Electric Benefit Cost Analysis Handbook

Version 4.0
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VERSION HISTORY

Version	File Name	Last Updated	Document Owner	Updates since Previous Version
V1.0	Con Edison BCA Handbook - v1.0	06/30/16	Con Edison	First Issue
V1.1	Con Edison BCA Handbook – v1.1	8/19/16	Con Edison	Correction to Equation 4-3; Equation 4-7 Table A-2
V1.2	Con Edison BCA Handbook – v2.0	7/31/18	Con Edison	Second Issue
V1.3	Con Edison Electric BCA Handbook – v3.0	7/31/20	Con Edison	Third Issue
V1.4	Con Edison Electric BCA Handbook – v4.0	6/30/23	Con Edison	Fourth Issue

BACKGROUND

New York's Joint Utilities[1] collaboratively developed a Standard Benefit Cost Analysis (BCA) Handbook Template 1.0 in 2016 and have collaboratively worked to develop a revised 2018 Standard BCA Handbook Template 2.0 which reflects revisions to the 2016 filing. The purpose of the BCA Handbook Template 2.0 is to provide interested parties a consistent and transparent methodology to calculate the benefits and costs of potential projects and investments. The 2018 Standard BCA Template 2.0 serves as the common basis for each utility's individual BCA Handbook.

The Handbooks present applicable BCA methodologies and describe how to calculate individual benefits and costs as well as how to apply the necessary cost-effectiveness tests identified in the *Order Establishing the Benefit Cost Analysis Framework*).[2] The BCA Handbooks also present general BCA considerations and notable issues regarding data collection required for project and investment benefits assessments. Definitions and equations for each benefit and cost are provided along with key parameters and sources. Where applicable, Con Edison has customized the handbook to account for utility specific assumptions and information.

[1] The Joint Utilities are Consolidated Edison Company of New York, Inc., Orange and Rockland Utilities, Inc., Central Hudson Gas & Electric Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, New York State Electric and Gas Corporation, and Rochester Gas & Electric Corporation.

[2] Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Establishing the Benefit Cost Analysis Framework (issued January 21, 2016) (BCA Order).

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I. ACRONYMS AND ABBREVIATIONS

Acronyms and abbreviations are used extensively throughout the BCA Handbook and are presented here for ease of reference.

AC	Alternating Current
AGCC	Avoided Generation Capacity Costs
BCA	Benefit-Cost Analysis
BCA Framework	The benefit-cost framework structure presented initially in the “Staff White Paper on Benefit-Cost Analysis” and finalized in the *BCA Order*.
BCA Order	Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Establishing the Benefit-Cost Analysis Framework (issued January 21, 2016).
C&I	Commercial and Industrial
CAIDI	Customer Average Interruption Duration Index
CARIS	Congestion Assessment and Resource Integration Study
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
DC	Direct Current
DER	Distributed Energy Resources
DR	Demand Response
DSIP	Distributed System Implementation Plan
DSIP Guidance Order	Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Adopting Distributed System Implementation Plan Guidance (issued April 20, 2016)
DSP	Distributed System Platform
EPA	Environmental Protection Agency
EE	Energy Efficiency
GHG	Greenhouse Gas
ICAP	Installed Capacity
JU	Joint Utilities (Consolidated Edison Company of New York, Inc., Orange and Rockland Utilities, Inc., Central Hudson Gas & Electric Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, New York State Electric and Gas Corporation, and Rochester Gas & Electric Corporation)
kV	Kilovolt
LBMP	Locational Based Marginal Prices
LCR	Locational Capacity Requirements
LHV	Lower Hudson Valley
LI	Long Island
MW	Megawatt
MWh	Megawatt Hour
NEM	Net Energy Metering
NPV	Net Present Value
NO_x	Nitrogen Oxides
NWA	Non-Wires Alternatives
NYC	New York City
NYCA	New York Control Area
NYISO	New York Independent System Operator
NYPSC	New York Public Service Commission

NYSERDA	New York State Energy Research and Development Authority
O&M	Operations and Maintenance
PV	Photovoltaic
REV	Reforming the Energy Vision
REV Proceeding	Case 14-M-0101 – *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*
RGGI	Regional Greenhouse Gas Initiative
RIM	Rate Impact Measure
RMM	Regulation Movement Multiplier
ROS	Rest of State
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAM	System Advisor Model (National Renewable Energy Laboratory)
SCC	Social Cost of Carbon
SCT	Societal Cost Test
SENY	Southeast New York (Ancillary Services Pricing Region)
SO_2	Sulfur Dioxide
T&D	Transmission and Distribution
UCT	Utility Cost Test

1.1 Introduction

The New York Public Service Commission (NYPSC or Commission) directed the Joint Utilities (JU) to develop and file Benefit-Cost Analysis (BCA) Handbooks by June 30, 2016, as a requirement of the *Order Establishing the Benefit-Cost Analysis Framework* (BCA Order).[3] The BCA Framework included in Appendix C of the *BCA Order* is incorporated into the BCA Handbooks.

The purpose of the BCA Handbook is to provide a common methodology for calculating benefits and costs of projects and investments. The BCA Order requires that a benefit-cost analysis be applied to the following four categories of utility expenditure:[4]

- Investments in distributed system platform (DSP) capabilities
- Procurement of distributed energy resources (DER) through competitive selection[5]
- Procurement of DER through tariffs[6]
- Energy efficiency programs

The BCA Handbook provides methods and assumptions that may be used to inform BCA for each of these four types of expenditure.

The *BCA Order* also includes key principles for the BCA Framework that are reflected in this 2023 BCA Handbook. Specifically, the Commission determined that the BCA Framework should be based on transparent assumptions; methodologies and lists benefits and costs including those that are localized and more granular:[7]

- Avoid combining or conflating different benefits and costs.
- Assess portfolios rather than individual measures or investments (allowing for consideration of potential synergies and economies among measures).
- Address the full lifetime of the investment while reflecting sensitivities on key assumptions.
- Compare benefits and costs to traditional alternatives instead of valuing them in isolation.

1.2 Application of the BCA Handbook

The BCA Handbook provides a common methodology to be applied across investment projects and portfolios. The current version of the BCA Handbook is meant to inform investments in DSP capabilities, the procurement of DERs through tariffs, the procurement of DERs through competitive solicitations (i.e. non-wire alternatives) and the procurement of energy efficiency resources. Common input assumptions and sources that are applicable on a statewide basis (e.g., information publicly provided by the New York Independent System Operator (NYISO) or by Department of Public Service (DPS) Staff as required in the BCA Order) and utility-specific inputs (e.g., marginal costs) that may be commonly applicable to a variety of project-specific BCAs are provided within. Individual BCAs for specific projects or portfolios are likely to require additional, project-specific information and inputs.

[3] REV Proceeding, BCA Order.
[4] REV Proceeding, BCA Order, pp. 1-2.
[5] These are also described as non-wires solutions (NWS).
[6] These may include, for example, demand response tariffs or successor tariffs to net energy metering (NEM).
[7] REV Proceeding, BCA Order, pg. 2.

Table 1-1 lists the statewide values and respective sources to be used for BCA and referenced in this Handbook. Source references are included in the footnotes below.

Table 1-1. New York Assumptions

New York Assumptions	Source
Energy and Demand Forecast	NYISO: Load & Capacity Data[8]
Avoided Generation Capacity Cost (AGCC)	DPS Staff: ICAP Spreadsheet Model[9]
Locational Based Marginal Prices (LBMP)	NYISO: Congestion Assessment and Resource Integration Study Phase 2 (CARIS Phase 2)[10]
Historical Ancillary Service Costs	NYISO: Markets & Operations Reports[11]
Wholesale Energy Market Price Impacts	DPS Staff: To be provided[12]
Allowance Prices (SO_2, and NO_X)	NYISO: CARIS Phase 2[13]

Utility-specific assumptions include data embedded in various utility published documents such as rate cases. Table 1-2 lists the suggested utility-specific assumptions for the BCA Handbook.

Table 1-2. Utility-Specific Assumptions

Utility-Specific Assumptions	Source
Weighted Average Cost of Capital	CECONY Electric Case 22-E-0064 *(twelve months ending December 31, 2025)*
Losses	Con Edison's 2007 Electric System Losses Study
Marginal Cost of Service	Consolidated Edison 2016 Rate Case Filing DAC-3 Schedule 1
Reliability Statistics	DPS: Electric Service Reliability Reports[14]

The New York general and utility-specific assumptions that are included in the 2023 version of the BCA Handbook (as listed in Table 1-1 and Table 1-2) are typically values by zone or utility system averages. The BCA methodology underlying the BCA Handbook is technology-agnostic and should be broadly applicable to all anticipated project and portfolio types with some adjustments as necessary. BCA development will require the standard inputs provided in the BCA Handbook as well as project-specific information that captures locational and temporal aspects of the investment under analysis.

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[8] The 2023 Load & Capacity Data report is available in the NYISO Load & Capacity Data Report ("Gold Book") folder in the document library at: https://www.nyiso.com/library.
[9] The ICAP Spreadsheet Model is found under Case 14-M-0101 at the Commission's website: http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-M-0101&submit=Search. At the time of this publication, the most recent model was filed on October 3, 2022.
[10] The finalized annual and hourly zonal LBMPs from CARIS Phase 2 are available on the NYISO website in the CARIS Study Outputs folder within the Economic Planning Studies folder: https://www.nyiso.com/en/cspp.
[11] Historical ancillary service costs are available on the NYISO website at: https://www.nyiso.com/custom-reports. The values to apply are described in Section 4.1.5.
[12] DPS Staff will perform the modeling and file the results with the Secretary to the Commission on or before July 1 of each year.
[13] The allowance price assumptions for CARIS Phase 2 studies will be available on the NYISO website in the Input Assumptions folder within Economic Planning Studies at: https://www.nyiso.com/en/cspp. At the time of this publication, the most recent filing was posted on November 30, 2018.
[14] The latest Annual Electric Service Reliability Report is available at: https://dps.ny.gov/electric-service-reliability-report-2021.

1.3 BCA Handbook Version

This 2023 BCA Handbook v4.0 provides techniques for quantifying the benefits and costs identified in the BCA Order. Interim revisions will be limited to material changes to input assumptions and/or new guidance or orders.

1.4 Structure of the Handbook

The remaining sections of the Handbook explain the methodology and assumptions to be applied under the BCA Framework:

> **Section 2. General Methodological Considerations** describes key issues and challenges to be considered when developing project-specific BCA models and tools based on this BCA Handbook.
>
> **Section 3. Relevant Cost-Effectiveness Tests** defines each cost-effectiveness test included in the BCA Framework. These include the Societal Cost Test (SCT), the Utility Cost Test (UCT), and the Rate Impact Measure (RIM). The BCA Order specifies the SCT as the primary measure of cost-effectiveness.
>
> **Section 4. Benefits and Costs Methodology** provides detailed definitions, calculation methods, and general considerations for each benefit and cost.
>
> **Section 5. Characterization of DER profiles** discusses which benefits and costs are likely to apply to different types of DER and provides examples for a sample selection of DER.
>
> **Appendix A. Utility-Specific Assumptions** includes value assumptions to be applied to the quantifiable energy and non-energy impacts of projects and portfolios.

2. GENERAL METHODOLOGICAL CONSIDERATIONS

This section describes key issues and challenges that must be considered when developing project- or portfolio-specific BCAs. These considerations are incorporated into the benefit and cost calculation methods presented in Section 4.

2.1 Avoiding Double Counting

A BCA must be designed to avoid double counting of benefits and costs. Doubling-counting can be avoided by (1) careful tracking of the value streams resulting from multiple investment elements in a project, program, or portfolio and (2) clearly defining and differentiating between the benefits and costs included in the analysis.

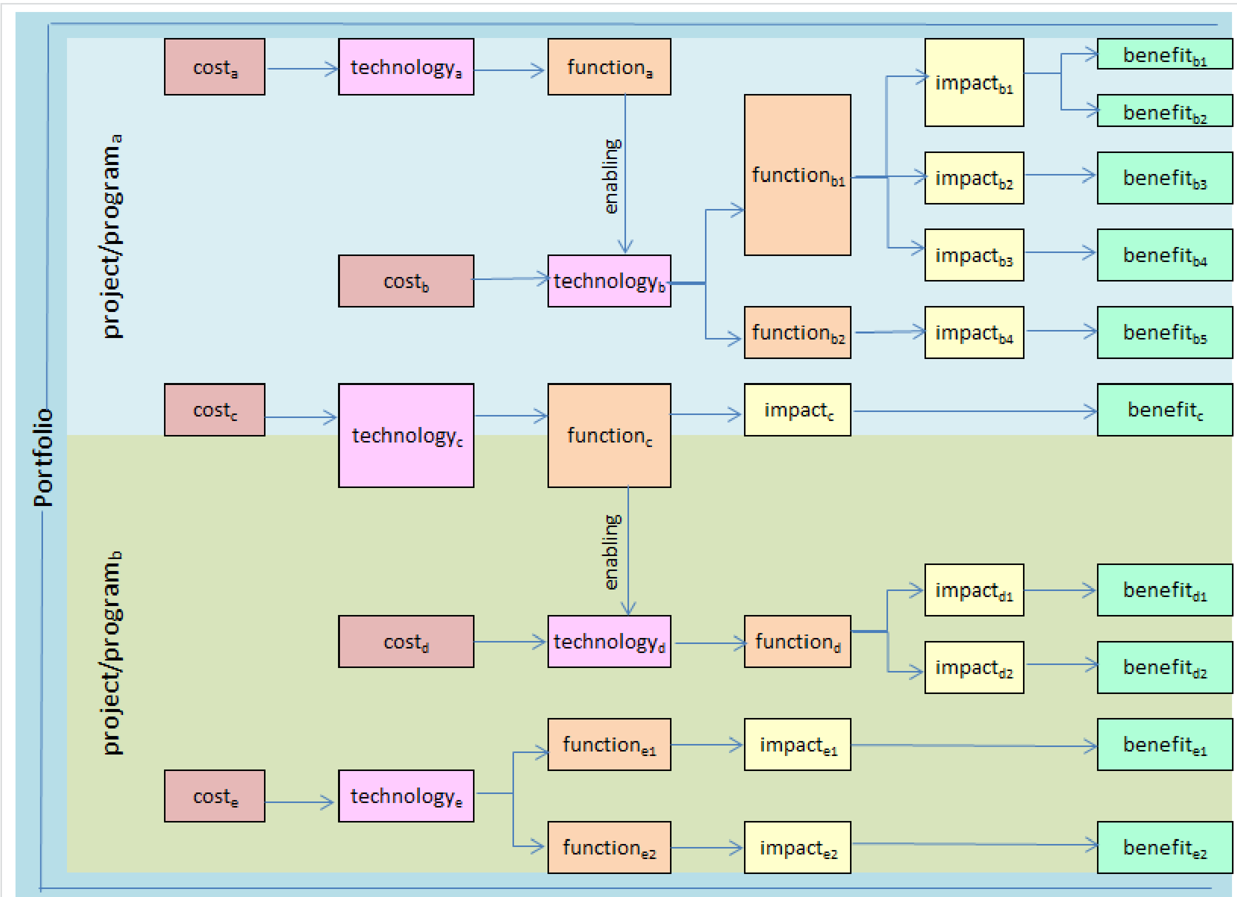
Sections 2.1.1 and 2.1.2 discuss these considerations in more detail.

2.1.1 Accounting of Benefits and Costs Across Multiple Value Streams

The BCA Handbook provides a methodology for calculating the benefits and costs resulting from utility investments as portfolios of projects and programs or as individual projects or programs. A project or program will typically involve multiple technologies, each associated with specific costs. Each technology provides one or more functions that result in quantified impacts and are valued as monetized benefits.

Figure 2-1 is an illustrative example of value streams that may be associated with a portfolio of projects or programs.

Figure 2-1. Illustrative Example of Value Streams that May be Associated with a Portfolio of Projects or Programs



Source: National Grid

Investments may be made in technologies that do not result in direct benefits but instead function to enable or facilitate the realization of benefits from additional measures or technologies (e.g., technology$_b$ in Figure 2-1). Some technologies may both enable or enhance the benefits of other technologies and result in direct benefits though a parallel function (e.g., technology$_c$ in Figure 2-1). It is important not to double-count benefits resulting from multiple measures or technologies functioning together to achieve an impact. Determination of which impacts and benefits are derived from which investment elements will often depend on how and/or in what order the elements are implemented.

Benefits and costs should also be allocated properly across different projects within a portfolio. This may present challenges especially in the case of enabling technologies. For example, the investment in technology$_c$ in Figure 2-1 is included as part of project/program$_a$. Some direct benefits from this technology are realized for project/program$_a$, however technology$_c$ also enables technology$_d$ that is included as part of project/program$_b$. In this example, the costs of technology$_c$ and the directly resulting benefit should be accounted for in project/program$_a$, and the cost for technology$_d$ and the resulting incremental benefits should be accounted for in project/program$_b$.

Enabling technologies such as an advanced distribution management system or a communications infrastructure are often crucial in achieving the impact and benefits of grid modernization projects. These infrastructure investments may be necessary for the implementation of other technologies, projects, or programs, and in some cases the same investments could also enable a given asset to achieve additional benefits beyond what that asset may have been able to achieve on its own. Over time, investments made as part of previous projects or portfolios may also enable or enhance new projects. The BCA Order states that utility BCA shall consider incremental T&D costs “to the extent that the characteristics of a project cause additional costs to be incurred.”[15]

Multiple technologies may result in impacts that produce the same benefits. For example, there are many ways in which distribution grid modernization investments could affect the frequency and duration of sustained outages. Advanced meters equipped with an outage notification feature, an outage management system, automated distribution feeder switches or reclosers, and remote fault indicators are some examples of technologies that could all reduce the frequency or duration of outages on a utility’s distribution network and result in Avoided Outage Cost or Avoided Restoration Cost benefits.

The utility BCA must also address the non-linear nature of grid and DER project benefits. For example, the impact on Avoided Distribution Capacity Infrastructure of an energy storage project may be capped based on the interconnected load on the given feeder. For example, if there is 1 MW of potentially deferrable capacity on a feeder with a new battery storage system, installation of a 5-MW storage unit will not result in a full 5 MW-worth of capacity deferral credit for that feeder. As another example, the incremental improvement in reliability indices may diminish as more automated switching projects are in place.

2.1.2 Benefit Definitions and Differentiation

A key consideration when performing a BCA is to avoid double counting of benefits and costs by appropriately defining each benefit and cost.

As discussed in Section 3 the BCA Order identified 16 benefits to be included in the cost-effectiveness tests. The calculation methodology for each of these benefits is provided in Section 4. Two bulk system benefits, Avoided Generation Capacity Costs (AGCC) and Avoided LBMP, result from system coincident peak demand reduction and energy reduction impacts respectively, with avoided cost values derived from multiple components. These impacts and embedded component values included in the AGCC and Avoided LBMP benefits should not be confused with other benefits identified in the *BCA Order* that must be calculated separately.

Sections 2.1.2.1 and 2.1.2.2 below define the avoided transmission and distribution loss impacts resulting from energy and demand reductions that should be included in the calculations of the AGCC and Avoided LBMP and differentiate them from the impacts that should be counted as separate Avoided Transmission Losses and Avoided Distribution Losses benefits. Sections 2.1.2.1 and 2.1.2.2 also provide differentiation between the transmission capacity values embedded as components of the AGCC and Avoided LBMP values, as well as differentiation between the CO_2, SO_2, and NO_x values embedded in Avoided LBMP values and those values that must be applied separately in the Net Avoided CO_2 and Net Avoided SO_2, and NO_x benefits calculations.

[15] REV Proceeding, BCA Order, Appendix C, p. 18.

Table 2-1 provides a list of potentially overlapping AGCC and Avoided LBMP benefits.

Table 2-1. Benefits with Potential Overlaps

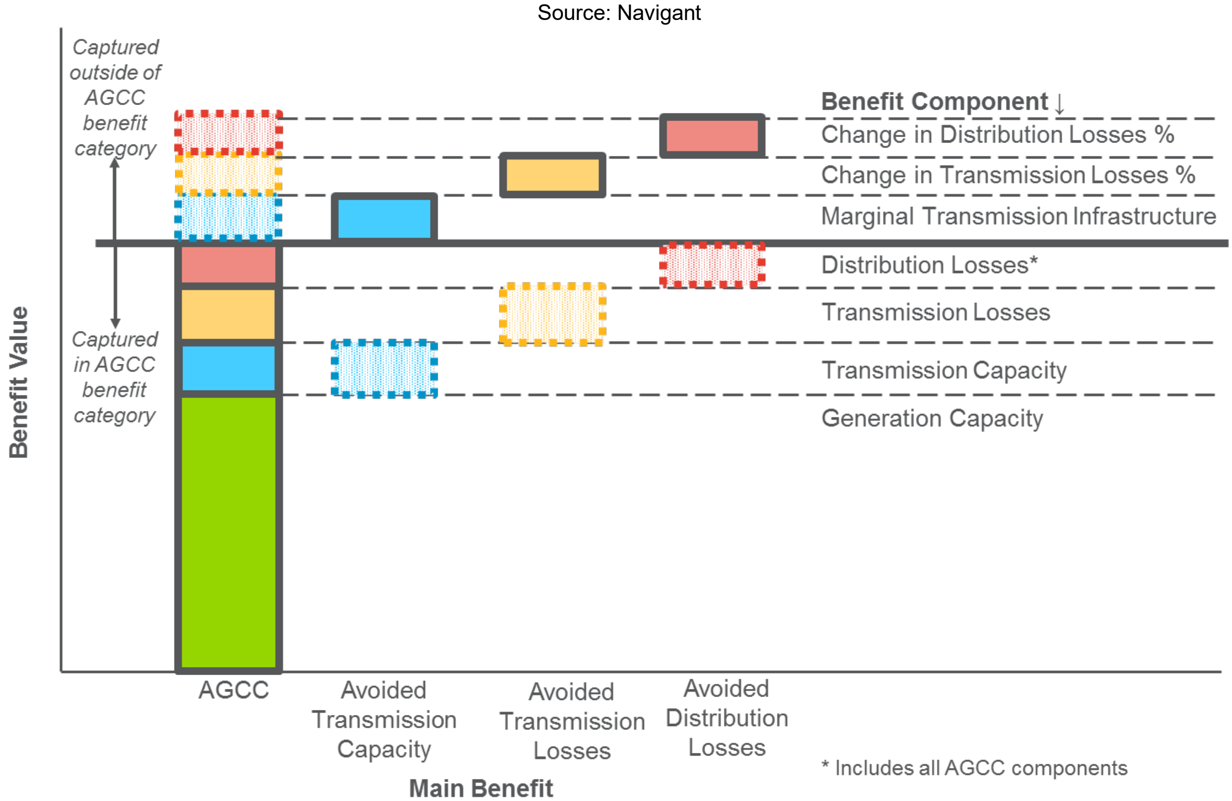
Main Benefits	Potentially Overlapping Benefits
Avoided Generation Capacity Costs	• Avoided Transmission Capacity • Avoided Transmission Losses • Avoided Distribution Losses
Avoided LBMP	• Net Avoided CO_2 • Net Avoided SO_2 and NO_x • Avoided Transmission Capacity • Avoided Transmission Losses • Avoided Distribution Losses

2.1.2.1 Benefits Overlapping with Avoided Generation Capacity Costs

Figure 2-2 graphically illustrates potential overlaps of benefits pertaining to the AGCC.

Figure 2-2. Benefits Potentially Overlapping with Avoided Generation Capacity Costs (Illustrative)

Source: Navigant



In this stacked column chart, the boxes with solid borders represent impacts and embedded values included in the calculation of the main benefit, while boxes with dotted borders represent impacts not contained in the main benefit but reflected in the calculation of a separate benefit. The benefit shown above, Avoided Generation Capacity Costs, includes multiple components that are captured in the AGCC value. These include – ICAP including reserve margin, transmission capacity, and transmission losses.[16] Additionally, a project location on the system can affect distribution losses and the calculation of AGCC.[17] The AGCC calculation accounts for these distribution losses.

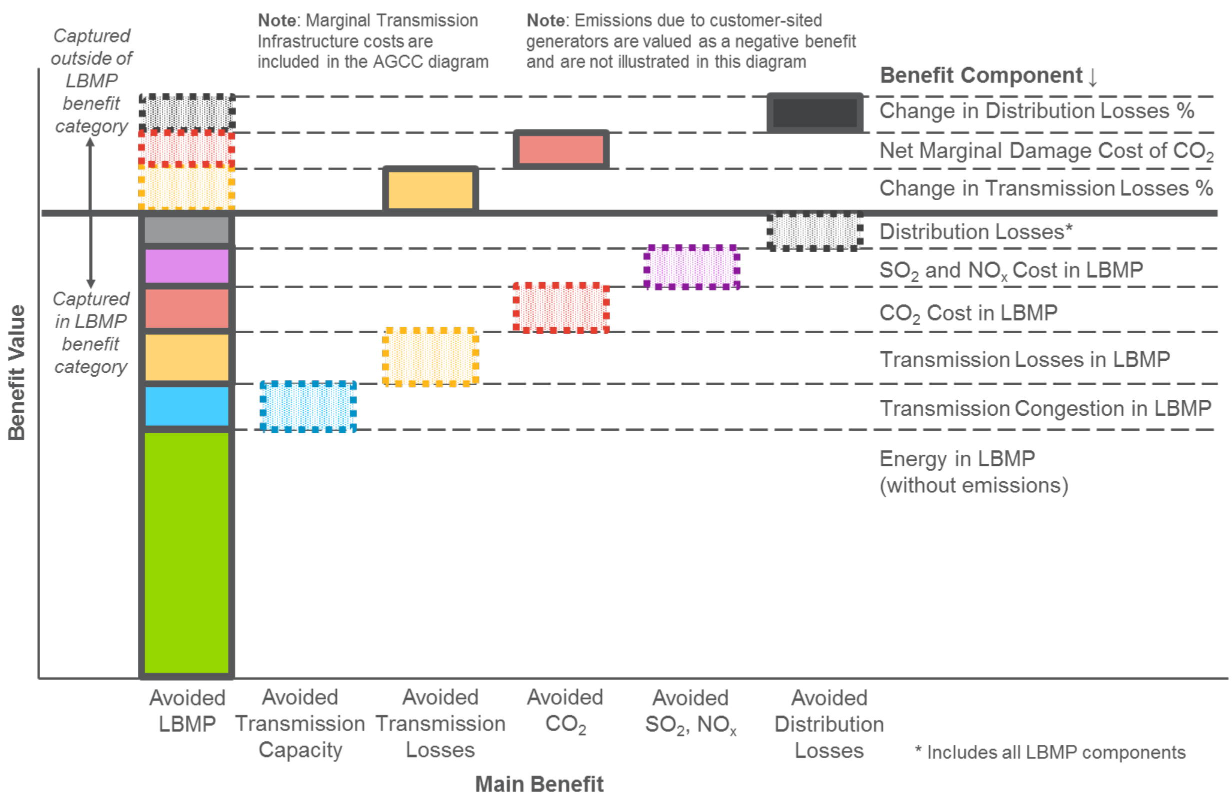
If a project changes the electrical topology and therefore the transmission loss percent, the incremental changes in transmission losses would be allocated to the Avoided Transmission Losses benefit. Similarly, any incremental changes to distribution loss percent as a result of the project would be included in the Avoided Distribution Losses benefit. These benefits are calculated separately from the AGCC benefit.

2.1.1.1 Benefits Overlapping with Avoided LBMP

Figure 2-3 graphically illustrates potential overlaps of benefits pertaining to Avoided LBMP.

Figure 2-3. Benefits Potentially Overlapping with Avoided LBMP Benefit (Illustrative)

Source: Navigant



In this stacked column chart, the boxes with solid borders represent impacts and embedded values included in the calculation of the main benefit, while boxes with dotted borders represent impacts excluded from the main benefit but included in calculation of a separate benefit. As seen in the figure, the stacked solid boxes in the Avoided LBMP benefit include costs for factors beyond just the energy cost per

[16] The AGCC includes a portion of avoided transmission capacity infrastructure costs as zonal differences in the ICAP clearing price.
[17] For example, an impact on the secondary distribution system compared to the primary system will have a higher impact on the AGCC due to higher losses.

megawatt-hour (MWh) of the electricity traded in the wholesale energy market. The following are included in the Avoided LBMP benefit:

- Avoided transmission capacity infrastructure costs built into the transmission congestion charge which are embedded in the LBMP
- Transmission-level loss costs which are embedded in the LBMP
- Compliance costs of various air pollutant emissions regulations including the value of CO_2 via the Regional Greenhouse Gas Initiative and the values of SO_2 and NO_x via cap-and-trade markets which are embedded in the LBMP

Depending on a project's location on the system, distribution losses can also affect LBMP purchases, and this effect should be reflected in the calculation of LBMP benefits.[18] To the extent a project changes the electrical topology and the distribution loss percent, the incremental changes in distribution losses would be allocated to the Avoided Distribution Losses benefit. Similarly, there may be projects that would specifically impact Avoided Transmission Capacity or change the transmission loss percent. In these instances, the impacts would be captured outside of the Avoided LBMP benefit.

2.2 Incorporating Losses into Benefits

Many of the benefit equations provided in Section 4 include a parameter to account for losses. In calculating a benefit or cost resulting from load impacts, losses occurring upstream from the load impact must be accounted to arrive at the total energy or demand impact. Losses can be accounted for either by adjusting the impact parameter or the valuation parameter. For consistency, all equations in Section 4 are shown with a loss adjustment to the impact parameter.

The following losses-related nomenclature is used in the BCA Handbook:

- **Losses (MWh or MW)** are the difference between the total electricity send-out and the total output as measured by revenue meters. This difference includes technical and non-technical losses. Technical losses are the losses associated with the delivery of electricity of energy and have fixed (no load) and variable (load) components. Non-technical losses represent electricity that is delivered, but not measured by revenue meters.
- **Loss Percent (%)** are the total fixed and/or variable[19] quantity of losses between relevant voltage levels divided by total electricity send-out unless otherwise specified.
- **Loss Factor (dimensionless)** is a conversion factor derived from "loss percent." The loss factor is 1 / (1 - Loss Percent).

For consistency, the equations in Section 4 follow the same notation to represent various locations on the system:

- "r" subscript represents the retail delivery point or point of connection of a DER, for example distribution secondary, distribution primary, or transmission.[20]
- "i" subscript represents the interface of the distribution and transmission systems.

[18] For example, an impact on the secondary distribution system compared to the primary system will have a higher impact on the LBMP purchases due to higher losses.
[19] In the BCA equations outlined in Section 4 below, project-specific energy and demand impacts at the retail delivery point are adjusted to the bulk system (or other relevant system location) based on *only* the variable component of the loss percent. In cases where the transmission or distribution loss percent is altered due to a project, the fixed and/or variable loss percent impacts are considered.
[20] Transmission in this context refers to the distribution utility's sub-transmission and internal transmission.

- "b" subscript represents the bulk system which is the level at which the values for AGCC and LBMP are provided.

Based on the notation described above, if a residential customer is connected to distribution secondary the loss percent parameter called $\mathrm{Loss\%}_{\mathrm{b} \rightarrow \mathrm{r}}$ would represent the loss percent between the bulk system ("b") and the retail delivery or connection point ("r"). In this example, the loss percent would be the sum of the distribution secondary, distribution primary, and transmission loss percentages. If a large commercial customer is connected to primary distribution the appropriate loss percent would be the sum of distribution primary and transmission loss percentages.

2.3 Establishing Credible Baselines

One of the most significant challenges associated with evaluating the benefit of a grid or DER project or program is establishing baseline data that illustrates the performance of the system without the project or program. The utility may derive baseline estimates from recent historical data, forecasts, statistical or model-based projections, or comparison/control groups (e.g., similar feeders and households) during the project.

Sound baseline data is crucial in measuring the incremental impact of the technology deployment. The benefits of grid modernization projects accrue over many years; thus, baselines must be valid across the same time horizon. This introduces the following considerations:

- **Forecasting market conditions**: Project impacts as well as benefit and cost values are affected by market conditions. For example, the Commission has directed that Avoided LBMP should be calculated based on NYISO's CARIS Phase 2 economic planning process base case LBMP forecast. However, the observed benefit of a project will be different if the wholesale energy market behaves differently from the forecasted trends.
- **Forecasting operational conditions**: Many impacts and benefits are tied to how the generation, transmission, and distribution infrastructure are operated. In this example, the Commission indicated that benefits associated with avoided CO_2 emissions shall be based on the change in the tons of CO_2 produced by the bulk system when system load levels are reduced by 1%. It is important to note that this impact calculation is an approximation and it is still very difficult to determine the actual CO_2 reductions at the bulk system level from the impacts of projects implemented at the distribution system level. Project-specific reductions are tied to dispatch protocols based on the optimized operation of the bulk system given a set of preventive post-contingency settings. In addition, the carbon intensity of the generation mix will inevitably change over time independent of any investment at the distribution level.
- **Predicting asset management activities**: Some impacts and benefits, such as Avoided Distribution Capacity Infrastructure, are affected by distribution-level capital investments that may be made independent of the projects being evaluated. In this example, the amount of available excess capacity may change if key distribution assets are replaced and uprated.
- **Normalizing baseline results**: Baseline data should be normalized to reflect average conditions over the course of a year. This is likely to involve adjustments for weather and average operational characteristics.

There are significant uncertainties surrounding the benefits and costs. Regulatory approvals, technological advances, operational budgets, and other business conditions all affect the cost of deployment, and/or expected system performance. As such, the utility may re-evaluate and revise its baseline data as significant events or developments alter the assumed or implied conditions of the current baseline.

2.4 Establishing Appropriate Analysis Time Horizon

The duration over which the impact and benefits of new grid and DER investments accrue varies significantly. The time horizon for the analysis must consider several factors, including differences among the lengths of expected useful life of various hardware and software across multiple projects and how to reconcile the differences in these lengths of expected useful lives. The analysis timeframe should be based on the longest asset life included in the portfolio/solution under consideration.[21]

2.5 Granularity of Data for Analysis

The most accurate assumptions to use for performing a BCA would leverage suitable locational or temporal information. When the more granular data is not available, an appropriate annual average or system average maybe used, to reflect the expected savings from use of DER.

While more granular locational or temporal assumptions are always preferred to capture the savings more accurately from use of a resource, the methodology included in the BCA Handbook would accommodate appropriate system averages in cases where more data is not available.

2.6 Performing Sensitivity Analysis

The *BCA Order* indicates the BCA Handbook shall include a “description of the sensitivity analysis that will be applied to key assumptions.”[22] As Section 4 indicates, a sensitivity analysis may be performed on any of the benefits and costs, and a sensitivity analysis may be performed on any of the benefits and costs by changing selected input parameters.

The largest benefits for DER are typically the bulk system benefits, Avoided LBMP and AGCC.
A sensitivity of LBMP, $/MWh, could be assessed by adjusting the LBMP by +/-10%.
In addition to adjusting the values of an individual parameter as a sensitivity, the applicability of certain benefits and costs would be considered as a sensitivity analysis of the cost-effectiveness tests. For example, inclusion of the wholesale market price impacts in the UCT and RIM would be assessed as a sensitivity.[23]

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[21] REV Proceeding, BCA Order, p. 2.
[22] REV Proceeding, BCA Order, Appendix C, p. 31.
[23] REV Proceeding, BCA Order, p. 25.

3. RELEVANT COST-EFFECTIVENESS TESTS

The BCA Order states that the Societal Cost Test (SCT), Utility Cost Test (UCT), and the Rate Impact Measure (RIM) make up the relevant cost-effectiveness tests to be used in the BCA. These cost-effectiveness tests are summarized in Table 3-1.

Table 3-1. Cost-Effectiveness Tests

Cost Test	Perspective	Key Question Answered	Calculation Approach
SCT	Society	Is the State of New York better off as a whole?	Compares the costs incurred to design and deliver projects, and customer costs with avoided electricity and other supply-side resource costs (e.g., generation, transmission, and natural gas); also includes the cost of externalities (e.g., carbon emissions and other net non-energy benefits)
UCT	Utility	How will utility costs be affected?	Compares the costs incurred to design, deliver, and manage projects by the utility with avoided electricity supply-side resource costs
RIM	Ratepayer	How will utility rates be affected?	Compares utility costs and utility bill reductions with avoided electricity and other supply-side resource costs

The BCA Order positions the SCT as the primary cost-effectiveness measure because it evaluates impact on society as a whole.

The role of the UCT and RIM is to assess the preliminary impact on utility costs and customer bills from the benefits and costs that pass the SCT. The results of the UCT and RIM test are critical in identifying projects that may require a more detailed analysis of their impact to the utility and customers. Some projects may not provide benefits to the utility and customers, even if it is a benefit to society. It is important to note, however, that if a measure passes the SCT but its results do not satisfy the UCT and RIM tests, the measure would not be rejected unless a complete bill impact analysis determines that such impact is of a "magnitude that is unacceptable".[24]

Each cost-effectiveness test included in the BCA Framework is defined in greater detail in the following subsections. Which of the various benefits and costs to include in analysis of individual projects or investment portfolios requires careful consideration, as discussed in Section 2 General Methodological Considerations.

[24] REV Proceeding, BCA Order, p. 13.

Table 3-2 summarizes which cost-effectiveness tests can be applied to the benefits and costs included in the *BCA Order*. The subsections below provide further context for each cost-effectiveness test.

Table 3-2. Summary of Cost-Effectiveness Tests by Benefit and Cost

Section #	Benefit/Cost	SCT	UCT	RIM
	Benefit			
4.1.1	Avoided Generation Capacity Costs†	✓	✓	✓
4.1.2	Avoided LBMP‡	✓	✓	✓
4.1.3	Avoided Transmission Capacity Infrastructure†‡	✓	✓	✓
4.1.4	Avoided Transmission Losses†‡	✓	✓	✓
4.1.5	Avoided Ancillary Services*	✓	✓	✓
4.1.6	Wholesale Market Price Impacts**		✓	✓
4.2.1	Avoided Distribution Capacity Infrastructure	✓	✓	✓
4.2.2	Avoided O&M	✓	✓	✓
4.2.3	Avoided Distribution Losses†‡	✓	✓	✓
4.3.1	Net Avoided Restoration Costs	✓	✓	✓
4.3.2	Net Avoided Outage Costs	✓		
4.4.1	Net Avoided CO_2‡	✓		
4.4.2	Net Avoided SO_2 and NO_x‡	✓		
4.4.3	Avoided Water Impacts	✓		
4.4.4	Avoided Land Impacts	✓		
4.4.5	Net Non-Energy Benefits***	✓	✓	✓
	Cost			
4.5.1	Program Administration Costs	✓	✓	✓
4.5.2	Added Ancillary Service Costs*		✓	✓
4.5.3	Incremental T&D and DSP Costs	✓	✓	✓
4.5.4	Participant DER Cost	✓		
4.5.5	Lost Utility Revenue			✓
4.5.6	Shareholder Incentives			✓
4.5.7	Net Non-Energy Costs**	✓	✓	✓

† See Section 2 for discussion of potential overlaps in accounting for these benefits.
‡ See Section 2.1.2.1 for discussion of potential overlaps in accounting for these benefits.
** The amount of DER is not the driver of the size of NYISO's ancillary services markets since a change in load will not result in a reduction in the NYISO requirements for regulation and reserves as the requirements for these services are set periodically by NYISO to maintain frequency and to cover the loss of the largest supply element(s) on the bulk power system. Therefore, there is no impact within the SCT as the overall ancillary services requirement remains unchanged. DER has potential to provide new distribution-level ancillary service. However, it is uncertain whether such service can be cost-effectively provided.*
*** The Wholesale Market Price Impacts in the UCT and RIM would be assessed as a sensitivity.*
**** It is necessary to identify which cost-effectiveness test should include the specific benefit or cost in the Net Non-Energy Benefit or Net Non-Energy Cost as it may apply to the SCT, UCT and/or RIM.*

Performing a cost-effectiveness test for a specific project or a portfolio of projects requires the following steps:

- **Select the relevant benefits** for the investment.
- **Determine the relevant costs** from each cost included over the life of the investment.
- **Estimate the impact** the investment will have in each of the relevant benefit categories for each year of the analysis period (i.e., how much it will change the underlying physical operation of the electric system to produce the benefits).
- **Apply the benefit values** associated with the project impacts as described in Section 4.
- **Apply the appropriate discount rate** to perform a cost-effectiveness test for a specific project or portfolio. The discount rate is the utility weighted average cost of capital to determine the present value of all benefits and costs.
- **Treat inflation consistently** by discounting real cash flow by real discount rates and nominal cash flows by nominal discount rates. Annual price index inflation rates as published by the Federal Reserve Bank at the time of filing[25] should be assumed unless otherwise specified.

3.1 Societal Cost Test

Cost Test	Perspective	Key Question Answered	Calculation Approach
SCT	Society	Is the State of New York better off as a whole?	Compares the costs incurred to design and deliver projects, and customer costs with avoided electricity and other supply-side resource costs (e.g., generation, transmission, and natural gas); also includes the cost of externalities (e.g., carbon emissions, and net non-energy benefits)

Most of the benefits included in the BCA Order can be evaluated under the SCT because their impact applies to society as a whole. This includes all distribution system benefits, all reliability/resiliency benefits, and all external benefits.

Lost Utility Revenue and Shareholder Incentives do not apply to the SCT, as these are considered transfers between stakeholder groups that have no net impact on society.

Similarly, the Wholesale Market Price Impact sensitivity is not performed for the SCT because the price suppression is also considered a transfer from large generators to market participants.[26]

[25] Federal Reserve Bank Philadelphia: https://www.philadelphiafed.org/research-and-data/real-time-center/survey-of-professional-forecasters.
[26] REV Proceeding, BCA Order, p. 24.

3.2 Utility Cost Test

Cost Test	Perspective	Key Question Answered	Calculation Approach
UCT	Utility	How will utility costs be affected?	Compares the costs incurred to design, deliver, and manage projects by the utility with avoided electricity supply-side resource costs

The UCT looks at the impact to utility costs associated with energy, capacity, generation, T&D, overhead, and general and administrative. For this reason, external benefits such as Avoided CO_2, Avoided SO_2 and NO_X, and Avoided Water and Land Impacts are not considered in the UCT. Utilities in New York do not currently receive incentives for decreased CO_2 or other environmental impacts. Benefits related to avoided outages would go to customers and not utilities, so this benefit also does not apply to the UCT.

Participant DER Cost and Lost Utility Revenue are not considered in the UCT because the cost of the DER is not a utility cost and any reduced revenues from DER are made-up by non-participating DER customers through the utility's revenue decoupling mechanism or other means.

3.3 Rate Impact Measure

Cost Test	Perspective	Key Question Answered	Calculation Approach
RIM	Ratepayer	How will utility rates be affected?	Compares utility costs and utility bill reductions with avoided electricity and other supply-side resource costs

The RIM test can address rate impacts to non-participants. External benefits such as Avoided CO_2, Avoided SO_2 and NO_X, and Avoided Water and Land Impacts are not included in the RIM as they do not directly affect customer rates. Benefits related to avoided outages go to customers but, again, would have no effect on rates.

Participant DER cost does not apply to the RIM because the cost of the DER is not a utility cost. However, any reduced revenues from DER are included as increased costs to other customers as Lost Utility Revenue because of revenue decoupling or other means that transfer costs from participants to non-participants.

4. BENEFITS AND COSTS METHODOLOGY

Each subsection below aligns with a benefit or cost listed in the BCA Order. Each benefit and cost include a definition, equation, and a discussion of general considerations.

Four types of benefits are addressed in the subsections below:

- Bulk System: Larger system responsible for the generation, transmission and control of electricity that is passed on to the local distribution system.
- Distribution System: System responsible for the local distribution of electricity to end use customers.
- Reliability/Resiliency: Efforts made to reduce duration and frequency of outages.
- External: Consideration of social values for incorporation in the SCT.

There are also four types of costs considered in the BCA Framework and addressed in the subsections below. They are:

- Program Administration: Includes the cost of state incentives, measurement and verification, and other program administration costs to start, and maintain a specific program.
- Utility-related: Those incurred by the utility such as incremental T&D, DSP, lost revenues and shareholder incentives
- Participant-related: Those incurred to achieve project or program objectives
- Societal: External costs for incorporation in the SCT

The 2023 BCA Handbook v4.0 assumes that all energy, operational, and reliability-related benefits and costs,[27] occur in the same year. Thus, there is no time delay between benefit/cost impacts. However, for capacity and infrastructure benefits and costs,[28] it is assumed that impacts generate benefits/costs in the following year of the impact. For example, if a project reduces system peak load in 2023, the AGCC benefit would not be realized until 2024.

4.1 Bulk System Benefits

4.1.1 Avoided Generation Capacity Costs

Avoided Generation Capacity Costs are due to reduced coincident system peak demand. This benefit is calculated by NYISO zone, which is the most granular level for which AGCC are currently available.[29] It is assumed that the benefit is realized in the year following the peak load reduction impact.

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[27] Energy, operational, and reliability-related benefits and costs include: Avoided LBMP, the energy component of Avoided Transmission Losses, Avoided Ancillary Services (Spinning Reserves, and Frequency Regulation), the energy portion of Wholesale Market Price Impact, Avoided O&M, Avoided Distribution Capacity Infrastructure, Avoided Restoration, Net Avoided Outage Costs, the energy component of Distribution Losses, Net Avoided CO_2, Net Avoided SO_2 and NO_X, Avoided Water Impact, Avoided Land Impact, Net Non-Energy Benefits Related to Utility or Grid Operations, Program Administration Costs, Participant DER Cost, Lost Utility Revenue, Shareholder Incentives, and Net Non-Energy Costs.

[28] Capacity, infrastructure, and market price-related benefits and costs include: Avoided Generation Capacity Costs, the capacity component of Avoided Transmission Losses, Avoided O&M, the capacity component of Distribution Losses, Avoided Transmission Capacity Infrastructure and Related O&M, the capacity portion of the Wholesale Market Price Impact, Added Ancillary Service Costs, and Incremental Transmission & Distribution and DSP Costs.

[29] For a portfolio of projects located within multiple NYISO zones, it may be necessary to calculate weighted average across zones to obtain a benefit value.

4.1.1.1 *Benefit Equation, Variables, and Subscripts*

Equation 4-1 presents the benefit equation for Avoided Generation Capacity Costs. This equation follows "Variant 1" of the Demand Curve savings estimation described in the 2019 Congestion Assessment and Resource Integration Study (CARIS) Appendix. Each NYISO zone is mapped to one of the four NYISO localities as follows: ROS = A-F, LHV = G-I, NYC = J, LI = K.

Equation 4-1. Avoided Generation Capacity Costs

$$\mathrm{Benefit}_{\mathrm{Y+1}} = \sum_{Z} \frac{\Delta\mathrm{PeakLoad}_{\mathrm{Z,Y,r}}}{1\text{-}\mathrm{Loss\%}_{\mathrm{Z,Y,b}\rightarrow\mathrm{r}}} * \mathrm{SystemCoincidenceFactor}_{\mathrm{Z,Y}} * \mathrm{DeratingFactor}_{\mathrm{Z,Y}} * \mathrm{AGCC}_{\mathrm{Z,Y,b}}$$

The indices of the parameters in Equation 4-1 include:

- Z = NYISO zone (A → K)
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

ΔPeakLoad$_{\mathrm{Z,Y,r}}$ (ΔMW) is the project's expected maximum demand reduction capability, or "nameplate" impact at the retail delivery or connection point ("r"), by zone if applicable. This input is project or program specific. A positive value represents a reduction in peak load.

Loss%$_{\mathrm{Z,b}\rightarrow\mathrm{r}}$ (%) is the variable loss percent between bulk system ("b") and the retail delivery or connection point ("r"). The loss percentages by system level are found in Table A-2.

SystemCoincidenceFactor$_{\mathrm{Z,Y}}$ (dimensionless) captures a project's or program's contribution to reducing bulk system peak demand relative to its expected maximum demand reduction capability. For example, a nameplate demand reduction capacity of 100 kW with a system coincidence factor of 0.8 would reduce the bulk system peak demand by 80 kW. This input is project specific.

DeratingFactor$_{\mathrm{Z,Y}}$ (dimensionless) is presented here as a factor to de-rate the coincident peak load reduction based on the availability of a resource during system peak hours. For example, a demand response program may only be allowed to dispatch a maximum of 10 events per year, which could limit the availability of the resource during peak hours. Another example is the variability and intermittence (e.g., due to clouds) of a solar array which could limit its contribution to system peak load reduction. This input is project specific.

$AGCC_{Z,Y,b}$ ($/MW-yr) represents the annual AGCCs at the bulk system ("b") based on forecast of capacity prices for the wholesale market provided by DPS Staff and posted on DMM under Case 14-M-0101. This data can be found in Staff's ICAP Spreadsheet Model in the "AGCC Annual" tab in the "Avoided GCC at Transmission Level" table. This spreadsheet converts "Generator ICAP Prices" to "Avoided GCC at Transmission Level" based on capacity obligations for the wholesale market. Note that the AGCC values provided in this spreadsheet are in the units of $/kW-mo, which must be converted to $/MW-yr to match the peak load impact in MW. To convert units, the summer and winter $/kW-mo values are multiplied by six months each and added together, and then multiplied by 1,000 to convert to $/MW-yr. AGCC costs are calculated based on the NYISO's capacity market demand curves, using supply and demand by NYISO zone, Minimum Locational Capacity Requirements (LCR), and the Reserve Margin.

4.1.1.2 General Considerations

The AGCC forecast provided by Staff is based on capacity market demand curves using the demand forecasts and available supply from NYISO's Load & Capacity Data report. CARIS can be used for guidance on how demand curves are applied to the AGCC forecast.[30] The Reserve Margin is determined annually by New York State Reliability Council. Minimum LCR, set by NYISO, are applicable to several localities (NYC, LI, "G-J" Region) and account for transmission losses. See NYISO Installed Capacity Manual[31] for more details on ICAP.

AGCC benefits are calculated using a static forecast of AGCC prices provided by Staff. Any wholesale market capacity price suppression effects are not accounted for here and instead are captured in Wholesale Price Impacts, described in Section 4.1.6.

Impacts from a measure, project, or portfolio must be coincident with the system peak and account for losses prior to applying the AGCC valuation parameter. The "nameplate" impact (i.e., $\Delta PeakLoad_{Z,Y,r}$) should also be multiplied by a coincidence factor and derating factor to properly match the planning impact to the system peak. The coincident factor quantifies a project's contribution to system peak relative to its nameplate impact.

It is also important to consider the persistence of impacts in future years after a project's implementation. For example, participation in a demand response program may change over time. Also, a peak load reduction impact will not be realized as a monetized AGCC benefit until the year following the peak load reduction, as capacity requirements are set by annual peak demand and paid for in the following year.

The AGCC values provided in Staff's ICAP Spreadsheet Model account for the value of transmission losses and infrastructure upgrades. In instances where projects change the transmission topology, incremental infrastructure and loss benefits not captured in the AGCC values should be modeled and quantified in the Avoided T&D Losses and Avoided T&D Infrastructure benefits, below.

4.1.2 Avoided LBMPs

Avoided LBMP is avoided energy purchased at the Locational Based Marginal Price (LBMP). The three components of the LBMP (i.e., energy, congestion, and losses) are all included in this benefit. See Section 2.1.2.1 for details on how the methodology avoids double counting between this benefit and others.

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[30] 2019 CARIS Phase 1 Study Appendix: https://dps.ny.gov/electric-service-reliability-report-2021.
[31] The NYISO Installed Capacity Manual (4) (issued April 27, 2023): https://www.nyiso.com/documents/20142/2923301/icap_mnl.pdf/234db95c-9a91-66fe-7306-2900ef905338.

4.1.2.1 Benefit Equation, Variables, and Subscripts

Equation 4-2 presents the benefit equation for Avoided LBMP:

Equation 4-2. Avoided LBMP

$$\text{Benefit}_{\text{Y}} = \sum_{\text{Z}} \sum_{\text{P}} \frac{\Delta\text{Energy}_{\text{Z,P,Y,r}}}{1 - \text{Loss\%}_{\text{Z,b}\rightarrow\text{r}}} * \text{LBMP}_{\text{Z,P,Y,b}}$$

The indices of the parameters in Equation 4-2 include:

- Z = zone (A → K)
- P = period (e.g., year, season, month, and hour)
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

ΔEnergy$_{Z,P,Y,r}$ (ΔMWh) is the difference in energy purchased at the retail delivery or connection point (“r”) as the result of project implementation, by NYISO zone and by year with time-differentiated periods, for example, annual, seasonal, monthly, or hourly as appropriate. This parameter represents the energy impact at the project location and is **not** yet grossed up to the LBMP location based on the losses between those two points on the system. This adjustment is performed based on the $Loss\%_{Z,b\rightarrow r}$ parameter. This input is project or program-specific. A positive value represents a reduction in energy.

Loss%$_{Z,b\rightarrow r}$ (%) is the variable loss percent between bulk system (“b”) and the retail delivery or connection point (“r”). The loss percentages by system level are found in Table A-2.

LBMP$_{Z,P,Y,b}$ (\$/MWh) is the Locational Based Marginal Price, which is the sum of energy, congestion, and losses components by NYISO zone at the bulk system level (“b”). NYISO forecasts 20-year annual and hourly LBMPs by zone. To determine time-differentiated LBMPs, for example, annual, seasonal, monthly, or hourly, leverage NYISO’s hourly LBMP forecast by zone rather than developing an alternative forecast of time-differentiated LBMPs based on shaping annual averages by zone from historical data. The NYISO hourly LBMP forecast is a direct output from the CARIS Phase 2 modeling. To extend the LBMP forecast beyond the CARIS Phase 2 planning period, if necessary, assume that the last year of the LBMPs stay constant in real (inflation adjusted) $/MWh.

4.1.2.2 General Considerations

Avoided LBMP benefits are calculated using a static forecast of LBMP. Any wholesale market price changes as a result of the project or program are not accounted for in this benefit, and are instead captured in Wholesale Market Price Impacts, described in Section 4.1.6.

The time differential for subscript P (period) will depend on the type of project, and could be season, month, day, hour, or any other interval. The user must ensure that the time-differentiation is appropriate for the project being analyzed. For example, it may be appropriate to use an annual average price and impact for a DER that has a consistent load reduction at all hours of the year. However, using the annual average may not be appropriate for energy storage which may be charging during non-peak hours and discharging during peak hours. In that case, it may be appropriate to multiply an average on-peak (or super-peak) and off-peak LBMP by the on-peak (or super-peak) and off-peak energy impacts, respectively.

For electric demand-side management programs, a multiplier will be applied to the winter avoided LBMP benefit calculations based on the number of peak days active.

It is important to consider the trend (i.e., system degradation) of impacts in future years after a project's implementation. For example, a PV system's output may decline over time. It is assumed that the benefit is realized in the year of the energy impact.

4.1.3 Avoided Transmission Capacity Infrastructure and Related O&M

Avoided Transmission Capacity Infrastructure and Related O&M benefits result from location-specific load reduction that is valued at the marginal cost of equipment that is avoided or deferred by a DER project or program. A portion of Avoided Transmission Capacity is already captured in the congestion charge of the LBMP and the AGCC prices. Because static forecasts of LBMPs and AGCC values are used, this benefit will be quantified only in cases where a measure, project, or portfolio alters the planned transmission system investments from that level embedded in those static forecasts.

4.1.3.1 Benefit Equation, Variables, and Subscripts

Equation 4-3 presents the benefit equation for Avoided Transmission Capacity Infrastructure and Related O&M:

Equation 4-3. Avoided Transmission Capacity Infrastructure and Related O&M

$$\mathrm{Benefit}_{\mathrm{Y+1}} = \sum_{\mathrm{C}} \frac{\Delta \mathrm{PeakLoad}_{\mathrm{Y,r}}}{1 - \mathrm{Loss\%}_{\mathrm{Y,b \to r}}} * \mathrm{TransCoincidentFactor}_{\mathrm{C,Y}} * \mathrm{DeratingFactor}_{\mathrm{Y}} * \mathrm{MarginalTransCost}_{\mathrm{C,Y,b}}$$

The indices[32] of the parameters in Equation 4-3 include:

- C = constraint on an element of transmission system[33]
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

$\boldsymbol{\Delta \mathrm{PeakLoad}_{\mathrm{Y,r}}}$ **(ΔMW)** is the project's expected maximum demand reduction capability, or "nameplate" impact at the retail delivery or connection point ("r"). This input is project specific. A positive value represents a reduction in peak load.

$\boldsymbol{\mathrm{Loss\%}_{\mathrm{Y,b \to r}}}$ **(%)** is the variable loss percent between the bulk system ("b") and the retail delivery point ("r"). Thus, this reflects the sum of the transmission and distribution system loss percent values, both found in Table A-2.

$\mathrm{TransCoincidentFactor}_{\mathrm{C,Y}}$ (dimensionless) quantifies a project's contribution to reducing transmission system peak demand relative to its expected maximum demand reduction capability. For example, an expected maximum demand reduction capability of 100 kW with a coincidence factor of 0.8 will reduce the transmission system peak by 80 kW (without considering $DeratingFactor_Y$). This input is project specific.

[32] In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.
[33] If system-wide marginal costs are used, this is not an applicable subscript.

$\mathbf{DeratingFactor_Y}$ **(dimensionless)** is presented here as a generic factor to de-rate the transmission system coincident peak load based on the availability of the load during peak hours. For example, a demand response program may only be allowed to dispatch a maximum of 10 events per year, which could limit the availability of the resource during peak hours. Another example is the variability and intermittence (e.g., due to clouds) of a solar array which could limit its contribution to peak load reduction on the transmission system. This input is project specific.

$\mathbf{MarginalTransCost_{C,Y,b}}$ **($/MW-yr)** is the marginal cost of the transmission equipment from which the load is being relieved. It is assumed that the marginal cost of service is based on the bulk system ("b"). If the available marginal cost of service value reflects a different basis, then this parameter must first be converted to represent load at the bulk system prior to using in the equation above. Localized or equipment-specific marginal costs of service should be used in most cases. In some limited circumstances, use of the system average marginal cost have been accepted, for example, for evaluation of energy efficiency programs. Con Edison's marginal cost of service study results on a system-average basis are reflected in Table A-3 below.

4.1.3.2 General Considerations

In order to find the impact of the measure, project, or portfolio on the transmission system peak load, the "nameplate" capability or load impact must be multiplied by the transmission system coincidence factor and derating factor. Coincidence factors and derating factors would need to be determined by a project-specific engineering study.

Some transmission capacity costs are already embedded in both LBMP and AGCC. Both the AGCC and transmission congestion charges could be decreased in the event that additional transmission assets are built, or load is reduced. To the extent that deferred or avoided transmission upgrades are incremental to the value captured in LBMP and AGCC and can be modeled or calculated, these benefits would be reported in this benefit. This value would need to be project-specific based on the specific deferral and/or change to the system topology rather than through generic utility marginal cost of service studies. Using system average marginal costs to estimate avoided transmission and infrastructure need may result in significant over- or under-valuation of the benefits and/or costs and may result in no savings for customers.

The use of project-specific values helps ensure that the calculated impact is applicable to the specific impact of the project both on a temporal and locational basis, adjusting for losses (i.e., locational alignment) and coincidence with the transmission peak (i.e., temporal alignment). In other words, the load reduction ultimately used to value this benefit must be coincident with the load on the relieved equipment. It is important to distinguish between system and local constraints in order to match the impact with the avoided cost. It is assumed that the marginal cost of service is based on the load at the bulk system. If the available marginal cost of service value is based on a different location in the system (e.g., interface between transmission and distribution), then this parameter must first be converted to represent load at the bulk system prior to using in the equation above.

Avoided transmission infrastructure cost benefits are realized only if the project improves load profiles that would otherwise create a need for incremental infrastructure. Benefits are only accrued when a transmission constraint is relieved due to coincident peak load reduction from DER. Under constrained conditions, it is assumed that a peak load reduction impact will produce benefits in the following year as the impact. Once the peak load reduction is less than that necessary to avoid or defer the transmission investment and infrastructure must be built, or the constraint is relieved, this benefit would not be realized from that point forward.

The marginal cost of transmission capacity values provided in Table A-3 include both capital and O&M which cannot be split into two discrete benefits. Therefore, care should be taken to avoid double counting of any O&M values included in this benefit and part of the Avoided O&M benefit described in Section 4.2.2.

4.1.4 Avoided Transmission Losses

Avoided Transmission Losses are realized when a project changes the topology of the transmission system that results in a change to the transmission system loss percent. Reductions in end use consumption and demand that result in reduced losses are included in Avoided LBMP and Avoided Generation Capacity benefits as described above in Sections 4.1.2 and 4.1.1. While both the LBMP and AGCC will adjust to a change in system losses in future years, the static forecast used in this methodology does not capture these effects.

4.1.4.1 Benefit Equation, Variables, and Subscripts

Equation 4-4 presents the benefit equation for Avoided Transmission Losses:

Equation 4-4. Avoided Transmission Losses

$$\mathrm{Benefit}_{Y+1} = \sum_{Z} \mathrm{SystemEnergy}_{Z,Y+1,b} * \mathrm{LBMP}_{Z,Y+1,b} * \Delta\mathrm{Loss\%}_{Z,Y+1,b\to i} + \mathrm{SystemDemand}_{Z,Y,b} * \mathrm{AGCC}_{Z,Y,b} * \Delta\mathrm{Loss\%}_{Z,Y,b\to i}$$

Where,

$$\Delta\mathrm{Loss\%}_{Z,Y,b\to i} = \mathrm{Loss\%}_{Z,Y,b\to i,\mathrm{baseline}} - \mathrm{Loss\%}_{Z,Y,b\to i,\mathrm{post}}$$

The indices[34] of the parameters in Equation 4-4 include:

- Z = NYISO zone (for LBMP: A → K; for AGCC: NYC, LHV, LI, ROS[35])
- Y = Year
- b = Bulk System
- i = Interface of the transmission and distribution systems

SystemEnergy$_{Z,Y+1,b}$ (MWh) is the annual energy forecast by NYISO in the Load & Capacity Report at the bulk system (“b”) level; it includes both transmission and distribution losses. Total system energy is used for this input, rather than the project-specific energy, because this benefit is only included in the BCA when a change in system topology produces a change in the transmission loss percent, which affects all load in the relevant area.

LBMP$_{Z,Y+1,b}$ ($/MWh) is the LBMP, which is the sum of energy, congestion, and losses components by NYISO zone at the bulk system level (“b”). To determine time-differentiated LBMPs, for example, annual, seasonal, monthly, or hourly, leverage NYISO’s hourly LBMP forecast by zone rather than developing an alternative forecast of time-differentiated LBMPs based on shaping annual averages by zone from historical data. The NYISO hourly LBMP forecast is a direct output from the CARIS Phase 2 modeling. To extend the LBMP forecast beyond the CARIS planning period, if necessary, assume that the last year of the LBMPs stay constant in real (inflation adjusted) $/MWh.

[34] In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.
[35] Mapping NYISO localities to NYISO zones: ROS = A-F, LHV = G-I, NYC = J, LI = K.

SystemDemand$_{\mathbf{Z,Y,b}}$ (MW) is the system peak demand forecast by NYISO at the bulk system level ("b"), which includes transmission and distribution losses by zone. System demand is used in this evaluation rather than the project-specific demand, because this benefit is only quantified when a change in system topology produces a change in the transmission losses percent, which affects all load in the relevant zone.

AGCC$_{\mathbf{Z,Y,b}}$ ($/MW-yr) represents the annual AGCCs based on forecast of capacity prices for the wholesale market provided by Staff. This data is posted on DMM in Case 14-M-0101[36] and can be found in Staff's ICAP Spreadsheet Model in the "AGCC Annual" tab in the "Avoided GCC at Transmission Level" table. This spreadsheet converts "Generator ICAP Prices" to "Avoided GCC at Transmission Level"[37] based on capacity obligations at the forecast of capacity prices for the wholesale market. Note that the AGCC values provided in this spreadsheet are in the units of $/kW-mo, which must be converted to $/MW-yr to match the peak load impact in MW. To convert units, the summer and winter $/kW-mo values are multiplied by six months each and added together, and then multiplied by 1,000 to convert to $/MW-yr.

ΔLoss%$_{\mathbf{Z,Y,b \rightarrow i}}$ (Δ%) is the change in fixed and variable loss percent between the bulk system ("b") and the interface of the transmission and distribution systems ("i") resulting from a project that changes the topology of the transmission system. This value would typically be determined in a project-specific engineering study. Two parameters are provided in the equations above: one with a "Y" subscript to represent the current year, and one with a "Y+1" subscript to represent the following year.

Loss%$_{\mathbf{Z,Y,b \rightarrow i,baseline}}$ (%) is the baseline fixed and variable loss percent between bulk system ("b") and the interface of the transmission and distribution systems ("i"). Thus, this reflects the sub-transmission and internal transmission losses pre-project, which is found in Table A-2.

Loss%$_{\mathbf{Z,Y,b \rightarrow i,post}}$ (%) is the post-project fixed and variable loss percent between bulk system ("b") and the interface of the transmission and distribution systems ("i"). Thus, this reflects the sub-transmission and internal transmission losses post-project.

4.1.4.2 General Considerations

Transmission losses are already embedded in the LBMP. This benefit is incremental to what is included in LBMP and is only quantified when the transmission loss percent is changed (e.g., from 3% to 2.9%). For most projects, this benefit will be zero unless an engineering study determines otherwise.

The energy and demand impacts are based on system-wide energy and demand rather than project-specific, because this benefit is only quantified when the losses percentage is changed which affects all customers in the affected area. Transmission losses will not affect downstream distribution losses.

It is assumed that the LBMP component of the avoided losses benefit is accrued in the same year as the impact, and the AGCC component of the benefit is accrued in the following year of the benefit. This is reflected in the equation above with "Y" and "Y+1" subscripts to indicate the timing of the benefits relative to the impacts.

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[36] Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*: http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-M-0101&submit=Search.
[37] "Transmission level" represents the bulk system level ("b").

4.1.5 Avoided Ancillary Services (Spinning Reserves, and Frequency Regulation)

Avoided Ancillary Services benefits may accrue to select DER that qualify and are willing and able to provide ancillary services to NYISO at a lower cost than conventional generators without sacrificing reliability. This benefit will only be quantified in cases where a measure, project, or portfolio is qualified to, or has the ability and willingness to provide ancillary services to NYISO. This value will be zero for nearly all cases and by exception would be a value included as part of the UCT and RIM.

As a load modifier, DER causes a reduction in load however, it will not directly result in a reduction in NYISO requirements for regulation and reserves since these requirements are not based on existing load levels but instead are based on available generating resource characteristics. Regulation requirements are set by NYISO to maintain frequency, and reserve requirements are set to cover the loss of the largest supply element(s) on the bulk power system.

Some DER may have the potential to provide a new distribution-level ancillary service such as voltage support and power quality. However, it is uncertain whether such attributes can be cost-effectively provided by dispersed DER. The infrastructure costs required to monitor the applicable system conditions (voltage, flicker, etc.) and individual DER as well as the operations and communications system to effectively dispatch those DER attributes are also uncertain. It is premature to include any value in the BCA for such services until the utilities can cost-effectively build the systems to monitor and dispatch DER to capture net distribution benefits.

4.1.5.1 Benefit Equation, Variables, and Subscripts

The benefits of each of two ancillary services (spinning reserves, and frequency regulation) are described in the equations below. The quantification and inclusion of these benefits are project specific.

<u>**Frequency Regulation**</u>

Equation 4-5 presents the benefit equation for frequency regulation:

Equation 4-5. Frequency Regulation

$$\text{Benefit}_Y = \text{Capacity}_Y * n * (\text{CapPrice}_Y + \text{MovePrice}_Y * \text{RMM}_Y)$$

The indices of the parameters in Equation 4-5 include:

- Y = Year

$\mathbf{Capacity_Y}$ **(MW)** is the amount of annual average frequency regulation capacity when provided to NYISO by the project.

n (hr) is the number of hours in a year that the resource is expected to provide the service.

$\mathbf{CapPrice_Y}$ **($/MW·hr)** is the average hourly frequency regulation capacity price. The default value is the two-year historical average for day-ahead regulation capacity prices from NYISO.

$\mathbf{MovePrice_Y}$ **($/ΔMW)**: is the average hourly frequency regulation movement price. The default value is the two-year historical average for real-time dispatch of regulation movement prices from NYISO.

$\mathbf{RMM_Y}$ **(ΔMW/MW·hr)**: is the Regulation Movement Multiplier (RMM) used for regulation bids and accounts for the ratio between movement and capacity. It is assumed to be 13 ΔMW/MW-hr.

Spinning Reserves

Equation 4-6 presents the benefit equation for spinning reserves:

Equation 4-6. Spinning Reserves

$$\text{Benefit}_Y = \text{Capacity}_Y * n * \text{CapPrice}_Y$$

The indices of the parameters in Equation 4-6 include:

- Y = Year

$\mathbf{Capacity_Y}$ **(MW)** is the change in the amount of annual average spinning reserve capacity when provided to the NYISO by the project.
n (hr): is the number of hours in a year that the resource is expected to provide the service.

$\mathbf{CapPrice_Y}$ **($/MW·hr)** is the average hourly spinning reserve capacity price. The default value uses the two-year historical average spinning reserve pricing by region.

4.1.5.2 General Considerations

There are no reductions in annual average frequency regulation, and spinning reserve, because those are set by the NYISO independent of load levels and DER penetration.

The average hourly prices for frequency regulation capacity, frequency regulation movement, and spinning reserve capacity can be calculated from historical pricing data posted by NYISO. The recommended basis is a historical average of interval pricing over the prior two-year period.
The NYISO Ancillary Services Manual indicates that the day-ahead market is the predominant market for regulation capacity and spinning reserves; regulation movement is only available in real-time.
The RMM is fixed by NYISO at a value of 13 ΔMW/MW per hour. While NYISO does not publish historical interval volume data to calculate actual movement, this value can be considered a reasonable proxy for actual movement.[38]

4.1.6 Wholesale Market Price Impact

Wholesale Market Price Impact includes the benefit from reduced wholesale market prices on both energy (i.e., LBMP) and capacity (i.e., AGCC) due to a measure, project, or portfolio. LBMP impacts will be provided by Staff and are determined using the first year of the most recent CARIS 2 database to calculate the static impact on wholesale LBMP of a 1% change in the level of load that must be met.[39] LBMP impact will be calculated for each NYISO zone. AGCC price impacts are developed using Staff's ICAP Spreadsheet Model.

4.1.6.1 Benefit Equation, Variables, and Subscripts

Equation 4-7 presents the benefit equation for Wholesale Market Price Impact:

[38] NYISO Ancillary Services Manual: https://www.nyiso.com/documents/20142/2923301/ancserv.pdf/df83ac75-c616-8c89-c664-99dfea06fe2f.
[39] REV Proceeding, BCA Order, Appendix C, p. 8.

Equation 4-7. Wholesale Market Price Impact

$$\text{Benefit}_{Y+1} = \sum_{Z} (1 - \text{Hedging\%}\ ) * (\Delta\text{LBMPImpact}_{Z,Y+1,b} * \text{WholesaleEnergy}_{Z,Y+1,b} + \Delta\text{AGCC}_{Z,Y,b} * \text{ProjectedAvailableCapacity}_{Z,Y,b})$$

The indices of the parameters in Equation 4-7 include:

- Z = NYISO zone (A → K[40])
- Y = Year
- b = Bulk System

Hedging% (%) is the fraction of energy or capacity hedged via fixed price or multi-year agreements or other mechanisms. Price hedging via long term purchase contracts should be considered when assessing wholesale market price impacts. For BCA calculations the utilities have generally assumed that the percent of purchases hedged is 50% and equal for both energy and capacity.

ΔLBMPImpact$_{Z,Y+1,b}$ (Δ\$/MWh) is the change in average annual LBMP at the bulk system ("b") before and after the project(s). This will be provided by DPS Staff.

WholesaleEnergy$_{Z,Y,b}$ (MWh) is the total annual wholesale market energy purchased by zone at the bulk system level ("b"). This represents the energy at the LBMP.

ΔAGCC$_{Z,Y,b}$ (Δ\$/MW-yr) is the change in AGCC price by ICAP zone calculated from Staff's ICAP Spreadsheet Model before and after the project is implemented. This value is determined based on the difference in zonal prices in Staff's ICAP Spreadsheet Model, "AGCC Annual" tab, based on a change in the supply or demand forecast (i.e., "Supply" tab and "Demand" tab, respectively) due to the project.[41] The price impacts are based on the size and location of the project. A positive value represents a reduction in price.

ProjectedAvailableCapacity$_{Z,Y,b}$ (MW) is the projected available supply capacity by ICAP zone at the bulk system level ("b") based on Staff's ICAP Spreadsheet Model, "Supply" tab, which is the baseline before the project is implemented.

4.1.6.2 General Considerations

Wholesale market price impacts or demand reduction induced price effects are project specific based on the size and shape of the demand reduction. LBMP market price impacts will be provided by Staff and will be determined using the first year of the most recent CARIS 2 database to calculate the static impact on LBMP of a 1% change in the level of load that must be met in the utility area where the DER is located. These impacts must be considered in the benefit calculation once available. The capacity market price impacts can be calculated using Staff's ICAP Spreadsheet Model. The resultant price effects are not included in SCT but would be included in RIM and UCT as a sensitivity.

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[40] Mapping NYISO localities to NYISO zones: ROS = A-F, LHV = G-I, NYC = J, LI = K.

[41] As in the AGCC benefit equation, System Coincidence Factors and Derating Factors adjust the maximum load reduction of the project.

It is assumed that Wholesale Market Price Impacts do not result in benefits for more than one year, as these markets will respond quickly to the reduced demand thereby, reducing the benefit.[42]. As noted previously, it is also assumed that the capacity portion of Wholesale Market Price Impacts will produce benefits in the year following the impact while, the energy portion of Wholesale Market Price Impacts will produce benefits in the same year as the impact

4.2 Distribution System Benefits

4.2.1 Avoided Distribution Capacity Infrastructure

Avoided Distribution Capacity Infrastructure benefit results from location-specific distribution load reductions that are valued at the marginal cost of distribution system infrastructure that is avoided or deferred by a DER project or program. The load reduction impact must be coincident with the distribution equipment peak or otherwise defer or avoid the need for incremental distribution infrastructure based on the characteristics of the specific load and the design criteria of the specific equipment that serves it.

4.2.1.1 Benefit Equation, Variables, and Subscripts

Equation 4-8 presents the benefit equation for Avoided Distribution Capacity Infrastructure:

Equation 4-8. Avoided Distribution Capacity Infrastructure

$$\text{Benefit}_{\text{Y}} = \sum_{\text{V}} \sum_{\text{C}} \frac{\Delta\text{PeakLoad}_{\text{Y,r}}}{1 - \text{Loss\%}_{\text{Y,b}\rightarrow\text{r}}} * \text{DistCoincidentFactor}_{\text{C,V,Y}} * \text{DeratingFactor}_{\text{Y}} * \text{MarginalDistCost}_{\text{C,V,Y,b}}$$

The indices of the parameters in Equation 4-8 include:

- C = Constraint on an element (e.g., pole-mounted transformer, distribution line, etc.) of the distribution system[43]
- V = Voltage level (e.g., primary, and secondary)
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

ΔPeakLoad$_{\text{Y,r}}$ (ΔMW) is the nameplate demand reduction of the project at the retail delivery or connection point (“r”). This input is project specific. A positive value represents a reduction in peak load.

$\text{Loss\%}_{\text{Y,b}\rightarrow\text{r}}$ (%) is the variable loss percent between the bulk system (“b”) and the retail delivery point (“r”). Thus, this reflects the sum of the transmission and distribution system loss percent values, both found in Table A-2. This parameter is used to adjust the $\Delta\text{PeakLoad}_{\text{Y,r}}$ parameter to the bulk system level.

DistCoincidentFactor$_{\text{C,V,Y}}$ (dimensionless) is a project specific input that captures the contribution to the distribution element’s peak relative to the project’s nameplate demand reduction. For example, a nameplate demand reduction of 100 kW on the distribution feeder with a coincidence factor of 0.8 would contribute an 80-kW reduction to peak load on an element of the distribution system.

[42] The one-year assumption is based on an overview of price suppression provided in the New England Regional Avoided Cost Study 2015.
[43] In limited cases where use of system-wide marginal cost values is required, this subscript is not applicable.

Network systems comprise a significant portion of Con Edison's distribution system. When considering DER for relieving overloads on network distribution elements such as a primary feeder or a network transformer, the location of the DER relative to the overloaded element directly affects the percentage contribution of the DER to relieving that overload. As the electrical distance from the DER to the point of need increases, the value of the DER in reducing the specific overload quickly lessens. DER on the network system have diffuse impacts because the power flows in the network move in so many directions.[44]

Radial systems comprise a smaller portion of Con Edison's distribution system. Similarly, when considering DER for relieving overloads on such systems, the location of the DER with respect to the point of need is also of importance. In radial systems, a DER must be located "downstream" of the point of need (relative to the substation) to contribute to resolving the respective overload.

In Con Edison's system, Area Substations and sub-transmission feeders supply the distribution systems such as those mentioned above. When considering a DER (or portfolio of DER) to resolve sub-transmission feeder and Area Substation overloads, DER located anywhere in the respective distribution system would provide load relief benefits that would "roll upstream" to the respective point of need.

$\mathbf{DeratingFactor_{Y}}$ (dimensionless) is a project specific input that is presented here as a generic factor to de-rate the distribution coincident peak load based on the availability of the load during peak hours. For example, a demand response program may only be allowed to dispatch a maximum of 10 events per year, which could limit the availability of the resource during peak hours. Another example is the variability and intermittence (e.g., due to clouds) of a solar array which could limit its peak load reduction contribution on an element of the distribution system.

$\mathbf{MarginalDistCost_{C,V,Y,b}}$ (\$/MW-yr) is the marginal cost of the distribution equipment from which the load is being relieved. It is assumed that the marginal cost of service is based on the bulk system ("b"). If the available marginal cost of service value is based on a different basis, then this parameter must first be converted to represent load at the bulk system prior to using in the equation above. Localized or equipment-specific marginal costs of service should be used in most cases. In limited circumstances use of the system average marginal cost may be acceptable, for example, for evaluation of energy efficiency programs. When localized or equipment-specific marginal costs are within specific cost center(s), the remaining cost centers in the system average may be included. System average marginal cost of service values are provided in Table A-3.

4.2.1.2 General Considerations

Project- and location- specific avoided distribution costs and deferral values should be used whenever possible. Using system average marginal costs to estimate avoided transmission and distribution infrastructure needs may result in significant over- or under-valuation of the benefits or costs. Coincidence and derating factors would be determined by a project-specific engineering study.

Avoided distribution infrastructure benefits for a specific location are realized only if a DER project or portfolio of DER projects meets the engineering requirements for functional equivalence (i.e., DER reliably reduces coincident load to a level that allows the deferral or avoidance of the distribution project. The DSIP identifies specific areas where a distribution upgrade need exists and where DER could potentially provide this benefit.

Use of system average avoided cost assumptions may be required in some situations, such as system-wide programs or tariffs. System average marginal costs for remaining cost centers not included in the

[44] Electric Power Research Institute, *Time and Locational Value of DER: Methods and Applications,* Report No. 3002008410.

project- and location-specific avoided distribution costs may also be included as a benefit. This avoids double counting at the project level cost center, while quantifying all upstream benefits. These system averages by cost center are provided in Table A-3.

The timing of benefits realized from peak load reductions are project and/ or program specific. It is assumed that a peak load reduction impact will produce benefits in the year of the impact. Once the peak load reduction is no longer enough to avoid or defer investment and infrastructure must be built, the benefits should not be recognized from that point forward.

The marginal cost of distribution capacity values provided in Table A-3 include both capital and O&M, which cannot be split into two discrete benefits. Therefore, whenever these system average values are used, care should be taken to avoid double counting of any O&M values included in this benefit and as part of the Avoided O&M benefit described in Section 4.2.2.

4.2.2 Avoided O&M

Avoided O&M includes any benefits incremental to the value captured in the Avoided Distribution Capacity Infrastructure benefit (Section 4.2.1). As discussed above, marginal cost studies include O&M and that O&M is not separately included in this benefit. Therefore, this benefit includes reduced expenses not tied to avoided or deferred distribution system investment from DER. For example, this benefit may capture O&M savings from investments to improve customer service that reduces phone calls to the call center or O&M savings from migrating toward advanced meter functionality reducing meter reading costs. However, at this time, it is expected that the value of this benefit for most DER projects will be zero. For example, DER may reduce equipment loading, which reduces failure rates, but somewhat higher equipment loading may have led to the installation of new equipment with lower O&M costs. Further analysis is required to understand how DER would impact O&M.

4.2.2.1 Benefit Equation, Variables, and Subscripts

Equation 4-9 presents the benefit equation for Avoided O&M Costs:

Equation 4-9. Avoided O&M

$$\text{Benefit}_{Y} = \sum_{AT} \Delta\text{Expenses}_{AT,Y}$$

The indices of the parameters in Equation 4-9 include:

- AT = activity type (e.g., line crews to replace equipment, engineering review of DER interconnection applications, responding to calls received at call centers)
- Y = Year

ΔExpenses$_{AT,Y}$ (Δ\$): Change in O&M expenses due to a project, including an appropriate allocation of administrative and common costs. These costs would increase by inflation, where appropriate.

4.2.2.2 General Considerations

Distribution O&M benefits from DER may be limited to instances where DER can avoid or defer new distribution equipment, a benefit which is already captured in the Avoided Distribution Capacity Infrastructure benefit (Section 4.2.1), where the O&M costs are embedded in the marginal cost of service values. DER interconnections could increase O&M costs, while lower equipment failure rates could decrease these costs. In general, these impacts are difficult to quantify for DER investments and may be trivial in most cases.

Avoided O&M benefits would be quantifiable for some non-DER investments, such as utility investments in DSP capabilities. For example, a utility investment in advanced metering functionality may avoid truck rolls and other costs by collecting meter data remotely.

4.2.3 Distribution Losses

Avoided Distribution Losses are the incremental benefit that is realized when a project causes distribution system loss to change which in turn results in changes to both annual energy use and peak demand. Distribution losses are already accounted for in the LBMP and AGCC when grossing impacts at the project location to the price locations. Because static forecasts of LBMPs and AGCC are used, this benefit will be quantified only in cases where a measure, project, or portfolio alters the distribution system losses percentage (e.g., from 3% to 2.9%).

4.2.3.1 Benefit Equation, Variables, and Subscripts

Equation 4-10 presents the benefit equation for Avoided Distribution Losses:

Equation 4-10. Avoided Distribution Losses

$$\text{Benefit}_{Y+1} = \sum_{Z} \text{SystemEnergy}_{Z,Y+1,b} * \text{LBMP}_{Z,Y+1,b} * \Delta\text{Loss\%}_{Z,Y+1,i\rightarrow r} + \text{SystemDemand}_{Z,Y,b} * \text{AGCC}_{Z,Y,b} * \Delta\text{Loss\%}_{Z,Y,i\rightarrow r}$$

Where,

$$\Delta\text{Loss\%}_{Z,Y,i\rightarrow r} = \text{Loss\%}_{Z,Y,i\rightarrow r,\text{baseline}} - \text{Loss\%}_{Z,Y,i\rightarrow r,\text{post}}$$

The indices[45] of the parameters in Equation 4-10 include:

- Z = NYISO zone (for LBMP: A → K; for AGCC: NYC, LHV, LI, ROS[46])
- Y = Year
- i = Interface Between Transmission and Distribution Systems
- b = Bulk System
- r = Retail Delivery or Connection Point

$\text{SystemEnergy}_{Z,Y,b}$ (MWh) is the system energy purchased in the relevant area of the distribution system (i.e., the portion of the system where losses were impacted by the project) at the retail location by zone. Note that the system energy is used here, rather than the project-specific energy, because this benefit is only quantified when the distribution loss percent value has changed, an event which affects all load in the relevant part of the distribution system.

$\text{LBMP}_{Z,Y,b}$ (\$/MWh) is the LBMP, which is the sum of energy, congestion, and losses components by NYISO zone at the bulk system level ("b"). To determine time-differentiated LBMPs, for example, annual, seasonal, monthly, or hourly, leverage NYISO's hourly LBMP forecast by zone rather than developing an alternative forecast of time-differentiated LBMPs based on using historical data to shape annual zonal averages. The NYISO hourly LBMP forecast is a direct output from the CARIS Phase 2 modeling. It may

[45] In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.
[46] Mapping NYISO localities to NYISO zones: ROS = A-F, LHV = G-I, NYC = J, LI = K.

be necessary to assume that the last year of the LBMPs stay constant in real (inflation adjusted) \$/MWh if the LBMP forecast needs to extend beyond the CARIS planning period.

$\text{SystemDemand}_{Z,Y,b}$ (MW) is the system peak demand for the portion of the retail location on the distribution system(s) (i.e., the portion of the system where losses are impacted by the project) for the relevant NYISO capacity zone. This parameter is grossed up to the bulk system level (i.e., location of the AGCC) based on the $\text{Loss\%}_{Z,b\rightarrow r}$ parameter. Note that the system demand is used in this evaluation, rather than the project-specific demand, because this benefit is only quantified when the system topology is changed resulting in a change in distribution loss percent, an event which affects all load in the relevant part of the distribution system.

$\text{AGCC}_{Z,Y,b}$ (\$/MW-yr) represents the annual AGCCs at the bulk system level ("b") based on forecast of capacity prices for the wholesale market provided by Staff and posted on DMM under Case 14-M-0101. This data can be found in Staff's ICAP Spreadsheet Model in the "AGCC Annual" tab in the "Avoided GCC at Transmission Level" table. This spreadsheet converts "Generator ICAP Prices" to "Avoided GCC at Transmission Level" based on capacity obligations at the forecast of capacity prices for the wholesale market. Note that the AGCC values provided in this spreadsheet are in the units of \$/kW-mo, which must be converted to \$/MW-yr to match the peak load impact in MW. To convert units to \$/MW-yr, the summer and winter \$/kW-mo values are multiplied by six months each, added together, and then multiplied by 1,000.

$\Delta\text{Loss\%}_{Z,Y,i\rightarrow r}$ (Δ%) is the change in the fixed and variable loss percent between the interface between the transmission and distribution systems ("i") and the retail delivery point ("r") resulting from a project that changes the topology of the distribution system. This value would typically be determined in a project-specific engineering study. Two parameters are provided in the equations above: one with a "Y" subscript to represent the current year, and one with a "Y+1" subscript to represent the following year.

$\text{Loss\%}_{Z,Y,i\rightarrow r,\text{baseline}}$ (%) is the baseline fixed and variable loss percent between the interface of the transmission and distribution systems ("i") and the retail delivery point ("r"). Thus, this reflects the distribution loss percent pre-project, which is found in Table A-2.

$\text{Loss\%}_{Z,Y,i\rightarrow r,\text{post}}$ (%) is the post-project fixed and variable loss percent between the interface of the transmission and distribution systems ("i") and the retail delivery point ("r").

4.2.3.2 General Considerations

Distribution losses are already accounted for in the LBMP and AGCC when grossing impacts at the project location to the price locations. Because static forecasts of LBMPs and AGCC are used, this benefit will be quantified only in cases where a measure, project, or portfolio alters the distribution system losses percentage (e.g., from 3% to 2.9%). For most projects, this benefit will be zero unless an engineering study determines otherwise.

The energy and demand impacts are grossed up from retail impacts to transmission system impacts based on losses from the equations above. Impacts are based on system-wide energy and demand, not project-specific, because this benefit is only quantified when the loss percentage is changed which affects all load in the affected area. Note that distribution losses also affect upstream transmission losses. Because losses data is usually available on an annual average basis, the energy and demand impacts should be on an annual average basis as well.

It is assumed that the LBMP component of the avoided losses benefit is accrued in the same year as the impact, and the AGCC component of the benefit is accrued in the following year of the benefit. This is reflected in the equation above with "Y" and "Y+1" subscripts to indicate the time delay of benefits relative to the impacts.

4.3 Reliability/Resiliency Benefits

4.3.1 Net Avoided Restoration Costs

Avoided Restoration Costs accounts for avoided costs of restoring power during outages. For most DER investments this benefit will not be quantified as utilities are required to fix the cause of an outage regardless of whether the DER allows the customer to operate independently of the grid. For some non-DER investments such as automatic feeder switching, distribution automation and enhanced equipment monitoring, the utility may save time and other expenses dispatching restoration crews as a result of having improved visibility into the type and nature of the fault. Storm hardening and other resiliency investments can reduce the number of outage events, resulting in reduced restoration crew hours. Two methodologies to capture the potential value of specific programs or specific projects are identified below. Use of either methodology depends on the type of investment/technology under analysis. Equation 4-11 will generally apply to non-DER investments that allow the utility to save time and other expenses dispatching restoration crews. Equation 4-12 will generally apply to DER investments that are able to provide functionally equivalent reliability as an alternative to the traditional utility investment.

4.3.1.1 Benefit Equation, Variables, and Subscripts

Equation 4-11 presents the benefit equation for Net Avoided Restoration Costs associated with non-DER investments:

Equation 4-11. Net Avoided Restoration Costs

$$\text{Benefit}_\text{Y} = -\Delta\text{CrewTime}_\text{Y} * \text{CrewCost}_\text{Y} + \Delta\text{Expenses}_\text{Y}$$

Where,

$$\Delta\text{CrewTime}_\text{Y} = \#\text{Interruptions}_{\text{base,Y}} * (\text{CAIDI}_{\text{base,Y}} - \text{CAIDI}_{\text{post,Y}} * (1 - \%\text{ChangeSAIFI}_\text{Y}))$$

$$\%\text{ChangeSAIFI}_\text{Y} = \frac{\text{SAIFI}_{\text{base,Y}} - \text{SAIFI}_{\text{post,Y}}}{\text{SAIFI}_{\text{base,Y}}}$$

SAIFI, CAIDI and SAIDI values could be utilized at the system level for non-DER projects/programs that are applicable across a total system basis. More targeted data should be utilized for localized and geographic specific projects that exhibit more localized impacts. Other reliability metrics will need to be developed to more suitably quantify reliability or resiliency benefits and costs associated with localized projects or programs. Once developed, the localized restoration cost metric will be applied and included in this handbook.

There is no subscript to represent the type of outage in Equation 4-11 because it assumes an average restoration crew cost that does not change based on the type of outage. The ability to reduce outages would be dependent on the outage type.

$\boldsymbol{\Delta\text{CrewTime}_\text{Y}}$ **(∆hours/yr)** is the change in crew time to restore outages based on an impact on frequency and duration of outages. This data is project and/or program specific. A positive value represents a reduction in crew time

$\mathbf{CrewCost_Y}$ **($/hr)** is the average hourly outage restoration crew cost for activities associated with the project under consideration

$\mathbf{\Delta Expenses_Y}$ **(Δ$)** are the average expenses (e.g., equipment replacement) associated with outage restoration.

$\mathbf{\#Interruptions_{base,Y}}$ **(int/yr)** are the baseline (i.e., pre-project) number of sustained interruptions per year, excluding major storms. The system-wide five-year average number of interruptions excluding major storms is available from the annual Electric Service Reliability Reports.

$\mathbf{CAIDI_{base,Y}}$ **(hr/int)** is the baseline (i.e., pre-project) Customer Average Interruption Duration Index. It represents the average time to restore service, excluding major storms. The system-wide five-year average CAIDI is available from the annual Electric Service Reliability Reports. Generally, this parameter is a system-wide value. In localized project/program specific cases, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

$\mathbf{CAIDI_{post,Y}}$ **(hr/int)** is the post-project Customer Average Interruption Duration Index. It represents the average time to restore service. Determining this parameter would require development of a distribution level model and a respective engineering study to quantify appropriately.

$\%\mathbf{ChangeSAIFI_Y}$ **(Δ%)** is the percent change in System Average Interruption Frequency Index. It represents the percent change in the average number of times that a customer experiences an outage per year.

$\mathbf{SAIFI_{base,Y}}$ **(int/cust/yr)** is the baseline (i.e., pre-project) System Average Interruption Frequency Index. It represents the average number of times that a customer experiences an outage per year, excluding major storms. The baseline system-wide value is a five-year average. It is available from the annual Electric Service Reliability Reports. Generally, this parameter is system-wide value. In localized project/program specific cases, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

$\mathbf{SAIFI_{post,Y}}$ **(int/cust/yr)** is the post-project System Average Interruption Frequency Index. It represents the average number of times that a customer experiences an outage per year in the post-project scenario. Determining this parameter would require development of a distribution level model and a respective engineering study to quantify appropriately.

Equation 4-12. Net Avoided Restoration Costs

$$\mathrm{Benefit_Y} = \mathrm{MarginalCost_{R,Y}}$$

The indices of the parameters in Equation 4-12 are applicable to DER installations and include:

- R = Reliability constraint on an element (e.g., pole-mounted transformer, distribution line, etc.) of T&D system
- Y = Year

$\mathbf{MarginalDistCost_{R,Y}}$ **($/yr):** Marginal cost of the reliability investment. Because this value is project- and location- specific, a system average value is not applicable.

This benefit only applies for an individual project or portfolio of DER which is able to provide functionally equivalent reliability as compared to the reliability provided by the traditional distribution reliability investment that would have otherwise been installed/built; if the DER does not defer or avoid a traditional reliability investment, this benefit does not apply. When an individual or portfolio of DER can defer a distribution reliability investment, the value of the avoided restoration cost is already reflected in the Avoided Distribution Capacity Infrastructure benefit calculation.

4.3.1.2 General Considerations

The impact on SAIFI or CAIDI is due to the implementation of the project relative to a baseline rather than outside factors such as weather. The changes to these parameters should consider the appropriate context of the project including the types of outage events and how the project may or may not address each type of event to inform the magnitude of impact. For example, whether the project impacts one feeder or a portion of the distribution system. The baseline values should match the portion of the system impacted.

In addition to being project-specific, the calculation of avoided restoration costs is dependent on projection of the impact of specific investments related to the facilitation of actual system restoration and the respective costs. It is unrealistic to expect that DER investments will limit or replace the need to repair field damage to the system, and as such, system restoration benefits attributable to DER type investments are unlikely. Application of this benefit would be considered only for investments with validated reliability results.

4.3.2 Net Avoided Outage Costs

Avoided Outage Costs accounts for customer outage costs due to a reduction in frequency and duration of outages, then multiplying that expected change by an estimated outage cost. The quantification of this benefit is highly dependent on the type and size of affected customers.

4.3.2.1 Benefit Equation, Variables, and Subscripts

Equation 4-13 presents the benefit equation for Net Avoided Outage Costs:

Equation 4-13. Net Avoided Outage Costs

$$\mathrm{Benefit}_{\mathrm{Y}} = \sum_{C} \text{ValueOfService}_{C,Y,r} * \text{AverageDemand}_{C,Y,r} * \Delta\mathrm{SAIDI}_{\mathrm{Y}}$$

Where,

$$\Delta\mathrm{SAIDI}_{\mathrm{Y}} = \mathrm{SAIFI}_{\mathrm{base,Y}} * \mathrm{CAIDI}_{\mathrm{base,Y}} - \mathrm{SAIFI}_{\mathrm{post,Y}} * \mathrm{CAIDI}_{\mathrm{post,Y}}$$

The indices of the parameters in Equation 4-13 include:

- C = Customer class (e.g., residential, small C&I, large C&I) – BCA should use customer-specific values if available.
- Y = Year
- r = Retail Delivery or Connection Point

ValueOfService$_{C,Y,r}$ ($/kWh) is the value of electricity service to customers, by customer class, in dollars per unserved kWh at the retail delivery point. The value(s) should be determined based on the customers' willingness to pay for reliability. If location-, customer class- or customer-specific values are not available, these values should default to the retail rate of electricity by customer class.

AvgDemand$_{C,Y,r}$ (kW) is the average demand in kW at the retail delivery or connection point ("r") that would otherwise be interrupted during outages but can remain electrified due to DER equipment and/or utility infrastructure. This would need to be identified by customer class, or by customer, if available. If the timing of outages cannot be predicted, this parameter can be calculated by dividing the annual energy consumption by 8,760 hours per year.

$\Delta\mathbf{SAIDI_Y}$ (Δhr/cust/yr): is the change in System Average Interruption Duration Index due to the project. The impact on SAIDI can be determined based on the impact on CAIDI and SAIFI.[47] Baseline system average reliability metrics are available in the Company's annual Electric Service Reliability Reports. A positive value represents a reduction in SAIDI.

$\mathbf{SAIFI_{post,Y}}$ (int/cust/yr) is the post-project System Average Interruption Frequency Index and represents the average number of times that a customer experiences an outage per year in the post-project case. Determining this parameter requires development of a distribution level model and a respective engineering study to quantify appropriately.

$\mathbf{CAIDI_{post,Y}}$ (hr/int) is the post-project Customer Average Interruption Duration Index and represents the impact of a project on the average time to restore service in the post-project case. Determining this parameter requires development of a distribution level model and a respective engineering study to quantify appropriately.

$\mathbf{SAIFI_{base,Y}}$ (int/cust/yr) is the baseline (i.e., pre-project) System Average Interruption Frequency Index. It represents the average number of times that a customer experiences an outage per year, excluding major storms. The baseline system-wide value is a five-year average that is available from the annual Electric Service Reliability Reports. This parameter is not necessarily a system-wide value. Rather, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

$\mathbf{CAIDI_{base,Y}}$ (hr/int) is the baseline (i.e., pre-project) Customer Average Interruption Duration Index. It represents the impact of a project on the average time to restore service, excluding major storms. The baseline system-wide is a five-year average that is available from the annual Electric Service Reliability Reports. This parameter is not necessarily a system-wide value. Rather, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

4.3.2.2 General Considerations

The value of the avoided outage cost benefit is customer-specific; the customer class should match or be consolidated properly between the utility and the study area to ensure that the value of reliability matches, what the customer would be willing to pay.

For this version of the BCA Handbook, the outage cost can be estimated by assuming that the customer would be willing to pay the same retail rate they pay for electricity, to avoid an outage. The full retail rate value can be found in the utility's latest tariff by customer class.

Currently, the Standard Interconnection Requirements do not allow for islanding, and therefore limit this configuration to a DER that meets the needs of a customer during an outage. Therefore, there are limited

[47] SAIDI = SAIFI * CAIDI.

instances where DER allows the customer to supply local load in a blackout and resulting benefits would then be limited to that load picked up by DER.

4.4 External Benefits

4.4.1 Net Avoided CO_2

Net Avoided CO_2 accounts for avoided CO_2 due to a reduction in system load levels[48] or the increase of CO_2 from onsite generation. To value the benefits associated with avoided CO2 emissions, utilities shall rely on the costs to comply with New York's Clean Energy Standard (CES), valued as the resulting price per MWh of a Renewable Energy Certificate (REC) from the most recently completed NYSERDA RECs solicitation.

4.4.1.1 Benefit Equation, Variables, and Subscripts

Equation 4-14 presents the benefit equation for Net Avoided CO_2:

Equation 4-14. Net Avoided CO_2

Using the cost to comply with New York's CES[49]:

$$\mathrm{Benefit_Y} = \mathrm{CESCost} * \left(\frac{\Delta \mathrm{Energy_{Y,r}}}{1 - \mathrm{Loss\%_{Y,b \to r}}} + \Delta \mathrm{Energy_{TransLosses,Y}} + \Delta \mathrm{Energy_{DistLosses,Y}} \right)$$

The indices of the parameters in Equation 4-14 include:

- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

CESCost ($/MWh) is the cost of compliance with New York's Clean Energy Standard (CES) valued as the resulting price per MWh of a Renewable Energy Certificate (REC) from the most recently completed NYSERDA RECs solicitation.

$\boldsymbol{\Delta \mathrm{Energy_{Y,r}}}$ **(ΔMWh)** is the change in energy purchased at the retail delivery or connection point ("r") as a result of the project. This parameter considers the energy impact at the project location, which is then grossed up to the bulk system level based on the $Loss\%_{b \to r}$ parameter. A positive value represents a reduction in energy.

$\boldsymbol{\mathrm{Loss\%_{Y,b \to r}}}$ **(%)** is the variable loss percent from the bulk system level ("b") to the retail delivery or connection point ("r"). These values can be found in Table A-2.

$\boldsymbol{\Delta \mathrm{Energy_{TransLosses,Y}}}$ **(ΔMWh)** represents the change in electricity lost on the transmission system due to the Avoided Transmission Losses benefit. Refer to Section 4.1.4 for more details. In most cases, unless

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[48] The Avoided CO_2 benefit considers the change in energy as a result of the project by including the change in energy identified in the Avoided LBMP, Avoided Transmission Losses, and Avoided Distribution Losses benefits.

[49] This construct assumes there are no onsite emissions.

the transmission system loss percent is altered due to a project or portfolio, this parameter will be zero. A positive value represents a reduction in energy lost in transmission system losses.

$\Delta\mathbf{Energy}_{\mathbf{DistLosses,Y}}$ **(ΔMWh)** represents the change in energy lost on the distribution system due to the Avoided Distribution Losses benefit. Refer to Section 4.2.3 for more details. In most cases, unless the distribution system loss percent is altered due to a project or portfolio, this parameter will be zero. A positive value represents a reduction in energy lost in distribution system losses.

4.4.1.2 General Considerations

The energy impact is project-specific and should be linked to the impacts determined in the Avoided LBMP benefit. The LBMP impacts due to the Avoided Transmission Losses and Avoided Distribution Losses benefits also need to be accounted for when determining the total change in LBMP due to a project. It is assumed that the benefit value due to an impact on emissions is accrued in the same year as the impact.

For electric demand-side management programs, a multiplier will be applied to the seasonal net avoided CO2 benefit calculations based on the season (winter or summer) that the program is active and, for winter net avoided CO2 benefit calculations, the number of peak days active.

The *BCA Order* indicates “utilities shall rely on the costs to comply with New York’s Clean Energy Standard once those costs are known.”[50]

4.4.2 Net Avoided SO_2 and NO_x

Net Avoided SO_2 and NO_x includes the incremental value of avoided or added emissions. The LBMP already includes the cost of pollutants (i.e., SO_2 and NO_x) as an “internalized” cost from the Cap & Trade programs. Emitting customer-sited generation <25 MW will be included in this benefit since the generators do not participate in the Cap & Trade programs.

4.4.2.1 Benefit Equation, Variables, and Subscripts

Equation 4-15 presents the benefit equation for Net Avoided SO_2 and NO_x:

Equation 4-15. Net Avoided SO_2 and NO_x

$$\mathrm{Benefit}_{\mathrm{Y}} = \sum_{\mathrm{p}} \mathrm{OnsiteEmissionsFlag}_{\mathrm{Y}} * \mathrm{OnsiteEnergy}_{\mathrm{Y,r}} * \mathrm{PollutantIntensity}_{\mathrm{p,Y}} * \mathrm{SocialCostPollutant}_{\mathrm{p,Y}}$$

The indices of the parameters in Equation 4-15 include:

- p = Pollutant (SO_2, NO_x)
- Y = Year
- r = Retail Delivery or Connection Point

$\mathbf{OnsiteEmissionsFlag}_{\mathbf{Y}}$ is a binary (i.e., 0 or 1) parameter, where a value of 1 indicates that customer-sited pollutant-emitting generation <25 MW will be included in the analysis as a result of the project.

$\mathbf{OnsiteEnergy}_{\mathbf{Y,r}}$ **(ΔMWh)** is the energy produced by customer-sited pollutant-emitting generation.

[50] REV Proceeding, BCA Order, Appendix C, p. 16.

$PollutantIntensity_{p,Y}$ (ton/MWh) is average pollutant emissions rate of customer-sited pollutant-emitting generation. This is a project-specific input.

$SocialCostPollutant_{p,Y}$ ($/ton) is an estimate of the monetized damages to society associated with an incremental increase in pollutant emissions in a given year. The allowance prices are provided in CARIS Phase 2

4.4.2.2 General Considerations

LBMPs already include the cost of pollutants (i.e., SO_2 and NO_x) as an "internalized" cost from the Cap & Trade programs. Emitting customer-sited generation <25 MW will be included in this benefit since the generators do not participate in the Cap & Trade programs. This would be a benefit to the extent that the DER emits less than NYISO generation, and a negative benefit for the DER if it has a higher emissions rate than NYSO generation or emissions–free DER.

Two values are provided in CARIS for NO_x costs: "Annual NO_x" and "Ozone NO_x." Annual NO_x prices are used October through May; Ozone NO_x prices May through September. The breakdown of energy in these two time periods must be accounted for and applied to the appropriate NO_x cost.

It is assumed that the benefit value due to an impact on emissions is accrued in the same year as the impact.

4.4.3 Avoided Water Impact

A suggested methodology for determining this benefit is not included in this version of the Handbook. This impact would be assessed qualitatively in the SCT.

4.4.4 Avoided Land Impact

A suggested methodology for determining this benefit is not included in this version of the Handbook. This impact would be assessed qualitatively in the SCT.

4.4.5 Net Non-Energy Benefits Related to Utility or Grid Operations

A suggested methodology for determining this benefit is not included in this version of the Handbook. This impact would be assessed qualitatively or if possible estimated quantitatively. It is necessary to identify which cost-effectiveness test should include the specific benefit or cost as it may apply to the SCT, UCT and/or RIM.

4.5 Costs Analysis

4.5.1 Program Administration Costs

Program Administration Costs includes the cost to administer and measure the effect of required program administration performed and funded by utilities or other parties. This may include the cost of incentives, measurement and verification, and other program administration costs to start, and maintain a specific program. The reduced taxes and rebates to support certain investments increase non-participant costs.

4.5.1.1 Benefit Equation, Variables, and Subscripts

Equation 4-16 presents the cost equation for Program Administration Costs:

Equation 4-16. Program Administration Costs

$$\text{Cost}_Y = \sum_M \Delta\text{ProgramAdminCost}_{M,Y}$$

The indices of the parameters in Equation 4-16 include:

- M = Measure
- Y = Year

ΔProgramAdminCost$_{M,Y}$ is the change in Program Administration Costs, which may include one-time or annual incentives such as rebates, program administration costs, measurement and verification, state incentives, and other costs. These costs would increase by inflation, where appropriate.

4.5.1.2 General Considerations

Program Administration Costs are program- and project-specific. As a result, it is not possible to estimate the Project Administration Cost in advance without a clear understanding of the program and project details. Program-specific details that are necessary to calculate the cost impact can include, but are not limited to, the scale of the activity, the types of participating technologies, and locational details. Sub-categories that could fall under Program Administration Costs include, but are not limited to, programmatic measurement & verification costs, utility-specific rebates and/or incentives, and costs of market interventions (e.g., state and federal incentives).

4.5.2 Added Ancillary Service Costs

Added Ancillary Service Costs occur when DER causes additional ancillary service costs on the system. These costs shall be considered and monetized in a similar manner to the method described in the 4.1.5 Avoided Ancillary Services (Spinning Reserves, and Frequency Regulation).

4.5.3 Incremental Transmission & Distribution and DSP Costs

Additional incremental T&D Costs are caused by projects that contribute to the utility's need to build additional infrastructure.

Additional T&D infrastructure costs shall be considered and monetized in a similar manner to the method described in Section 4.1.3 Avoided Transmission Capacity Infrastructure and Related O&M.
The potential for incremental T&D costs depends on the interconnection location, type of DER, and penetration of other DER in the area. As a result, it is not possible to estimate the Additional T&D infrastructure cost in advance without a clear understanding of this information.

Depending on the nature of a specific DER project, the incremental costs could be borne by the interconnecting facility or utility customers. For instance, a utility may need to make further investment in their T&D infrastructure such as expanding system capacity, implementing more sophisticated control functionalities, or enhancing protection to ensure seamless grid integration of new DER assets.

In some situations, enhanced capabilities of a DSP would be required. These incremental costs would be identified and included within this cost.

4.5.4 Participant DER Cost

Participant DER Cost is money required to fund programs or measures that is not provided by the utility. It includes accounts for the equipment and participation costs assumed by DER providers or participants which need to be considered when evaluating the societal costs of a project or program. The Participant

DER Cost is equal to the full incremental DER Cost above the baseline alternative net of program rebates, and incentives that are included as part of Program Administration Costs. To the extend there is no assumed baseline, the full DER Cost net of program rebates and incentives will be used. The Participant DER Cost may include land use costs, such as lease costs. In the case of projects sited on land currently owned by the utility, the land will be valued through an appraisal process.[51]

The full DER Cost includes the installed cost of the device or system, as well as any ongoing operations and maintenance expenses to provide the solution. Installed costs include the capital cost of the equipment as well as labor and materials for the installation. Operating costs include ongoing maintenance expenses. For projects where only a portion of the costs can be attributed to the establishment of a DER, only that portion of the total project cost should be considered as the Full DER Cost. This practice is generally appropriate for projects where the non-participation scenario carries some baseline cost, such as replacing an appliance with a high efficiency alternative at the time of failure. In such a scenario, only the incremental costs above the baseline appliance should be considered as the Full DER Cost.

This section provides four examples of DER technologies with illustrative cost information based on assumptions that will ultimately vary given the facts and circumstances specific to each DER application:

- Solar PV – residential (4 kW)
- Combined Heat and Power (CHP) – reciprocal engine (100 kW)
- Demand Response (DR) – controllable thermostat
- Energy Efficiency (EE) – commercial lighting

All cost numbers presented herein should be considered illustrative estimates only. These represent the full costs of the DER and do not account for or net out any rebates or incentives. Actual Participant DER costs will vary by project based upon factors including:

- **Make and model:** The DER owner typically has an array of products to choose from, each of which has different combinations of cost and efficiency.
- **Type of installation:** The location of where the DER would be installed influences the capital costs, for example, ground-mounted or roof-mounted PV
- **Geographic location:** Labor rates, property taxes, and other factors vary across utility service areas and across the State
- **Available rebates and incentives**: Include federal, state, and/or utility funding.

The Commission noted in its *Order Adopting Regulatory Policy Framework and Implementation Plan* (REV Track One Order) that the approach employed to obtain DER will evolve over time: "The modernization of New York's electric system will involve a variety of products and services that will be developed and transacted through market initiatives. Products, rules, and entrants will develop in the market over time, and markets will value the attributes and capabilities of all types of technologies. As DSP capabilities evolve, procurement of DER attributes will develop as well, from a near-term approach based on RFPs and load modifying tariffs, towards a potentially more sophisticated auction approach."[52]

[51] Joint Utilities Approach to Unused Land Inventory and Valuation, April 2020.
[52] REV Proceeding, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015) (Track One Order), p. 33.

The acquisition of most DER in the near term will be through competitive solicitations and standing tariffs. The BCA Order requires a fact specific basis for quantifying costs that are considered in any SCT evaluation.[53] Company competitive solicitations for DER will require the disclosure of costs by the bidders, including but not limited to capital, installation, marketing, administrative, fixed and variable O&M, lost opportunity and/or behavioral incentive costs. The Company will use the submitted costs in the project/program/portfolio BCA evaluation. Additionally, the Company will employ this information to develop and update its technology specific benchmark costs as they evolve over time.

For illustrative purposes, examples for a small subset of DER technologies are provided below.

4.5.4.1 Solar PV Example

The solar PV used in this example is a 4 kW-AC residential rooftop system which is connected to the local distribution system through the customer's meter. All cost parameters in Table 4-1 for the intermittent solar PV example are derived based on information provided in the E3's *The Benefits and Costs of Net Energy Metering in New York* (E3 Report).[54] In this report, E3 used cost data provided by NYSERDA based on solar PV systems that were installed in New York from 2003 to 2015. This is just one example of evaluating the potential cost of solar PV technology. The Company would need to incorporate service territory specific information when developing its technology benchmarks. For a project-specific cost analysis, actual estimated project costs would be used.

Table 4-1. Solar PV Example Cost Parameters

Parameter	Cost
Installed Cost (2015$/kW-AC)[55]	4,430
Fixed Operating Cost ($/kW)	15

Note: These costs would change as DER project-specific data is considered.

1. **Capital and Installation Cost:** Based on the E3 Report's estimate of 2015 residential PV panel installed cost. For solar the $/kW cost usually includes both the cost of the technology and installation cost, which is the case in this example. Costs could be lower or higher depending on the size of project, installation complexity and location. This example assumes a 4-kW residential system for an average system in New York. This cost is per kW of nameplate AC capacity. AC capacity is calculated from DC capacity using a factor of 1.1 DC:AC as provided in the E3 Report.
2. **Fixed Operating Cost:** E3's estimate of O&M for a residential PV panel in 2015. This estimate is applied to all New York electric utilities in the NYSERDA paper.

4.5.4.2 CHP Example

The CHP system used in this example is a 100-kW capacity natural gas-fired engine unit sized for commercial thermal load following applications. For this illustration cost parameter values were obtained from the EPA's *Catalog of CHP Technologies*[56] for this baseload CHP example based on estimations of representative system costs. There are many site-specific factors that can affect cost parameters that are

[53] REV Proceeding, BCA Order, Appendix C, p. 18.
[54] E3 [Energy + Environmental Economics], prepared for New York State Research and Development Authority and New York State Department of Public Service, *The Benefits and Costs of Net Energy Metering in New York;* (E3 Report) (December 11, 2015) Case 15-E-0703, *In the Matter of Performing a Study on the Economic and Environmental Benefits and Costs of Net Metering Pursuant to Public Service Law Sec 66-n*, Letter to Secretary Burgess from Deputy Markets and Innovation Weiner (dated December 17, 2015).
[55] This cost is per kW of nameplate AC capacity. AC capacity is calculated from DC capacity using a factor of 1.1 DC:AC as provided in the E3 Report.
[56] United States Environmental Protection Agency and Combined Heat and Power Partnership, *Catalog of CHP Technologies* (EPA Catalog of CHP Technologies): https://www.epa.gov/chp/chp-technologies.

not examined in this example including: property tax, local permitting, gas and electric interconnection costs, local emissions constraints and possible structural requirements. Natural gas costs would need to be considered for the natural gas fired CHP system. All of these elements would need to be reviewed and incorporated to develop the Company's service territory technology specific benchmarks.

Table 4-2. CHP Example Cost Parameters

Parameter	Cost
Installed Capital Cost ($/kW)	3,000
Variable Operating Cost ($/kWh)	0.025

Note: This illustration would change as projects and locations are considered.

- **Capital and Installation Cost:** EPA's estimate of a reciprocating engine CHP system capital cost. This includes of the project development costs associated with the system including equipment, labor and process capital.[57]
- **Variable:** EPA's estimate of a 100-kW reciprocating engine CHP system's non-fuel O&M costs.[58]

4.5.4.3 DR Example

The system dispatchable DR technology described herein is a programmable and controllable thermostat in a residence with central air conditioning that is participating in a direct load control program. The capital cost is based on an average of Wi-Fi enabled controllable thermostats from Nest, Ecobee, and Honeywell. The Participant DER Cost in this instance would be the example Capital and Installation Cost listed below net of baseline thermostat technology costs and any rebates or incentives in order to calculate the incremental DER Participant Cost. This approach is applied here as there are alternative thermostats on the market that serve the basic functions. The Company would need to incorporate its service territory specific information when developing its DR technology benchmarks.

Table 4-3. DR Example Cost Parameters

Parameter	Cost
Capital Cost ($/Unit)	$233
Installation Cost ($/Unit)	$140

- Note: This illustration would change as projects and locations are considered.

- **Capital and Installation Costs:** These costs differ by thermostat model and capabilities, and as such should be considered representative. The installation costs estimates represent a New York system, but will vary substantially depending on the program nature. The final DER Participant Costs used in a SCT analysis would need to be net of the baseline thermostat costs and any available incentives or rebates.
- **Operating Costs:** Assumed to be $0 for the DR asset participant based on comparison with the alternative technology.

4.5.4.4 EE Example

The energy efficient lighting used in this example is indoor installation of tubular LEDs in a commercial office setting.

[57] EPA Catalog of CHP Technologies, pp. 2-15.
[58] EPA Catalog of CHP Technologies, pp. 2-17.

Table 4-4. EE Example Cost Parameters

Parameter	Cost
Installed Capital Cost ($/Unit)	$30

Note: This illustration would change as projects and locations are considered.

- **Installed Capital Cost:** Based on Navigant Consulting's review of manufacturer information and energy efficiency evaluation reports. The final Installed Capital Cost would need to be the net of baseline lighting costs and any available incentives or rebates. The Company would need to incorporate its service territory specific information when developing its EE technology benchmarks.

4.5.5 Lost Utility Revenue

Lost Utility Revenue includes the distribution and other non-by-passable revenues that are shifted on to non-participating customers due to the presence of revenue decoupling mechanisms, in which sales-related revenue shortfalls due to a decrease in electricity sales or demand is recovered by marginally increasing the rate of electricity sales or demand to non-participating customers.

Lost utility revenue is not included in the SCT and UCT as the reduced participant revenues are offset by the increased non-participant revenues. Therefore, this cost is only included in the RIM. As DER reduces utility sales and the associated revenues, a revenue decoupling mechanism enables the utility to be made whole by recovering these lost revenues from other customers.

The impact to non-participating customers would be estimated by evaluating the type of DER and the tariffs applicable to the affected customers.

4.5.6 Shareholder Incentives

Shareholder Incentives include the annual costs to customers of utility shareholder incentives that are tied to the projects or programs being evaluated.

Shareholder incentives are project or program specific and should be evaluated as such.

4.5.7 Net Non-Energy Costs

A suggested methodology for determining this benefit is not included in this version of the Handbook. In cases where non-energy impacts are attributable to the specific project or program, they may be assessed qualitatively. Net Non-Energy Costs may be applicable to any of the cost-effectiveness tests defined in the BCA Order depending on the specific project and non-energy impact.

5. CHARACTERIZATION OF DER PROFILES

This section discusses the characterization of DER using several examples and presents the type of information necessary to assess associated benefits. Four *DER categories* are defined to provide a useful context, and specific example technologies within each category are selected for examination. The categories are *intermittent*, *baseload*, *dispatchable*, and *load reduction*. There are numerous potential examples of individual DER within each category, varying by technology, size, location, customer application, and other factors. A single example DER was selected in each of the four categories to illustrate specific BCA values, as shown in Table 5-1 below. These four examples cover a useful, illustrative range of impacts that DER can have on the various benefit and cost categories in the BCA Handbook.

Table 5-1. DER Categories and Examples Profiled

DER Category	DER Example Technology
Intermittent	Solar PV
Baseload	CHP
Dispatchable	Controllable Thermostat
Load Reduction	Energy Efficient Lighting

The DER technologies selected as examples are shown in Table 5-2. Each DER technology has unique operating characteristics that allow it to accrue some benefits and costs but not others. In some cases, the ability of a DER to provide certain benefits and incur certain costs will be driven by the operational objective of the specific DER, not the intrinsic characteristics of the technology itself. For example, DR technology in one situation may be operated to reduce the NYISO peak, which may or may not coincide with a distribution feeder peak where it is installed. Another DR technology may be operated to provide support for a distribution NWA, in which the distribution feeder or substation may not have a peak load that coincides with the NYISO peak. Thus, the operational objectives of the DR technology would result in different estimates of benefits and costs depending on this operational objective. Key attributes of the example DER technologies are provided in Table 5-2.

Table 5-2. Key Attributes of Selected DER Technologies

Resource	Attributes
Photovoltaic (PV)	PV is an intermittent resource with energy output determined by solar irradiance. The directional orientation and vertical angle of PV panels are important considerations for determining energy output and thus the corresponding coincidence factors with system-wide or local power delivery. PV energy output may also degrade over time.
Combined Heat and Power (CHP)	CHP is a resource typically sized to meet a customer's thermal energy requirements, but which also provides electrical energy. The specific customer's characteristics determine the ability of CHP to contribute to various benefit and cost categories.
Energy Efficiency (EE)	EE reduces the energy consumption for delivery of a particular service (use) without degrading or reducing the level of service delivered.
Demand Response (DR)	DR reduces energy demand for a particular service (use) during specific hours of the day—typically peak demand hours—without reducing the service to an unacceptable level. DR is typically available only for limited hours in a year (e.g., <100 hrs). The operational objective of the DR determines how it may contribute to various benefit and cost categories.

Each example DER can enable a different set of benefits and incurs a different set of costs, as illustrated in Table 5-3.

Table 5-3. General Applicability for Each DER to Contribute to Each Benefit and Cost

#	Benefit/Cost	PV	CHP	DR	EE
	Benefits				
1	Avoided Generation Capacity Costs	●	●	●	●
2	Avoided LBMP	●	●	●	●
3	Avoided Transmission Capacity Infrastructure	◒	◒	◒	◒
4	Avoided Transmission Losses	○	○	○	○
5	Avoided Ancillary Services	○	○	○	○
6	Wholesale Market Price Impacts	○	○	○	○
7	Avoided Distribution Capacity Infrastructure	◒	◒	◒	◒
8	Avoided O&M	○	○	○	○
9	Avoided Distribution Losses	○	○	○	○
10	Net Avoided Restoration Costs	○	○	○	○
11	Net Avoided Outage Costs	○	◒	○	○
12	Net Avoided CO_2	●	●	●	●
13	Net Avoided SO_2 and NO_x	●	●	●	●
14	Avoided Water Impacts	○	○	○	○
15	Avoided Land Impacts	○	○	○	○
16	Net Non-Energy Benefits	○	○	○	○
	Costs				
17	Program Administration Costs	●	●	●	●
18	Added Ancillary Service Costs	○	○	○	○
19	Incremental T&D and DSP Costs	◒	◒	◒	○
20	Participant DER Cost	●	●	●	●
21	Lost Utility Revenue	●	●	●	●
22	Shareholder Incentives	●	●	●	●
23	Net Non-Energy Costs	○	○	○	○

Note: This is general applicability and project-specific applications may vary.

● Generally applicable ◒ May be applicable ○ Limited or no applicability

As described in Section 4, each quantifiable benefit typically has two types of parameters. The defined benefits established to monetize the value are generally unaffected by the DER being analyzed in the BCA (e.g., AGCC in $ per MW-yr), however key parameters related to the magnitude of underlying benefit and may vary by type of DER (e.g., system coincidence factor). In other words, the amount of the underlying value captured by the DER resource is driven by the key parameters. Table 5-4 identifies the parameters which are necessary to characterize DER benefits. As described in Section 4, several benefits potentially applicable to DER require further investigation and project-specific information before their impacts can be incorporated into a BCA (e.g., Avoided O&M, Net Avoided Restoration Costs and Net Avoided Outage Costs, and Avoided Ancillary Services).

Table 5-4. Key Parameter for Quantifying How DER May Contribute to Each Benefit

#	Benefit	Key Parameter
1	Avoided Generation Capacity Costs	**SystemCoincidenceFactor**
2	Avoided LBMP	**ΔEnergy (time-differentiated)**
3	Avoided Transmission Capacity Infrastructure	**TransCoincidenceFactor**
4	Avoided Transmission Losses	Limited or no applicability
5	Avoided Ancillary Services	Limited or no applicability
6	Wholesale Market Price Impacts	**ΔEnergy (annual)** **ΔAGCC**
7	Avoided Distribution Capacity Infrastructure	**DistCoincidenceFactor**
8	Avoided O&M	Limited or no applicability
9	Avoided Distribution Losses	Limited or no applicability
10	Net Avoided Restoration Costs	Limited or no applicability
11	Net Avoided Outage Costs	Limited or no applicability[59]
12	Net Avoided CO_2	**CO_2Intensity** (limited to CHP)
13	Net Avoided SO_2 and NO_x	**PollutantIntensity** (limited to CHP)
14	Avoided Water Impacts	Limited or no applicability
15	Avoided Land Impacts	Limited or no applicability
16	Net Non-Energy Benefits	Limited or no applicability

Table 5-5 further describes the key parameters identified in Table 5-4.

[59] A CHP system may be able to provide a Net Avoided Outage Costs benefit in certain system configurations.

Table 5-5. Key parameters

Key Parameter	Description
Bulk System Coincidence Factor	Necessary to calculate the Avoided Generation Capacity Costs benefit.[60] It captures a project's or program's contribution to reducing bulk system peak demand relative to its expected maximum demand reduction capability
Transmission Coincidence Factor[61]	Necessary to calculate the Avoided Transmission Capacity Infrastructure benefit. It quantifies a project's contribution to reducing a transmission system element's peak demand relative to the project's expected maximum demand reduction capability. This would be evaluated on localized basis in most cases, but in some instances an assessment of coincidence with a system coincidence factor would be appropriate.
Distribution Coincidence Factor	Distribution coincidence factor is required to calculate the Avoided Distribution Capacity Infrastructure benefit. It captures the contribution to the distribution element's peak relative to the project's expected maximum demand reduction capability. This would be evaluated on localized basis in most cases, but in some instances an assessment of coincidence with a system coincidence factor would be appropriate.
CO_2 Intensity	CO_2 intensity is required to calculate the Net Avoided CO_2 benefit. This parameter is dependent on the type of DER being evaluated – emission-free or emission-generating. It is the average CO_2 emission rate of customer-sited pollutant-emitting generation. This is a project-specific input based on the type of onsite generation.
Pollutant Intensity	Pollutant intensity is required to calculate the Net Avoided SO_2 and NO_X benefit. This parameter is dependent on the type of DER being evaluated – emission-free or emission-generating. It is the average SO_2 and/or NO_X emission rate of customer-sited pollutant-emitting generation. This is a project-specific input based on the type of onsite generation.
ΔEnergy (time-differentiated)	This parameter measures the change in bulk system energy consumed as a result of specific DER project implementation. This value is reliant on project-specific details including location. The ΔEnergy is dependent on the type of DER (e.g., *intermittent* vs. *baseload*), and how the DER would be operated (e.g., load reduction vs. energy conservation vs. backup generation). Thus, the ΔEnergy is time-differentiated. It may be appropriate to use an annual average value for some DER, while for others it may be more appropriate to use an average on-peak hours of operation, or even hourly operation. In each case the corresponding LBMP data would be required to value the benefit. The examples provided herein discuss potential approaches to consider time-differentiation by DER type.[62]

5.1 Coincidence Factors

Coincidence factors for DER are an important part of the benefit calculations and can be estimated in a variety of ways. What follows is a general approach for calculating the coincidence factors. Typical values

[60] This parameter is also used to calculate the Wholesale Market Price Impact benefit.
[61] Bulk transmission effectively has the same coincidence factor as generation since non-project specific transmission benefits are included in the Avoided LBMP and AGCC. This transmission coincidence factor is applicable for the Avoided Transmission Capacity Infrastructure and Related O&M benefit, which incorporates incremental value beyond what is included in the Avoided Generation Capacity Costs and Avoided LBMPs benefits.
[62] Note also that annual change in bulk system energy is used in the calculation of Wholesale Market Price Impact benefit.

are presented as examples in the sections below, however determining appropriate values for a specific project or portfolio may require additional information and calculation.

The first step is to identify the respective peak times for Bulk System, Transmission element or Distribution element as needed. Illustrations using a single peak hour are provided below.

5.1.1 Bulk System

According to the NYISO, the bulk system peak generally occurs during the afternoon hours of the hottest non-holiday weekday. The peak day might occur from May to October depending on the weather. For example, the New York Control Area (NYCA) peak typically occurs around hour ending 5 PM. Table 5-6 below represents the NYCA peak dates and times for the last 5 years, for illustrative purposes.

Table 5-6. NYCA Peak Dates and Times

Source: 2023 NYISO Load & Capacity Data Report

Year	Date	Hour Beginning
2018	8/29/2018	16
2019	7/20/2019	16
2020	7/27/2020	17
2021	6/29/2021	17
2022	7/20/2022	17

5.1.2 Transmission

The transmission peak as defined for the BCA may occur on a different day or hour than that of the NYCA peak. The peak is dependent on the location of specific transmission constraints where utility capital investment may be needed. If applicable, use the hour that the constrained element on the transmission system experiences its peak load. The main benefit is the deferred utility capital investment. Additionally, benefits of a reduced transmission peak are captured in Avoided LBMP and AGCC benefits.

5.1.3 Distribution

The distribution peak as defined for the BCA may occur on a different day or hour than that of the NYCA peak. The distribution system coincidence factor is highly project specific. The distribution system serving predominantly large office buildings will peak at a different time or day than that of a distribution system that serves a residential neighborhood. The distribution system peak may differ or may coincide with the NYCA system peak and/or the transmission peak. System-wide averages have been historically acceptable to use for some investment portfolios such as EE where the programs are broad based, and where system-wide averages are provided in the Technical Resource Manual (TRM), which assumes a historical coincidence for the NYCA peak. Going forward, for investments that are more targeted in nature, a more localized coincidence factor is more appropriate. The value of reducing the distribution peak is dependent on the location of constraints in the distribution equipment where utility capital investment may be needed. Note that in some cases with very local benefits objectives, even if the coincidence factor is high, the capacity value of a DER to the distribution system may be very low or zero if no constrained element is relieved (e.g., an increase in capacity in that location is not required, thus there is no distribution investment to be deferred even with highly coincident DER behavior).

5.2 Estimating Coincidence Factors

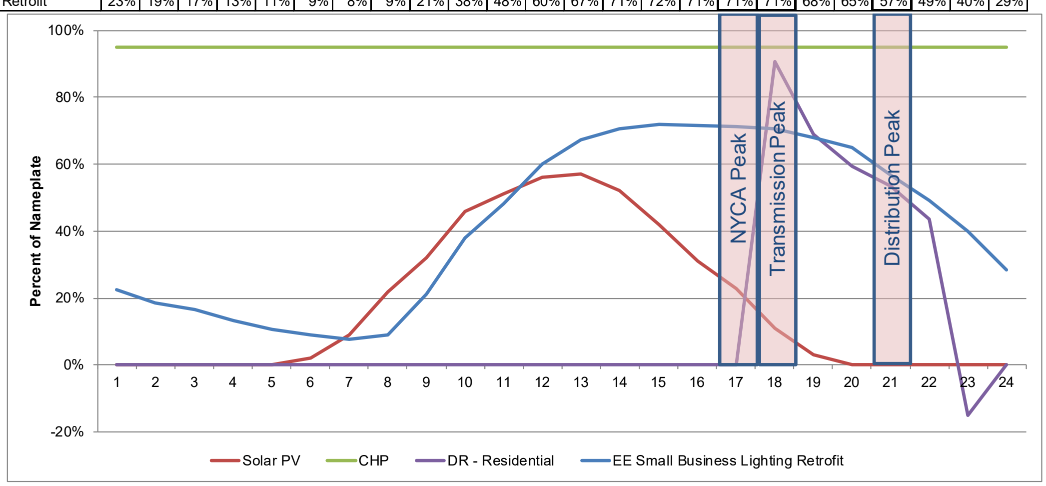
There are multiple approaches for estimating coincidence factors that apply different levels of rigor. Rigorous approaches could be defined and applied across a range of DER; however, such an approach is likely to require a significant amount of granular information (e.g., 8760-hour load shapes for the DER projects and network information for specific locations) and significant time to analyze. Other approaches that require less granular information may be suitable in some cases and thus may be preferable.

One approach for estimating coincidence factors is to model the energy behavior of the DER on a time-specific basis (e.g., hourly output) and normalize this behavior to the nameplate capacity. This time specific, normalized behavior can then be compared to the relevant peaks (i.e., system, transmission, and distribution) on the same time specific basis to determine the coincidence factors. The time basis can be done on an annual basis, using a “typical day”, or using a subset of hours that are appropriate for that specific DER.

Figure 5-1 provides an illustrative plot of the hourly DER output curves for a summer peak day as a graphical demonstration of the calculation method. The y-axis represents the percentage of DER output vs. the DER nameplate, and the x-axis shows the hour of the peak day. By using the NYCA Bulk System, Transmission or Distribution peak hour and the respective percentage of peak, the coincidence factors can be determined based on the type of resource.

Figure 5-1. Illustrative Example of Coincidence Factors

	Hour Ending																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Solar PV	0%	0%	0%	0%	0%	2%	9%	22%	32%	46%	51%	56%	57%	52%	42%	31%	23%	11%	3%	0%	0%	0%	0%	0%
CHP	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
DR - Residential	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	91%	69%	59%	53%	43%	-15%	0%
EE Small Business Lighting Retrofit	23%	19%	17%	13%	11%	9%	8%	9%	21%	38%	48%	60%	67%	71%	72%	71%	71%	71%	68%	65%	57%	49%	40%	29%



Source: Consolidated Edison Company of New York

Individual DER example technologies have been selected as examples and are discussed below.[63]

[63] The BCA Handbook does not attempt to provide an example of a portfolio of interdependent DER, such as those that might be procured to provide an NWS approach. Such a combination of project specific DER and distribution system information is less. generalizable for assessing transmission and distribution coincidence factors, and less informative as an example than the individual DER examples selected. For example, when assessing NWS projects, it is necessary to assess their functional equivalence with traditional wired solutions. This requires understanding the potentially complex interactions between the DER, assessing their joint reliability relative to that of traditional wired investment, and understanding the uncertainties in performance that may impact ability to maintain safe, reliable, and economic energy delivery. The BCA handbook incorporates derating factors in various benefit.

The values for the DER illustrative examples have been compiled from various sources and each of these sources may apply different valuation techniques. Some sources performed extensive simulations to generate statewide averages, while others performed calculations on a variety of system specification assumptions. For example, the coincidence factors for the solar example were calculated in the E3 Report, described above, based on a simulation of many solar systems across New York.

An area for further investigation will be to assess and develop a common approach and methodology for determining the values for DER-specific parameters for each type of DER.

5.3 Solar PV Example

Solar PV is selected to depict an *intermittent* DER, where the electricity generation is dependent on the resource availability, in this case solar irradiance. The parameter assumptions and methodology used to develop those assumptions were obtained from the E3 Report.

5.3.1 Example System Description

The solar PV used in this example is a 4 kW-AC residential rooftop system which is connected to the local distribution system through the customer's meter. These details allow for an estimate of material and installation costs, but there are several other system details required to estimate system energy output, and therefore a full benefit analysis. Local levels of solar irradiance, panel orientation (azimuth angle from north, south, east, west), tilt (typically, 0°-25° for rooftop systems located in NY) and the addition of a tracking feature, as well as losses associated with the balance of system equipment (e.g., inverters, transformers) and system degradation over time each impact the system's capacity factor and coincidence factors with the bulk system, transmission and distribution.

The impact and value of solar output on NYCA system, transmission, and distribution systems must consider the intermittent behavior of solar generation. To conduct this analysis, an hourly profile of generation based on project-specific parameters, as well as corresponding NYCA system, transmission, and distribution load profiles, provide the information that is necessary to estimate the coincidence factors for this example DER technology. The values that follow in this section are for a system-wide deployment of solar PV.

5.3.2 Benefit Parameters

The benefit parameters in Table 5-7 for the intermittent solar PV example are based on information provided in the E3 Report.

The E3 Report determined utility-specific average values for coincidence and capacity factors. The statewide weighted averages based on electricity delivered by utility are provided in Table 5-7. These values are illustrative estimates that may be refined as more data becomes available. To determine project-specific benefit values, hourly simulations of solar generation, peak hours, and energy prices (LBMP) would need to be calculated based on the project's unique characteristics. Similarly, utility and location-specific specific information would be needed. For example, the distribution coincidence factor can vary significantly depending on time of the feeder and substation peak.

Calculations to account for these elements, but a discussion of those factors would complicate this section significantly, and so it is not included.

Table 5-7. Solar PV Example Benefit Parameters

Parameter	Value
SystemCoincidenceFactor	36%
TransCoincidenceFactor	8%
DistCoincidenceFactor	7%
∆Energy (time-differentiated)	Hourly

Note: This illustration would change as specific projects and locations are considered.

- **SystemCoincidenceFactor:** This value represents the "effective" percent of the nameplate capacity, 4 kW-AC that reduces the system peak demand, resulting in an avoided generation capacity benefit. The 36% calculated from results of the E3 Report aligns with the coincidence values presented in the NYISO ICAP manual, which provides a range from 26%-43% depending on system azimuth and tilt angle.[64] It is acceptable to use the summer average because in this BCA, the AGCC is calculated based on the summer impact on-peak load (Section 4.1.1).
- **TransCoincidenceFactor:** The transmission coincidence factor included is for the New York average sub-transmission coincidence factor. This value would be highly project-specific, as it depends on the generation profile of the system, and the load profile for the site-specific area on the sub-transmission system.
- **DistCoincidenceFactor:** The distribution coincidence factor is lowest. Residential distribution feeders and substations often peak during early evening hours when solar output is low.[65] This value would be highly project-specific, as it depends on the generation profile of the system, and the load profile for the site-specific area on the distribution system.
- **∆Energy (time-differentiated):** As discussed above solar output would be higher during daylight hours and summer months. As hourly solar profiles are available from SAM, it would be appropriate to compare the projected energy output with hourly LBMPs.

5.4 Combined Heat and Power Example

CHP is an example of a *baseload* DER which typically operates during system, transmission, and distribution peaks.

5.4.1 Example System Description

CHP depicts a *baseload* DER where the electricity is generated at all hours, except during maintenance. The CHP system used in this example is a 100-kW capacity natural gas-fired engine unit sized for commercial thermal load following applications. In this simplified example, the 100-kW system is assumed to be small relative to the commercial building's overall electric load and thus the system operates at full electrical generating capacity at all times, except when it is down for maintenance. The example is described in EPA's *Catalog of CHP Technologies*.[66]

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[64] New York Independent System Operator (NYISO), Installed Capacity Manual 4 (June 2016), pp.4-23.
[65] *See* E3 Report, p. 49.
[66] United States Environmental Protection Agency and Combined Heat and Power Partnership, *Catalog of CHP Technologies* (EPA Catalog of CHP Technologies) (September 2017): https://www.epa.gov/sites/default/files/2015-07/documents/catalog_of_chp_technologies.pdf.

5.4.2 Benefit Parameters

Benefit parameters for the *baseload* CHP example are a combination of assumptions on system use and system characteristics.

Coincidence and capacity factors are derived from the assumption that the CHP is used as a baseload DER whereby the CHP system would be running at full capacity all the time, except for downtime for maintenance. Since it is not always possible to schedule downtimes, the CHP unit is assumed to provide 95% power output at all hours, assuming it is down for maintenance 5% of the year.[67]

The carbon and criteria pollutant intensity can be estimated using the EPA's publicly available CHP Emissions Calculator.[68] CHP Technology, Fuel, Unit Capacity' and Operation were the four inputs required. An example is a reciprocating engine, fueled by natural gas, 100 kW in capacity operating at 95% of 8,760 hours/year.

To complete a project-specific analysis, actual design parameters and generation profiles would be needed to assess the likelihood of coincidence, emissions, and capacity factors.

Table 5-8. CHP Example Benefit Parameters

Parameter	Value
SystemCoincidenceFactor	0.95
TransCoincidenceFactor	0.95
DistCoincidenceFactor	0.95
CO_2Intensity (metric ton CO_2/MWh)	0.141
PollutantIntensity (metric ton NO_X/MWh)	0.001
ΔEnergy (time-differentiated)	Annual average

Note: This illustration would change as specific projects and locations are considered.

- **SystemCoincidenceFactor:** The system coincidence factor is 0.95 under the assumption that the CHP system is always running apart from downtime for maintenance or during forced outages.
- **TransCoincidenceFactor:** The transmission coincidence factor is 0.95 under the assumption that the CHP system is always running apart from downtime for maintenance or during forced outages.
- **DistCoincidenceFactor:** The distribution coincidence factor is 0.95 under the assumption that the CHP system is always running apart from downtime for maintenance or during forced outages.
- **CO_2Intensity:** This value was the output of EPA's calculator, provided in tons/year and then converted to metric ton/MWh as required for input into the BCA (Section 4.4.1).
- **PollutantIntensity:** This value was the output of EPA's calculator, provided in tons/year and then converted to metric ton/MWh as required for input into the BCA (Section 4.4.2). There are no SO_2 emissions from burning natural gas.

[67] United States Environmental Protection Agency and Combined Heat and Power Partnership, *Catalog of CHP Technologies* (EPA Catalog of CHP Technologies): https://www.epa.gov/chp/catalog-chp-technologies.

[68] EPA CHP Emissions Calculator: https://www.epa.gov/chp/chp-emissions-calculator.

- **∆Energy (time-differentiated):** Assuming the CHP is used as a baseload resource, with the exception of downtime for maintenance, capacity factor is 95%. Because it is not possible to predict when the downtime may occur, using annual average LBMP would be appropriate.

5.5 Demand Response Example

DR depicts an example of a *dispatchable* DER where the resource can be called upon to respond to peak demand.

5.5.1 Example System Description

The system dispatchable DR technology described herein is a programmable and controllable thermostat in a residence with central air conditioning that is participating in a direct load control program.

DR is a dispatchable DER because it reduces demand on request from the system operator or utility.[69] Each DR program has unique requirements for notification time, length of demand reduction, number of calls, and frequency of calls. A DR resource is typically available only for limited hours in a year (e.g., <100 hrs) and limited hours per call. The major benefit from DR is ability to reduce peak demand. The particular use case or operational objective of the DR determines the value for its coincidence factors.

The coincidence factors shown below are based on experience and metering in Con Edison's Direct Load Control Program.[70] This DR example is specifically for a DR event called for five hours between the hours of 5pm and 10pm. The coincidence factors can and will change based on when DR event is called, customer response (e.g., overrides), device availability, load availability, and other project and technology specific factors. Care should be taken to consider all these factors when determining appropriate coincidence factors for projects and portfolios.

The value of reduced energy use attributable to the DR asset can be calculated using the average LBMP of the top 50 hours of system peak. A more accurate energy calculation would consider the expected number of times that DR was called in a given year as well as the length of the calls beyond the peak hour itself (e.g., 2-hour events, 4-hour events). This calculation will differ if the DR asset is intended to defer another peak, or if the DR program has a substantially different frequency of calls. The number of hours averaged should be based on the frequency of DR calls and the selection of those hours should be based on when the DR calls will be made.

5.5.2 Benefit Parameters

The benefit parameters described here are assumed based on the example and considerations described above. Coincidence factors might differ based on the call windows of the DR resource being evaluated.

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[69] Some DR programs may be "dispatched" or scheduled by third-party aggregators.
[70] These factors are specifically from the July 15 – 19, 2013 heat wave.

Table 5-9. DR Example Benefit Parameters

Parameter	Value
SystemCoincidenceFactor	0.0
TransCoincidenceFactor	0.91
DistCoincidenceFactor	0.53
∆Energy (time-differentiated)	Average of highest 100 hours

Note: This illustration would change as specific projects and locations are considered.

- **SystemCoincidenceFactor:** The system coincidence factor is 0.0, based on Con Edison’s Direct Load Control Program, as illustrated in Figure 5-1. This factor will change based on the DR call window, customer response, device availability, load availability, as well as the timing of the system peak.
- **TransCoincidenceFactor:** The transmission coincidence factor is 0.91, based on Con Edison’s Direct Load Control Program, as illustrated in Figure 5-1. This factor will change based on the DR call window, customer response, device availability, load availability, as well as the timing of the transmission peak.
- **DistCoincidenceFactor:** The distribution coincidence factor is 0.53, based on Con Edison’s Direct Load Control Program, as illustrated in Figure 5-1. This factor will change based on the DR call window, customer response, device availability, load availability, as well as the timing of the distribution peak.
- **∆Energy (time-differentiated):** DR would be dispatched a limited number of hours during the year. NYISO may only call upon DR for ~50 hours in a year. The energy savings can be estimated based on the average demand savings (not peak) expected over the hours called, times the number of hours the DR resource is expected to be called. This average reduction would be multiplied by an appropriately time differentiated LBMP.

5.6 Energy Efficiency Example

Energy efficient lighting depicts a *load-reducing* DER where the use of the technology decreases the customer’s energy consumption as compared to what it would be without the technology or with the assumed alternative technology.

5.6.1 Example System Description

The energy efficient lighting used in this example is indoor installation of tubular LEDs in a commercial small business setting. The peak period for this example is assumed to occur in the summer during afternoon hours.

EE, including lighting, is a *load-reducing* modifier because it decreases the customers’ energy consumption and load shape, which in turn, reduces the system, transmission and distribution peak. This example of small business-setting lighting system assumes that the coincidence factor is calculated during operational hours when the load reduction due to this lighting technology is expected to occur at the time of the system peak, as well as the during the transmission and distribution peaks. The illustrative values presented below are based on a recent Con Edison metering study.

5.6.2 Benefit Parameters

The benefit parameters described here are based on Con Edison experience with small commercial lighting projects.

Table 5-10. EE Example Benefits Parameters

Parameter	Value
SystemCoincidenceFactor	0.71
TransCoincidenceFactor	0.71
DistCoincidenceFactor	0.57
∆Energy (time-differentiated)	~9 am to ~10 pm weekdays

Note: This illustration would change as specific projects and locations are considered.

- **SystemCoincidenceFactor:** The system coincidence factor is 0.71 based on a recent Con Edison meter study as illustrated in Figure 5-1. The factor is highly dependent on the technology, customer type, as well as timing of the system peak.
- **TransCoincidenceFactor:** The transmission coincidence factor is 0.71 based on a recent Con Edison meter study as illustrated in Figure 5-1. The factor is highly dependent on the technology, customer type, as well as timing of the transmission peak.
- **DistCoincidenceFactor:** The distribution coincidence factor is 0.57 based on a recent Con Edison meter study as illustrated in Figure 5-1. The factor is highly dependent on the technology, customer type, as well as timing of the distribution peak.
- **∆Energy (time-differentiated):** This value is calculated using the lighting hours per year, divided by the total hours in a year (8,760). This time period is subject to building operation, which, in this example is assumed between 9 am and 10 pm, 6 days a week, 50 weeks a year. This would define the corresponding period for determining an average LBMP that would be used to calculate the benefit.

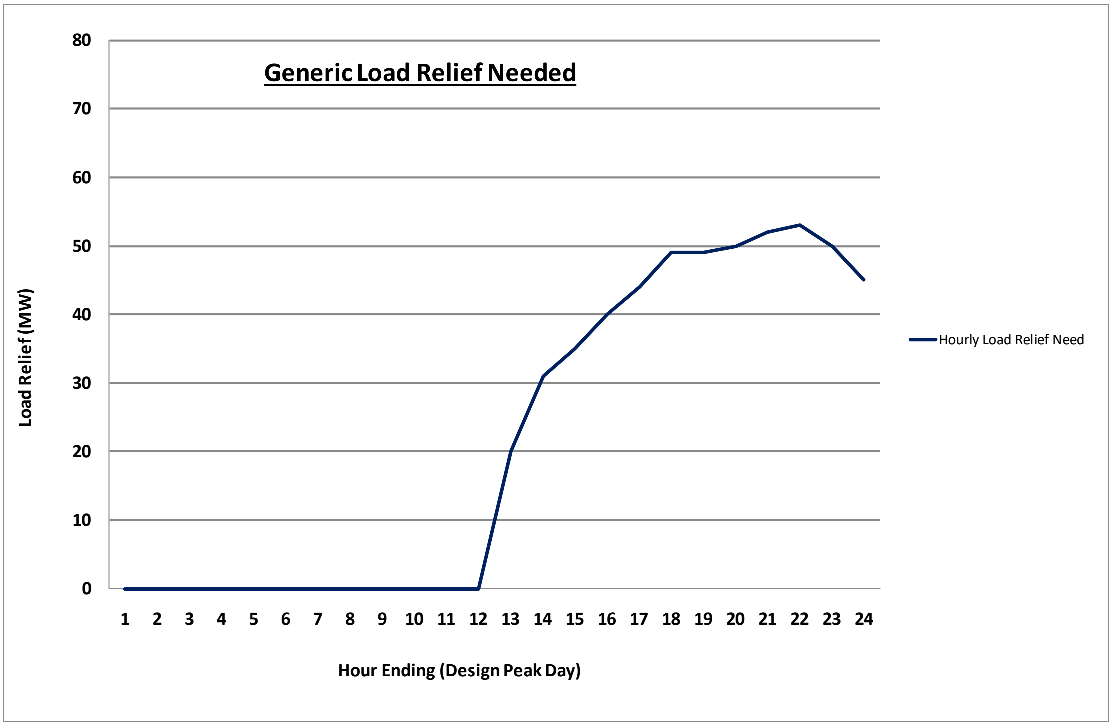
5.7 Portfolio Example

This example assumes that a segment of the distribution system needs locational load relief, illustrates how that relief might be provided through a portfolio approach, and examines some of the qualitative considerations impacting the development of the portfolio solution.

5.7.1 Example Description

The hourly locational load relief need is defined in Figure 5.2. This example is most likely representative of a locational need in a densely populated urban area and captures many of the considerations that go into the development of a portfolio of resources to provide a non-wires solution to the locational need.

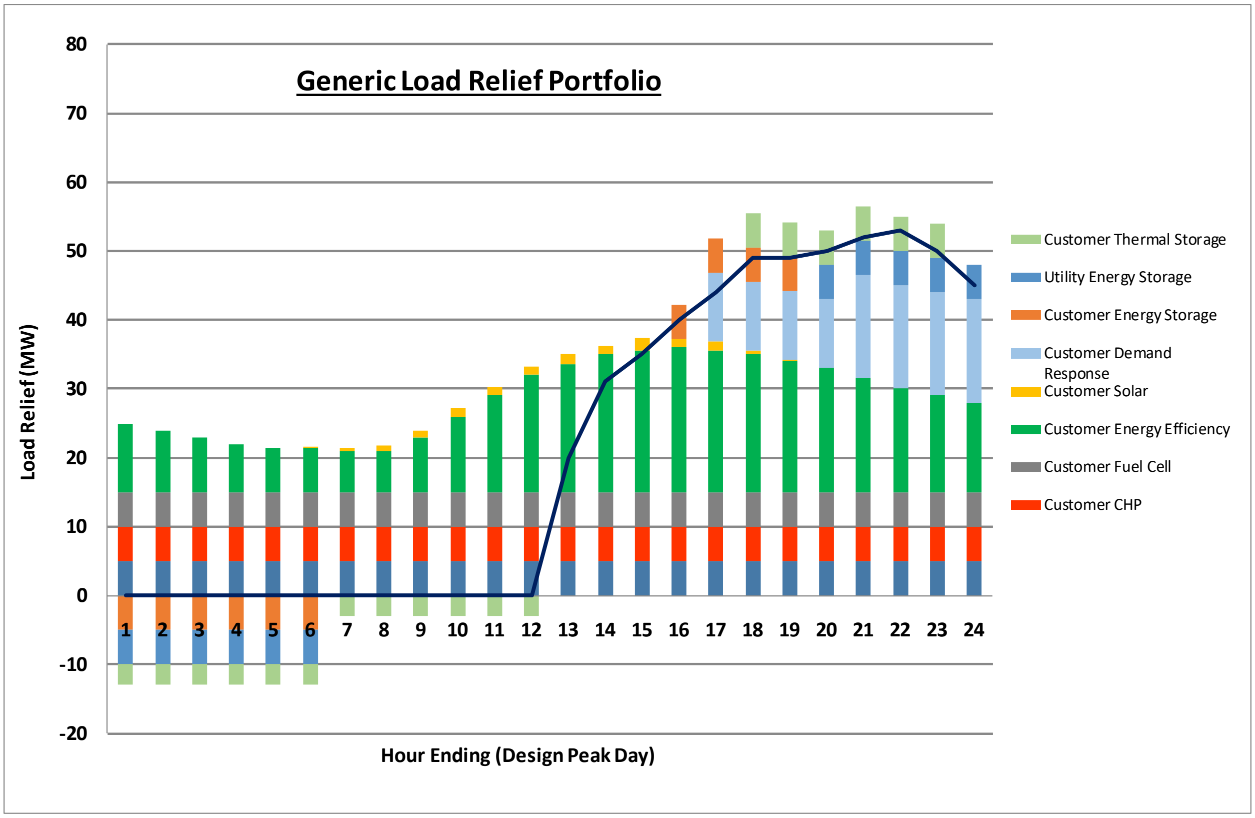
Figure 5.2. Location Load Relief Requirement



5.7.2 Example Solution

Unlike the specific examples considered previously in this section, the use of a portfolio approach to solve a need is a more complicated exercise as it will involve a solicitation for resources to address the load relief requirement. While many technologies in isolation have the potential to address portions of the load relief requirement by passing an individual benefit cost analysis for that technology, the utility must determine the most cost-effective combination of technologies that fully addresses the relief requirement through the application of a benefit cost analysis to portfolios of resources. Figure 5.3 provides an illustrative example of how the load relief requirement in Figure 5.2 might theoretically be solved.

Figure 5.3 – Theoretical Solution for Load Relief Need



BCA results are only one of many factors that go into the development of a load relief portfolio. The development of a portfolio solution requires consideration of a myriad of considerations which include but are not limited to:

- Public Policy – The ability of respondent's proposal to address Commission public policy objectives.
- Proposal Content – The quality of information in a proposal must permit a robust evaluation. Project costs, incentives, and the $/MW peak payment must be clearly defined.
- Execution Risk - The expected ease of project implementation within the timeframe required for the solicitation (e.g., permitting, construction risks, and operating risks).
- Qualifications - The relevant experience and past success of Respondents in providing proposed solutions to other locations, including as indicated by reference checks and documented results.
- Functionality - The extent to which the proposed solution would meet the defined functional requirements and the ability to provide demand reduction during the peak time and area of need.
- Timeliness - The ability to meet utility's schedule and project deployment requirements for the particular non-wires opportunity, reflecting that the detailed project schedule from contract execution to implementation and completion of projects is important for determination of feasibility.

- Community Impacts - The positive or negative impact that the proposed solution may have on the community in the identified area (e.g., noise, pollution).
- Customer Acquisition - The extent to which a respondent's proposed solution fits into the needs of the targeted network(s), the customer segment of the targeted network(s) and the customer acquisition strategy (preliminary customer commitments from applicable customers are highly desirable.)
- Availability and Reliability - The ability of the proposed solution to provide permanent or temporary load relief will be considered, along with the dependability and benefits that would be provided to the grid.
- Innovation – Innovative solution that (1) targets customers and uses technologies that are currently not part of Con Edison's existing programs, (2) targets generally underserved customer segments, and/or (3) is based on the use of advanced technology that helps foster new DER markets and provides potential future learnings.

APPENDIX A. UTILITY-SPECIFIC ASSUMPTIONS

This section includes utility-specific data. Each data point represents a parameter that is used throughout the benefit and cost methodologies described in Section 4.

The discount rate is set by the utility cost of capital, which is included in Table A-1. Benefit and Cost streams should be discounted at the Weighted Average Cost of Capital (WACC) unless specified otherwise.

Table A-1. Utility Weighted Average Cost of Capital, 2023-2025

Source: CECONY Case 22-E-0064

Year	Regulated Rate of Return
2023	**6.75%**
2024	**6.79%**
2025	**6.85%**

The variable loss percent is used to account for losses occurring upstream from the load impact. Both the fixed and variable loss percent values may be affected by certain projects which alter the topography of the transmission and/or distribution systems. Utility-specific system annual average loss data is shown in Table A-2. Loss percentages come from utility-specific loss studies. The average loss percent and peak loss percent are assumed to be equal.

Table A-2. Utility Loss Data

Portion of T&D Delivery System	Voltage Segment	Loss Type	
		Fixed	**Variable**
Transmission	500 kV	0.00%	0.00%
	345 kV	0.32%	0.52%
	138 kV	0.34%	0.50%
	69 kV	0.03%	0.05%
	TOTAL	**0.69%**	**1.07%**
Distribution	Primary	0.20%	1.12%
	Secondary	0.00%	1.56%
	Metering	0.18%	0.00%
	Equipment	0.78%	0.39%
	TOTAL	**1.16%**	**3.08%**
Unaccounted For		0.00%	0.65%
TOTAL		**1.85%**	**4.79%**
Source: Con Edison's 2007 Electric System Losses study			

Utility-specific system average marginal costs of service are found in Table A-3. Utility-specific system average marginal costs of service are found in Table A-3 Utility System Average Marginal Costs of Service in terms of $/kW-year. The nominal costs after 2024 can be estimated by escalating the costs by 3% annually.

Table A-3. Utility System Average Marginal Costs of Service

Source: Consolidated Edison 2016 Rate Case Filing DAC-3 Schedule 1

Year	Transmission ($/kW-yr)	Primary Distribution ($/kw-yr)	Secondary Distribution ($/kW-yr)
2020	$31.27	$159.75	$95.80
2021	$32.70	$169.06	$98.67
2022	$34.06	$175.63	$101.63
2023	$34.64	$184.33	$104.68
2024	$38.34	$193.14	$107.82