a price signal somehow and an algebraic methodology is preferable due to its transparency. In the provided Appendix, the CEP have included a proposal for the how LSRV price signal can be determined. It also includes a proposed methodology to adjust the system wide MCOS by removing the quantity of designated LSRV capacity to derive the DRV. If the MCOS is to be updated biennially as planned, an algebraic method included in workpapers accompanying compliance filings with a defined set of inputs and variables can be studied by market participants. These market participants, including DER investors, can use an algebraic methodology and data in the workpapers to identify the variables and linkages in the DRV and LSRV cost calculations and extrapolate how future changes could impact payment levels. DER developers could also use the substation area load forecasts in the MCOS studies to better forecast the potential for project viability such as in scenarios where an early-stage project may not be able to secure a DRV or LSRV reservation until the next update cycle. The ability to accurately predict future VDER compensation is also critical for New York State Energy Research and Development Authority (NYSERDA) and New York State Department of Public Service (DPS), so the agencies can set appropriate capacity-based incentives for DERs that contribute toward the Climate Leadership and Community Protection Act (CLCPA) and other public policy objectives. A successful and durable future DRV and LSRV regime with regular updates cannot be a black box and an algebraic method provides the best opportunity for transparency.

3. **It has been mentioned that the traditional MCOS study does not average in any areas with no projects (i.e., areas with zero costs); please reconcile this statement with the indication in Con Edison's 2012 MCOS study which assigns zero weight to such areas. Should the 2012 report be read to indicate that the avoidable costs of zero in areas with excess capacity will not be averaged into the results of the study, or that the avoidable costs of zero in areas with excess capacity will be included in the resulting weighted average result?**

   The National Economic Research Associates (NERA) methodology notes that if there is long term excess capacity in the system or segment, then marginal cost may be zero. In its whitepaper, Staff rejects the use of a short-run headroom analysis as a rationale for claiming zero marginal costs explaining that such an approach is inconsistent with the needed "run" and time horizon given New York's aggressive electrification initiatives.[3] If Staff's method is followed and an area is still forecasted to have significant headroom, then it would be reasonable for that area to contribute a marginal cost of zero.

That said, with increased electrification and uncertainty surrounding levels of demand growth, it is unlikely that many areas would have a marginal cost of zero during the entirety of the 10-year study period.

4. If a traditional solution is only deferred for a few years, and not deferred for a 10-year planning period or more, should a different price signal be provided?

The selection of a price signal should depend upon the resources needed and planning period use cases. Short term immediate reliability needs, if addressable with DERs, could be use cases for Non-Wires Alternatives (NWA) or Dynamic Load Management (DLM) solicitations. NWAs and DLM rely upon location specific price signals which are based on the costs of a traditional utility upgrade. In these instances, DERs providing capacity are competing against specific and known capital costs of a distribution system expansion and these costs serve as a benchmark to determine if an NWA or DLM product will be cost effective.

The purpose of LSRV is to act as a steering mechanism[4] to direct investment to areas where DERs can provide a capacity product to satisfy needs that are emerging in a four-to-ten-year timeframe. The use case of the LSRV product is not a short-term deferral, but a longer-term mechanism to attract distribution capacity resources to areas experiencing moderate and predictable load growth. As a result, a value derived from the MCOS study is appropriate for this use case instead of a short-term price signal to value location specific needs. From an investment perspective, a 10-year planning period is needed for a VDER project to be financeable and while it is possible that an LSRV zone may subsequently require an NWA or a capital upgrade, DERs receiving LSRV must be able to rely upon their 10-year lock-in period, otherwise they cannot be financed and constructed; the same certainty is provided to the utility for the investment they would otherwise make. A longer planning period also helps account for rapid changes to the distribution system in response to CLCPA objectives.

5. How should the level of the price signal and the years of deferral be optimized?

The number of years for which a DER can provide a deferral value can only be known in hindsight, much in the same way that a utility may increase capacity only to see loss of load in coming years. Load forecasts are subject to change as are construction project development timelines for DER projects.[5] As a result, the actual deferral period for which a DER provides value to ratepayers can be estimated prospectively, but not known with perfect accuracy. Nonetheless, an estimate of the deferral period is necessary to evaluate NWA projects against traditional system upgrades.

---

[3] Id., p. 16

[4] Case No. 15-E-0751, Order Regarding Value Stack Compensation, 4/18/2019, p. 17

[5] See NWA table in response to Question 8

The New York State Public Service Commission (Commission or PSC) has expressed its preference that "the Joint Utilities rely upon probabilistic demand forecasts for distribution planning."[6] The optimization of the price signal should incorporate the use of probabilistic demand scenarios to determine the range of potential deferral value outcomes. This range should then be used to inform the price signal. Doing so would incorporate optionality into the analysis since high, low, and base case deferral value scenarios can be assessed. As stated in the August MCOS Order, "Given the increased uncertainty regarding load growth, Staff recognizes the ability of probabilistic demand forecast based distribution planning to have the flexibility to consider the potential for high-cost and low-cost outcomes, and the associated value of this optionality in capital planning."[7] Therefore, a simple average or midpoint of expected scenarios is not a sound method to determine the price signal, but instead an evaluation of a range of probable outcomes.

As stated previously, a location specific deferral value is not an appropriate price signal for LSRV, but is useful for evaluating NWA and DLM projects.

6. **How should the possibility of load transfers, as opposed to a deferral of a specific larger capital project, factor into the level of LSRV compensation?**

CEP is supportive of the least cost way to manage load growth and believes that load transfers should be utilized in scenarios where they are a viable option. That said, load transfer solutions must be considered alongside a 10-year planning horizon that incorporates load growth estimates that are aligned with New York electrification policies and the guidance from the Commission in its August 2024 Order. Load transfers allow utilities to improve system resiliency by isolating problem areas, but grid sectionalization in response to load growth is a short-term solution in the face of sustained load growth. While the CEP are supportive of the use of load transfers in general, they disagree with Central Hudson's historical argument to exclude local distribution level costs from MCOS calculations.[8] The Commission has provided clear guidance for the conduct of MCOS studies in its Order and the Joint Utilities (JU) would need to provide compelling evidence supporting its ability to avoid feeder level costs via load transfers in long-run scenarios conducted per the MCOS guidance.

7. **How do deferral values and/or avoided costs differ in cases where project costs are not as lumpy as others?**

In areas where project costs are known and predictable with good certainty, there is greater confidence in avoided costs and/or deferral values. A very lumpy capital project cost can greatly swing a deferral value if the timeline for those costs are moved in either direction. There is a confidence range in the validity of deferral values calculated for NWA projects, with the highest confidence for projects with steady load growth trends and moderate capital costs for traditional utility solutions. At the other end of the confidence spectrum are sites with uncertain or highly variable load growth scenarios that require a

[6] August 19, 2024 Order at 30
[7] Id., p. 29
[8] Id., p. 40

large capital investment at a point in time that is subject to change materially based on how load growth materializes. These two projects could have the same calculated deferral value, but they are not equivalent due to the variations in the confidence that the projections will actually be borne out. This risk in confidence in the deferral calculation ties back to the concept of optionality. With uncertainty around load growth increasing, there is an imminent need for optionality in capital planning. Specifically, asset owners must consider both high-cost and low-cost outcomes and be able to adjust assets to respond to different use cases.[9]

As discussed above, the two deferral calculations described above can arrive at the same number, but the lumpy project has a lower confidence of being realized and carries the risk of a false precision due to the greater variability in the project's time estimates for when lumpy capital expenditures would occur. Assuming that the scenario with the lumpy capital expenditures and uncertain timelines is appropriate for an NWA, the use of probabilistic forecasting to look at high-cost outcomes should inform the valuation as opposed to lower cost load growth scenarios since a cost-effective NWA solution offers a hedge value against uncertain costs.

8. **At the technical conference on October 1, 2024, the Joint Utilities (JU) stated that once a Non-Wires Alternative (NWA) portfolio is established or construction starts on a new utility capital project, deferral is no longer an option. Please comment.**

Whether or not deferral is an option depends on the scale of the capital project. In instances where a substantial upgrade is needed, it is less likely that there will be a separate deferral opportunity. However, there is no reason to believe that a NWA or small scale capital project can't be paired alongside a VDER asset with the shared purpose of delaying larger upgrades.

Additionally, review of past and ongoing NWA projects suggests that variability in deferral timelines is to be expected and that many NWA resources come online in phases and are oftentimes not fully operational by the initial "need-by" date (see Table 1 below).

[9] Case No. 19-E-0283, Whitepaper Regarding Marginal Cost of Service studies, 3/27/2023, p. 26

Table 1: Summary of Selected NWA Projects[10]

Utility	Project Name	Approx. Relief Needed (MW)[1]	Initial Need-by Date	Initial RFP Date	Initial DER Online Date[2]	Elapsed Time (~yrs)	Project Status
O&R[3]	West Warwick[4]	12	2022	Sep-19	2023	4	Energized
O&R	Pomona[5]	3	2020	Dec-17	2021	3	Energized
Central Hudson[6]	Fishkill[7]	5	2018	Nov-14	~2019	5	Active Implementation
Central Hudson	Northwest Corridor	10	2019	Nov-14	~2019	5	Active Implementation
Central Hudson	Merritt Park	1	2019	Nov-14	~2019	5	Active Implementation
ConEd[8]	Water St[9] / Plymouth St	14	2021	Oct-17	2021	4	Energized
ConEd	Newtown[10]	10	2021	Jul-18	~2019	1	Active Implementation
ConEd	BQDM Program[11]	52	2018	Jul-14	~2015	1	Active Implementation
NYSEG	Stillwater Storage Project[12]	1	2022	Dec-17	2023	5	Energized
National Grid[13]	Pine Grove	10	2021	Nov-18	2022	4	Energized
National Grid	Watertown	5.7	2022	Nov-19	2024	5	Active Implementation

[10] Footnotes included in Table 1 are summarized below.

1. The required capacity sometimes increases stepwise over the NWS term.
2. Some projects have staggered online dates which impact deferral value calculation methods.
3. See Case 16-M-0411, Orange & Rockland's (O&R) Distributed System Implementation Plan (DSIP) Update, 6/30/2023, pp. 196-197 – Table 14 details Currently Identified Company NWA Projects and the "NWA Projects" section below provides project updates.
4. See the West Warwick Project Description located on O&R's NWA Webpage for the initial need-by date; p. 64 of O&R's 2023 DSIP Update confirms project status.
5. See Case 16-M-0411, O&R DSIP Update, 6/30/2020, p. 212, Table 25 for Pomona's initial need-by date.
6. See Central Hudson's NWA Opportunities Webpage identifies current NWA opportunities and details.
7. See Case 16-M-0411, Central Hudson DSIP Update. 6/30/2023, p. 282 – Table 46 provides load reductions available as of January 2022 for the Fishkill, Northwest Corridor and Merritt Park projects, all of which are part of Central Hudson's Targeted Demand Response Program.
8. See Case 22-E-0064, NWS Quarterly Expenditures and Semi-Annual Program Report, 11/29/2023, Appendix A: NWS Portfolio History to Date, pp. 12-17
9. See Case 16-M-0411, Consolidated Edison (ConEd) DSIP Update, 6/30/2023, p. 170 – notes that Water Street Implementation was completed in 2023.
10. Newtown Energy Efficiency (EE) program implementation began in 2019 & an energy-storage Request for Proposal (RFP) was announced June 14, 2019; contracted storage is expected to be operational in 2024 (see page listed for bullet #9 above).
11. The initial Request for Information (RFI) for ConEd's BQDM program was issued in July 2014; the BQDM Extension program began in 2018 (see appendix cited in bullet #8).
12. See Case 16-M-0411, New York State Electric and Gas (NYSEG) and Rochester Gas & Electric (RG&E) DSIP Update, 6/30/2023, p. A. 1-3
13. See Case 20-E-0380, National Grid NWA Status Report – Q3 2023, 11/29/2023, pp. 3-7

9. **Are there situations in which the cost of the traditional utility capital upgrade, or the cost of the NWA, decreases as Distributed Energy Resources (DERs) are deployed?**

   Yes. LSRV, when properly operationalized, is a longer-term steering mechanism that does not need to fully eliminate constraints in a given area to be effective. DERs in LSRV zones may fully offset certain projects or they may result in lower cost capital projects or NWAs in the future. For example, O&R's 2017 Implementation Proposal notes that MW caps are determined by identifying the amount of load relief that would be required to bring LSRV areas into alignment with design standards or to operate constrained areas at improved capacity and thermal operating levels. The CEP proffer that the MW cap approach discussed by O&R may not necessarily represent the amount of load relief needed to defer traditional investments and can be adjusted downward if additional reductions are procured through other price signal mechanisms such as NWA solicitations.[11]

   In the Appendix, the CEP have provided a proposed methodology to select the amount of LSRV capacity, by substation area, that would be needed to provide reliability benefits to the distribution system. The CEP's proposed method provides a mechanism to right size the LSRV procured with system needs and biennial refreshes ensure that the amount of LSRV required is assessed as load trends from electrification emerge.

10. **Given that NWAs are provided a long run price signal consistent with their longer-term contractual arrangements, and also given that NWA projects have performance clauses in their contracts, should NWA projects be given a higher compensation level than LSRV compensated projects that do not have similar time and performance commitments?**

    Not necessarily as NWAs and LSRV projects are not meant to accomplish the same thing. While NWAs are provided a long run price signal, they are meant to provide utilities with increased reliability in the near-term, and there is still a great deal of uncertainty regarding the lifespan of NWA projects and actual in-service dates. The performance clauses included in NWA contracts are needed to help ensure short-term needs will be addressed. LSRV on the other hand should be a long run price signal with the purpose of "animating" markets and steering DERs to the areas where they are most valuable.

11. **Please discuss how NWA and LSRV projects are incorporated into the utilities' capital plans.**

    When properly employed, NWA and LSRV projects can defer capital investments that would otherwise be included in capital plans, providing ratepayer savings.

12. **If the Weighted Average Cost of Capital (WACC) decreases relative to the forecast of inflation, the deferral value of a capital investment project will go down, all else equal. This is a Staff concern given supply chain shortage related impacts on input prices. Does using the most recent authorized WACC, as established in rate proceedings for discounting, reasonably reflect the uncertainty associated with fluctuations in inflation forecasts?**

[11] Case No. 15-E-0751, Implementation Proposal for Value of Distributed Energy Resources Framework, p. 4

The most recent authorized WACC does not reflect the uncertainty associated with fluctuations in inflation forecasts. The JU are able to respond to inflationary forces by filing rate cases to adjust their revenue requirements to fully recover their prudently incurred costs. DERs receiving locked-in NWA payments do not have this ability and a high inflation environment poses the risk of eroding the value of fixed payment streams while they are simultaneously exposed to higher operating costs. The relationship of WACC relative to inflation is in part a function of the view of capital markets in the cadence and outcomes of rate cases. All else equal, a longer time period between rate cases or regulators sharply slashing requested revenue requirements should result in higher WACCs as utilities would bear greater exposure to inflation risk, especially in business environments with high uncertainty regarding future inflation.

On the other hand, the benchmark for evaluating the value of a deferral to ratepayers is a comparison against the traditional utility solution whose revenue requirement would be determined by WACC. The Commission must balance the need to ensure cost effective solutions for ratepayers with a fair evaluation of DER project economics and comparisons to actual deferred investment at a future date.

It is likely that adjustments to WACC as the discounting factor may be controversial and difficult to derive. As an alternative, the Commission could require the deferral forecasts include escalation factors for traditional utility solutions that are reflective of current inflation and supply chain challenges. These forecasts may vary by project, but if a traditional utility solution deferral begins in year three, the costs of that solution should be adjusted to reflect likely inflation scenarios for the components of the solution in that year and the years thereafter for the expected life of the NWA. This method could effectively capture the inflation risk without requiring use of a new or modified discount factor.

In this increasingly uncertain energy business environment, one thing is certain and that is capital upgrades to the utility system will cost more in the future than they do today. An evaluation method that undervalues DERs and understates the risk of reactive fast track utility capital upgrades needed for reliability sets the stage for increased ratepayer costs. The MCOS guidance in the August Commission Order rightly moves towards a longer planning horizon to mitigate the risk of a short-term marginal view that systemically undervalues the benefits of DER relative to the costs of future distribution capital projects that could have been avoided.

13. **Should differences in how the DER market can react to price signals as opposed to the circumstances of a particular load pocket be taken into account when setting LSRV and DRV values? Discuss the trade-off between precision in determining deferral value and providing a price signal that the DER market can respond to.**

Low interconnection costs and restrictive local laws are currently the only steering mechanisms for DERs, and a clear price signal is needed to achieve New York's policy goals and drive investments. The 2019 Order notes that locational price signals are an important component of VDER and cannot sufficiently be replaced by Demand Response (DR) programs or NWAs.[12] Determining location-specific

[12]Case No. 15-E-0751, Order Regarding Value Stack Compensation, 4/18/2019, p. 17

deferral values lacks the transparency needed for the market to be able to properly respond and creates a risk of false precision should load growth exceed expectations or not materialize.

In addition, it is unclear how deferral values would reflect non-jurisdictional charges like avoided transmission costs, and commingling deferral values and marginal costs in a DRV de-averaging formula would likely create issues as the two values are materially different from each other (see Table 2 below).

Table 2: Key Differences Between Deferral Values and Marginal Cost

	Deferral Value	**Marginal Cost**
Time Period	Short-run	Long-run
Trigger	Near term location specific needs that are on the edge of the utility capital plan	Cadence of updates for MCOS studies
Use Case	Comparison of a site-specific traditional utility capital upgrade versus available NWS technologies	Long run price signal to attract DERs to locations so that some number of future utility capital projects never materialize due to the ability of DERs to suppress or modify load growth patterns

14. Discuss the importance of achieving consistency in how each utility uses their load forecasts for capital planning versus consistency in the methodologies used by each utility in developing their load forecasts.

While each of the JU are different and there will be some differences in load forecasting and capital planning, it is important that best practices be shared and the learnings from the Coordinated Grid Planning Process be adapted to each utility's circumstances. The EDCs should be able to demonstrate that their planning for growth related capital projects are grounded in load forecasts and sufficiently rigorous to anticipate future load growth over the next several years based on information that is currently available such as development patterns, commercial customer growth, and consumer adoption trends of electrification technologies.

ConEd's Idlewild Project at the Jamaica Distribution Area Substation in response to general economic growth, the electrification of logistics operators proximate to JFK Airport, and the electrification of the MTA bus fleet[13] is just one example of the increased uncertainty surrounding load growth patterns. While the Company's 2018 MCOS study performed by The Brattle Group identified the Jamaica substation area as a high marginal cost area, its assigned value was still significantly lower than other areas where load has not since materialized as predicted.[14] For reference, the Jamaica load area was valued at $147/kW-yr, while other load areas such as Long Island City and Flushing had marginal costs of

[13] Case 22-E-0064, Petition of Consolidated Edison Company of NY for Authorization and Cost Recovery for the Reliable Clean City – Idlewild Project, 8/22/2023, p. 4
[14] Case 15-E-0751, Marginal Cost of Service Study, prepared for ConEd by The Brattle Group, 7/30/2018, Tables 13d and 14d

$508/kW-yr and $435/kW-yr, respectively. Additionally, ConEd's decision to build a 300+ MW asset in response to a 52 MW immediate need indicates they are looking beyond the 10-year planning horizon of the MCOS studies.[15] Consistent updates to MCOS studies paired with more comprehensive load forecasting should help identify emergent system needs with sufficient lead time to attract DERs and delay capital upgrades. Commission action to require greater consistency in growth driven capital planning may only be warranted if a utility demonstrates a pattern of being caught off guard by load growth that necessitates reactive capital upgrades on a short notice.

The August Order provides clear guidance on load forecasting methods and relies upon the DSIP process as well as management and operational audits to ensure that load forecasting methods are robust. The Order allowed each EDC to continue to use their own load forecasting method and added a requirement that each utility include a discussion regarding how "longer-term projections for electrification, rising temperatures, and extreme weather events are incorporated into their load forecasts."[16]

The CEP recommend the addition of one supplemental item to the guidance from the MCOS Order to improve the rigor of the required discussions supporting the EDC load forecasts and to create some uniformity amongst the JU in how they incorporate state energy policy into their load forecasts. The State of New York has devoted considerable resources to energy sector modeling as part of the Scoping Plan.[17] The Scoping Plan relies upon multiple upstream studies that are used as inputs and calculated outputs in the Integration Analysis modeling conducted by NYSERDA. The reference case scenario data in the Integration Analysis Modeling is updated approximately annually by NYSERDA and includes scenario driven reference cases for peak electric demands and total electric loads.[18] The EDC load forecasts should include a cross reference of peak demand and load trends by New York Independent System Operator (NYISO) zone to the Reference Case study or successor study and provide a detailed quantification of any material differences.[19] Divergence between the EDC load forecasts and the reference case may be justified, but should be explained and supported.

In the event that EDC load forecasts are uniformly lower than those provided in the Integration Analysis Modeling reference cases or subsequent modeling conducted per the State Energy Plan, the Commission should require the use of a scaling factor to load forecasts for the purposes of conducting MCOS Studies to ensure that state policy is being fully considered and that any gap between utility load forecasts and state sponsored studies is narrowed. This comparison of studies is important to stress test utility assumptions and also to ensure that MCOS studies fully capture state policy trends and ensure that DERs don't find themselves in a "missing money" situation where an under-forecast of load growth

---

[15] Case No. 22-E-0064, Petition of Consolidated Edison Company of NY for Authorization and Cost Recovery for the Reliable Clean City – Idlewild Project, 8/22/2023, p. 2

[16] August 19, 2024 Order at 23

[17] https://climate.ny.gov/resources/scoping-plan/

[18] Reference Case 2023 Annexes, available at https://www.nyserda.ny.gov/About/Publications/Energy-Analysis-Reports-and-Studies/Greenhouse-Gas-Emissions

[19] The forthcoming New York State Energy Plan, currently in development, may also include rigorous forecasts of trends in electric loads per Section VI.i of the Draft Scope released in Sept 2024, available at https://energyplan.ny.gov/

results in an artificially low DRV and LSRV value that suppresses DER development. If load growth does end up exceeding forecasts, DERs will have missed an opportunity to meet load growth due to an inaccurate price signal and traditional utility solutions will have the advantage. As a result, a scaling factor to adjust load forecasts to reduce the gap, if present, between state sponsored load forecast studies and EDC load forecasts is necessary.

Since the MCOS studies are proposed to be updated every two years, load forecasts can also be dynamically updated with new information. The New York State scoping plan will be updated every five years with interim updates to the Integrated Analysis Modeling conducted in the interim by NYSERDA. As a result, any inaccuracies in modeling, by either party, should eventually be corrected as new data becomes available.

15. As the Dynamic Load Management program is an alternative to NWA and LSRV, should its 3- to 5-year time-frame also be included in this conversation?

Similar to LSRV, the DLM program is an important mechanism with operational shortcomings hindering its effectiveness. In practice, DLM is designed to address near-term needs by providing additional revenues to assets already in the planning or development phases. While DLM projects address needs in specified networks and load areas, the characteristically short duration of the program prevents it from being a sufficient steering mechanism that can support new build assets on its own. That said, the DLM program was not created to attract new projects to certain load areas with the goal of avoiding or deferring traditional solutions, but instead to address distribution level grid conditions during times of acute need.[20] Due to the nature of these needs, the DLM program, when properly operationalized, should provide utilities with reliable load relief in the near-term.

While all three products share a common goal, they are fundamentally different in the benefits they provide to the grid and should not be made to compete with each other. For example, DLM can include different resources such as DR, so for dispatchable DERs like BESS it’s not an apples-to-apples comparison.

Additionally, DLM terms are not sufficient to finance new BESS, and even if DLM was successful in attracting BESS resources, the business case to build them is not driven by DLM alone and is typically weighed against other value streams such as DRV. For example, while DLM bids can be substantial, the contract period is oftentimes too short for projects to be financeable strictly through DLM solicitations, but a VDER asset wishing to participate in DLM must forgo DRV and LSRV incentives associated with the value stack. This sets up a dynamic where DLM is in competition with DRV and LSRV and developers may elect DLM if the payment rate is sufficiently higher.

To address these shortcomings, the Commission must weigh its objectives for DLM and how they are similar or different from LSRV. The LSRV term was designed to support construction of new resources while DLM attracts existing or already in development BESS and provides higher compensation in exchange for greater dispatchability and control. the CEP recommend that Staff consider: (1) extending the DLM term in scenarios where immediate relief is still needed beyond the initial three-to-five-year

[20] Dynamic Load Management Program Agreement (Vintage Year 2024), p. 4

period; and (2) making these mechanisms stackable to further incentivize projects that have the ability to satisfy various needs.

Appendix: CEP LSRV Proposal

CEP Strawman Proposal for Calculation of DRV and LSRV values and Operationalization of LSRV Assets

In addition to responses to the questions posed by Department Staff, the CEP also offer this strawman proposal for how DRV and LSRV valuations could be determined and suggest better ways to operationalize LSRV capacity based on lessons learned. The CEP reiterate the importance of a locational price signal to act as a steering mechanism to attract DERs to areas where they are most needed and suggest revisions to the implementation of LSRV to ensure that it is better able to fulfil its original intention.

Overview of Proposed Methodology

This proposal contemplates MCOS studies conducted by substation area per the guidance of the August Order.[21] Potential LSRV areas would then be identified based on the amount of forecast incremental load and the suitability criteria for LSRV resource development enumerated below. The last evaluation step in determining an LSRV area would be to compare the MCOS values for a substation area to an LSRV reference price that would be required to spur development of DERs that can provide a distribution capacity resource. The CEP recommends the creation of a model by NYSERDA, as described further below, to account for the value streams that a VDER asset could realistically capture and determine what level of LSRV payments would be needed in addition to other payment streams to justify a project.[22] If designated LSRV areas exhibit MCOS values at or above the calculated reference price, then they will be more likely to attract development and be successful.

The CEP then recommend a mechanism to adjust the calculated MCOS values by substation area to account for value apportioned to LSRV projects. In each biennial DSIP cycle, the LSRV projects would be removed from the substation area load forecasts on a Price x Quantity basis.[23] Once the LSRV capacity has been removed, the MCOS for the substation area would be recalculated using the remaining forecast incremental load in excess of distribution system capacity to use in calculate an "adjusted" DRV. The adjusted DRV found using this method would then be adjusted for peak hours to arrive at a $/kWh value as is done presently.

---

[21] In response to Question 14, the CEP had recommended an adjustment to load forecasts, if necessary, that consisted of a scaling factor be applied to load forecasts at the substation area level to ensure that state policy is being fully considered and that any unexplainable gap between utility load forecasts and state sponsored studies is reduced.

[22] In the past, Department Staff have retained expert consultants to assist or facilitate proceedings of a highly technical nature such as Allocated Cost of Service Studies, Electric Vehicles, and Storage. The CEP envisions retention of a similar expert to assist with development of an energy storage cost model to calculate an LSRV reference price as described in greater detail herein.

[23] The removal of LSRV capacity areas would only apply to the distribution portion MCOS. This calculation should not consider Transmission.

The CEP assert that this process can be done transparently and algebraically if the distribution utilities provide workpapers documenting the substation area results of their MCOS studies.

LSRV Zonal Definitions and Threshold Criteria

LSRV areas should be designated after consideration of the likelihood that DERs can actually be developed within the LSRV area boundaries. At least some of the LSRV capacity that has gone unsubscribed to date is due to siting challenges in those locations. To ensure that LSRV area designations have a higher potential for success and to properly guide the market, the CEP propose that identified LSRV areas should meet the threshold criteria detailed in Table 3.

Table 3: LSRV Area Characteristics

Characteristic	Threshold Criteria
Incremental Load & Potential for System Constraints	Current load forecast scenarios show that load growth may exceed distribution system capacity in approximately four or more years
Load Growth Trends	Load growth scenarios show consistent and predictable load growth trends that suggest seasonal peak needs can be met by DERs; no known potential events/developments that would require a very large system upgrade (e.g., new mega-development)
Siting Availability	The LSRV area boundary is free of obvious constraints to DER development such as local moratoriums on development or known permitting issues that would preclude development of new DERs in the contemplated LSRV zone.
Deliverability	Interconnecting DER output is deliverable to the system
Resource Timelines	Selected projects are expected to come online four years from the initial posted price signal/tariff with contract terms of 10 years for capacity
Re-assessment Cycle	Load growth trends and contracted LSRV capacity should be evaluated to determine if the need still exists at each two-year DSIP cycle; LSRV zone to close to new entrants if needs are satisfied while new zones may also be opened or additional LSRV capacity designed in existing zones.
Transparency in Derivation Methods	LSRV calculated based on a reference price and systemwide DRV calculated based on substation area MCOS calculations after adjustment of incremental load forecasts to account for designated LSRV capacity. Workpapers should have sufficient detail so that DRV derivation could be independently replicated.

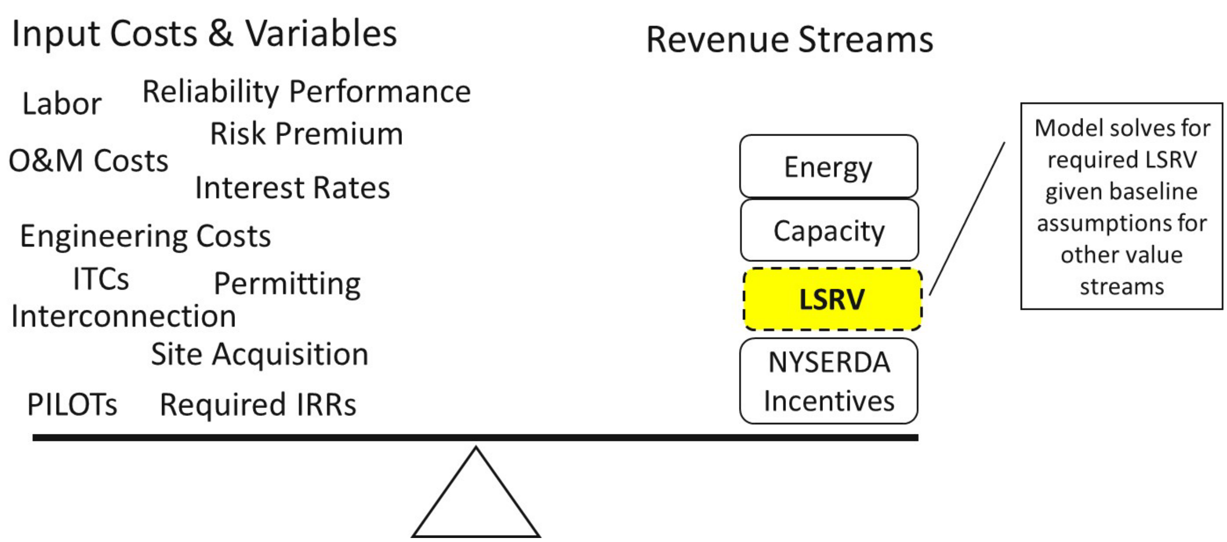
Proposed Method to Determine an LSRV Reference Price

The current method utilized by ConEd, O&R, and National Grid of using a scaling factor to gross up MCOS to derive DRV and LSRV does create price differentiation, but the selection of a scaling factor is somewhat arbitrary and does not ensure that the price signal will be sufficient to steer resource development to LSRV designated zones. The LSRV price signal needs to meet the dual objectives of attracting DERs that can consistently meet distribution system capacity needs while also ensuring that the cost to ratepayers for this capacity is less than or equal to a traditional utility capital project.
The CEP propose that the LSRV price level be calculated for different regions of New York via development of a levelized reference price determined in a model that considers all of the inputs and

costs of DER development. This model would assess the levelized revenues needed to justify investment in new DERs while also taking into account regional input cost differences in New York State and other factors such as interconnection costs which tend to be higher in areas where system constraints are more likely to occur. The CEP propose that NYSERDA manage the construction of this model. This approach has been employed in other highly technical proceedings and would ensure objectivity and transparency in the process. While LSRV is resource neutral, the CEP recommend that a proxy resource such as a four hour Battery Energy Storage System (BESS) be used in the development of the reference price, although resources other than a four hour BESS could also be evaluated for comparison.

The CEP would recommend that the model be updated with each DSIP cycle to assist in the identification of substation areas that meet the criteria for LSRV. Biennial updates would also ensure that trends in input costs and market prices are fully evaluated and updated. Substation areas would only qualify for an LSRV designation if the substation area specific MCOS values are greater than or equal to the calculated reference price.

At a high level, a non-exhaustive list of inputs and variables used to determine the LSRV reference price are shown in the graphic below.



The reference price model would rely upon baseline values for energy arbitrage, capacity, and prevailing NYSERDA storage incentives. Using the model input assumptions, the calculated difference between these value streams and the revenue required to support development of a four-hour BESS would determine the LSRV reference price. Since LSRV areas are more likely to occur in places with denser development patterns, the CEP expect that the interconnection costs, site acquisition costs, and the risk premiums for offering a reliability product would be higher than a typical BESS project and factored into the reference price analysis. NYSERDA incentives change periodically and if the model is updated biennially, these changes can be factored into the calculation of the LSRV reference price with a relatively short lag time.

Ultimately, the objective of the reference price is to set LSRV at a sufficient price level so that it will be able to serve its intended purpose in steering DER development to high value areas that require reliability resources. In the present time, the strongest steering mechanism for DER development, especially upstate, is low interconnection costs.

The CEP's method would provide a more rigorous structure to LSRV area identification and also better realize Staff's original desire to achieve "maximum flexibility in grouping together LSRV areas for compensation purposes."[24]

The modeling proposed above would also account for other changes to VDER that impact the economics of VDER projects. For example, in the past the Commission has considered shaping E-value to go from a flat 8760 rate to an on-peak, off-peak structure. These potential tariff changes will impact the viability of LSRV values since the cost of new entry is NET of the other components of the value stack.

The guiding force behind VDER was the goal of animating markets for DERs and viewing the distribution system as a platform for enabling an ecosystem of DERs providing benefits. The CEP observe that the current practices for valuation and administration of LSRV have been suboptimal and that market animation could accelerate with the changes proposed herein. At a minimum, LSRV payment rates must be sufficient to spur new development that is additional. The reference price proposal ensures that LSRV prices will be adequate to support development while also providing a mechanism for biennial adjustments. The biennial adjustments mean that any over or underpayments to DERs relative to the cost of new entry would be transitory as the reference price will self-correct for changes in BESS prices or markets with each update.

The consequences of underpaying DERs that provide distribution system capacity are actually more severe than a short period of overpayment. The load growth that is expected to occur in New York as electrification gathers momentum is large and the cost to ratepayers to meet load growth entirely with traditional capital upgrades would put tremendous pressure on rates. New York needs the market for clean energy DER solutions to work and a viable LSRV price signal coupled with improved operationalization is an important component in meeting that objective. The private sector is eager to meet these needs and development can be accelerated if identified barriers can be removed.

<u>Adjustment of DRV to Account for Value Paid to LSRV Resources</u>

The REV Track 2 Order adopted the policy direction that more granular rate design must be made available to engage customers efficiently in multi-sided DER markets.[25] Up to the present, MCOS values have been presented on a systemwide basis with varying methods to identify LSRV zones. The ConEd, O&R, and National Grid methods rely on a geographic percentage of the system that is designated as LSRV and then the payment rates for DRV and LSRV are determined via a "de-averaging" where value apportioned to the LSRV zones is removed from the DRV applicable to the rest of the system. One of the

[24] Staff Whitepaper 3/27/2023, p.43
[25] Case No. 14-M-0101, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework, 5/19/2016, p. 123

factors in the selection of the current approach was the lack of MCOS studies with greater spatial detail and therefore a high-level approach was considered a reasonable approximation for differentiating the value of DERs at that time.

The MCOS Order now requires calculation of marginal costs on an annual basis at substation area levels of granularity over 10 years. This added granularity allows for much greater precision in how DRV and LSRV can relate to each other in terms of apportionment of the MCOS value. The CEP propose a more targeted method of adjustment for DRV to more accurately reflect the value assigned to LSRV projects with biennial reviews to ensure that those projects are on track to materialize and the ability to remove them from the adjustment calculations in subsequent updates if they are not. The CEP proffer that the proposed method is more likely to right-size any reductions to DRV to account to LSRV resources in comparison to the current methods.

In contrast, the current method to determine DRV and LSRV is imprecise and relies upon the assumption that DERs will be constructed and receive full LSRV payments. If the expected DERs do not materialize, the effect is that value will be taken out of the DRV without the expected offsetting payments to LSRV resources. This has in fact been the case as described in the discussion of actual experience with LSRV capacity. The resulting outcome has been lost value for DERs compensated via the DRV which has been reduced by the de-averaging of DRV to account for phantom LSRV capacity. This phantom LSRV capacity can be attributable to projects not being constructed or capacity that fails to meet its performance obligations.

In terms of DER capacity ratings, non-dispatchable resources should have the option to participate in LSRV on a derated basis. There may be instances where a high-capacity factor DER, or a DER that is likely to be producing at distribution system peak hours, can deliver capacity to the system at high confidence intervals at a derated capacity level. This derating option should be available so that resources other than storage have the option to participate, if capable, in provision of LSRV capacity. The assignment of LSRV capacity to any derated resource should reflect the derated performance capability and not nameplate capacity.

Proposed Method for DRV Adjustment:

The CEP propose the method described below to adjust DRV to reflect the value apportioned to LSRV capacity. The method relies upon having marginal costs presented by substation area for each year in the 10-year study period as outlined in the MCOS Order.[26]

Summary of Steps in Proposed CEP Adjustment Method for DRV:

1) Conduct the substation area MCOS Study for each year in the 10-year period per the guidance from the Order
2) If the MCOS Study identifies an emerging need for capacity resources to meet peak loads, assess whether the substation area is suitable for LSRV projects per the criteria enumerated above.

[26] Cite to MCOS Order, p. 46

3) If the substation area meets the criteria for an LSRV project, select a quantity of capacity to assign to LSRV resources to meet emerging system needs in Year 4 or later.
4) Subtract the capacity assigned to LSRV resources from the peak load forecast used in Step 1 to recalculate the substation area MCOS with the quantity of LSRV resources removed from each applicable year.
    a. The removal of LSRV capacity should only applicable to the distribution portion of the MCOS and not the transmission portion which should remain unchanged.
5) Utilize the MCOS Adjusted for LSRV for the substation area to calculate the systemwide DRV.

The table below provides an illustrative example of this process for a hypothetical substation area.

	Illustrative MCOS Calculation for Substation Area Designated for LSRV Project										
Calculation Step	**Years**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
Calculate MCOS per Substation Area in Accordance w/ Aug'24 Order	Substation Area MCOS										
	Incremental Peak Load > Dist System Capacity (MW)	0	1	1	4	8	12	15	16	17	18
	Marginal Unit Rate ($/MW)	$0	$0	$350	$365	$387	$410	$435	$461	$488	$518
If Substation Area Meets Criteria for LSRV, Determine Capacity to be Made Available for LSRV Projects	Capacity Assigned to LSRV Projects										
	LSRV Capacity (MW):				5	10	10	10	10	10	10
	Payment Rate ($/MW-yr):				$330	$330	$330	$330	$330	$330	$330
Recalculate MCOS per Substation Area with LSRV Capacity Removed from Distribution Value to Determine DRV	Re-Calculate MCOS to Determine DRV Value										
	Remaining Incremental Peak Load > Dist System Capacity (MW)	0	1	1	0	0	2	5	6	7	8
	Marginal Unit Rate ($/MW)	$0	$0	$350	$0	$0	$369	$391	$415	$440	$466

The table shows a substation with a pattern of emerging steady load growth. Based on the load growth between the present and year 5, the distribution utility determines that 10 MW of LSRV projects would be sufficient to alleviate near term capacity constraints. Although there is additional load growth in the further out years, the two-year refresh cycle of MCOS Studies in the DSIPs will allow for a better evaluation of the out years when newer data becomes available in subsequent studies. The table shows how the LSRV capacity can be removed from the distribution portion of the substation area MCOS so that an adjusted MCOS can be conducted on the remaining load for the purpose of calculating the systemwide DRV. In essence, this approach reverses the de-averaging order of operations where LSRV capacity and project costs are removed from the substation area MCOS prior to the calculation of the system-wide value.

The table also shows a hypothetical LSRV resource with a reference price that is below the substation area MCOS. In this scenario, the difference between the cost of LSRV resource and the substation area MCOS would accrue as a benefit to ratepayers and also flow into the calculation of the adjusted DRV.

If the MCOS Studies are updated on a biennial cycle, the LSRV capacity assigned to suitable substations can be adjusted upward to accommodate new projects if load growth continues. Conversely, the capacity assigned to LSRV resources could be adjusted downward if it appears that those resources are unlikely to materialize based on the active interconnection queue and feedback from developers. Developer experience has shown that this is a possibility when despite their best efforts, building projects in LSRV areas may become stymied by local permitting and zoning problems, local moratoriums, or other siting challenges that can make capacity development inaccessible in a specific area. The two-year refresh cycle should dynamically keep LSRV designations and capacity requirements aligned with system needs and ensure that the adjustment to DRV is right-sized to reflect actual system conditions and DER development.

Accurate workpapers detailing study results by substation area are critical for the CEP's proposed method to be viable. The CEP urge the Commission to require that the load forecasts by substation area be included in compliance filings and that the adjustment to DRV for LSRV capacity be available for inspection in live spreadsheet workpapers. The workpapers should include sufficient detail so that the algebraic formulas used to derive the values can be traced out and replicated. This transparency is critical for participants in the market to understand the process and the derivation of DRV and LSRV price signals. In addition to the price signals, reporting or information in workpapers regarding LSRV capacity uptake is important to show the market what capacity remains available and provide transparency for unsubscribed LSRV capacity that may be reallocated back to DRV if the market cannot produce DERs for whatever reason.

Summary of LSRV Capacity Management to Date

The LSRV is supposed to act as a price signal that serves as a steering mechanism to direct DER investment to areas where it has the most benefit. The experience with VDER over the last six years shows that changes are necessary to ensure that LSRV actually works as an effective steering mechanism. In practice, development of DERs in LSRV areas has been hampered by a combination of insufficient price signals and local difficulties in permitting and constructing DERs in LSRV zones.
The table below provides a summary of available LSRV capacity at the beginning of VDER in approximately November 2017 and how much remains unsubscribed presently.[27]

	LSRV Available Capacity by Utility Service Area (MW)				
VDER Statement Month	ConEd	O&R	National Grid	NYSEG	RGE
Nov-2017	87.8	24	102.5	7.94	4.62
Nov-2024	6.81	16.1	52.53	5.71	4.62
Difference	80.99	7.9	49.97	2.23	0

[27] Data obtained from VDER Statements for the months indicated by utility

In RG&E, no VDER projects have been developed which may be due to the relatively low LSRV payment rates of $47.96 and $9.47/kW-year, respectively for the two available LSRV zones. In NYSEG, there has been some development activity in two out of four LSRV areas, but LSRV prices also remain low ranging from $21.82 to $56.26/kW-year.

In National Grid, there are 53 uniquely identified LSRV areas and 19 of these had their capacity fully subscribed. Available LSRV capacity by zone in National Grid ranges from 13.1 MW to 0.1 MW.

In Orange & Rockland (O&R), two out of five LSRV areas have been fully subscribed with minimal development in the remaining three. O&R's LSRV payment rate is $39.61/kW-year.

As described above, it is important that the LSRV price signal be set at a level to steer development and also produce additionality in DER development. In the utilities outside of ConEd, the LSRV price signal has been weak and generally insufficient to spur development of capacity resources on its own.

ConEd's LSRV payment rate is $141/kW-yr, and there are 15 identified LSRV areas that initially totaled to 87.8 MW of capacity. Since 2017, 58.8 MW of this LSRV capacity has been reallocated to NWAs, and approximately 24 MW of the reallocated capacity has been successfully converted to operational NWAs.

Specifically, in October 2018, ConEd reported that it was moving forward with NWAs at Plymouth Sub-transmission, Water St. Sub-transmission and W 42nd St. No. 1 Area Station and would no longer be offering LSRV values in these areas.[28] A collective 44.4 MW of capacity was removed from the Plymouth and Water St. load areas and replaced with a 14 MW NWA.[29] 6.5 MW were removed from the W 42nd St. No. 1 Area Station for a NWA portfolio that was ultimately unable to be assembled due to lack of adequate, cost-effective load reduction from RFP responses.[30] This capacity was added back to ConEd's VDER statement in March 2021.[31] LSRV capacity associated with Newtown Sub-transmission was removed in 2019 and replaced with approximately 10 MW of contracted energy storage.[32] While some of the removed LSRV capacity was successfully converted to NWAs, mismatched timelines[33] and persisting phantom capacity issues suggest that the JU's proposal to replace LSRV with NWAs is not a suitable solution.

Additionally, the original "de-averaging" formula operated under the assumption that 19 percent of ConEd's service territory qualified as an LSRV area.[34] The average system-wide MCOS of $226/kW-yr was reduced to $199/kW-yr to account for the additional value to be allocated to LSRV resources. The result has been a reduction of $27/kW-yr in MCOS value allocated to DRV based on a presumption of 87.8 MW

---

[28] ConEd Statement of Value of Distributed Energy Resources Value Stack Credits, Statement No. 12, 10/1/2018
[29] Case No. 22-E-0064, NWS Quarterly Expenditures and Semi-Annual Program Report, 11/29/2023, Appendix A: NWS Portfolio History to Date, pp. 12-17
[30] Id., p. 14
[31] ConEd Statement of Value of Distributed Energy Resources Value Stack Credits, Statement No. 42, 3/1/2021
[32] Case No. 22-E-0064, NWS Quarterly Expenditures and Semi-Annual Program Report, 11/29/2023, p. 8
[33] See NWA table in response to Question 8
[34] Case No. 15-E-0751, ConEd Implementation Proposal for Value of Distributed Energy Resources Framework, 5/1/2017, p. 3

of LSRV capacity development.[35] In practice, the data from VDER statements and NWA projects suggests that of the original projection of 87.8 MW of capacity, approximately 23 MW has been reportedly developed as LSRV resources and approximately 24 MW as NWA projects. This mismatch in projections versus capacity actually developed reinforces the need for a more precise adjustment of DRV to account for payments to LSRV resources as well as a more frequent update to DRV values and identification of LSRV areas. While this discussion has focused on ConEd, the same issue is present to varying degrees in the other distribution utilities detailed in the table above as the unsubscribed LSRV capacity was factored into the deaveraging of LSRV.

<u>LSRV Can be Improved with Better Operationalization</u>

The utility preference for control of LSRV assets wasn't fully considered in the original design of the VDER program. The CEP contend that utility concerns regarding the reliability of LSRV resources can be addressed through better operationalization. The CEP provides the following recommendations for improved operationalization below:

1) Consideration of Siting Issues
    a. As described above in the LSRV threshold criteria, prior to designating an area as being qualified for LSRV the surrounding area should be evaluated to determine if there are any known or obvious barriers to DER development such as local moratoriums on DER development other severe permitting or siting limitations.
2) Maintenance of Accurate Hosting Capacity Maps
    a. Review of hosting capacity maps is an important part of the project development process and has the ability to drive investments to key locations when property maintained. The CEP recommend annual updates of this resource.
3) Improved Dispatch Management Informed by NWA and DLM Experience
    a. In the elapsed time since the beginning of VDER, NWAs and DLM programs have provided the joint utilities with valuable experience that can be adapted to LSRV. Specifically, learnings from DLM can be applied to LSRV which could operate akin to a 10-year DLM with more rigorous dispatching plans that are better suited to actual distribution system needs.
    b. Presently, LSRV programs identify a number of calls that must be made in a given year, but there does not appear to be a solidified strategy for determining when LSRV call events should occur. As a result, LSRV is likely not providing its full potential relief to the system. The VDER tariff should be updated to include specific criteria for LSRV events including expected dispatch duration. This clarity would in turn help provide developers with much needed certainty regarding modeling DER project parameters and bankability.
4) Clarification of Payment Criteria
    a. There is currently a range of hours that an LSRV call may last, but it is ambiguous if assets are paid based on the number of hours of response or the call itself.

[35] If 87.8 MW of LSRV capacity represented 19% of the system weighted marginal cost, then the total systemwide marginal load could be estimated as 87.8 MW ÷ 19% = 462 MW.

    b. Clarification of parameters used to measure dispatch performance and identification of potential derates in capacity or payment rates for poor event performance should be clearly specified in the LSRV tariff.

5) Improved Measurement of LSRV Resource Reliability
    a. The capacity value assigned to LSRV resources should be updated with each biennial cycle to ensure that LSRV resources are delivering their expected reliability benefits during dispatch events. This is needed for LSRV resources to effectively address long-term load growth expectations.
    b. This modification would help provide assurance that selected projects will serve their intended purpose of avoiding or deferring traditional solutions that would otherwise be needed in that five-to-ten-year period and if LSRV assets are not performing, their LSRV capacity could be opened up to new assets in subsequent biennial MCOS update cycles.
6) LSRV Queue Management
    a. The LSRV queue should be managed in a way that achieves the following dual purposes: that developers know if their project will secure an LSRV capacity assignment, and; that projects with LSRV capacity assignments not meeting development milestones could have their capacity reassigned to other projects that are more likely to come to fruition.
    b. Accurate and timely queue management is needed to ensure that resources can be assessed in line with the biennial MCOS reviews so that DSIPs can report on the state of LSRV market including the amount of LSRV capacity that has been claimed and any capacity that has been reassigned or removed for other reasons. Unused LSRV capacity, including projects that withdraw from the interconnection queue, should be reallocated back into the DRV.
    c. Derated non-dispatchable resources should be awarded LSRV capacity that is aligned with their derated performance capability instead of nameplate or any other value that may remove more LSRV capacity from the market than the resource is able to deliver.
7) Minimum Filing Requirements that Include Transparent Workpapers
    a. As described above, the MCOS workpapers developed in accordance with the August Commission Order should be transparent and replicable by stakeholders. This will increase understanding of the program and development hot spots for developers and also for the financial community to better understand LSRV asset performance obligations and payment structures.