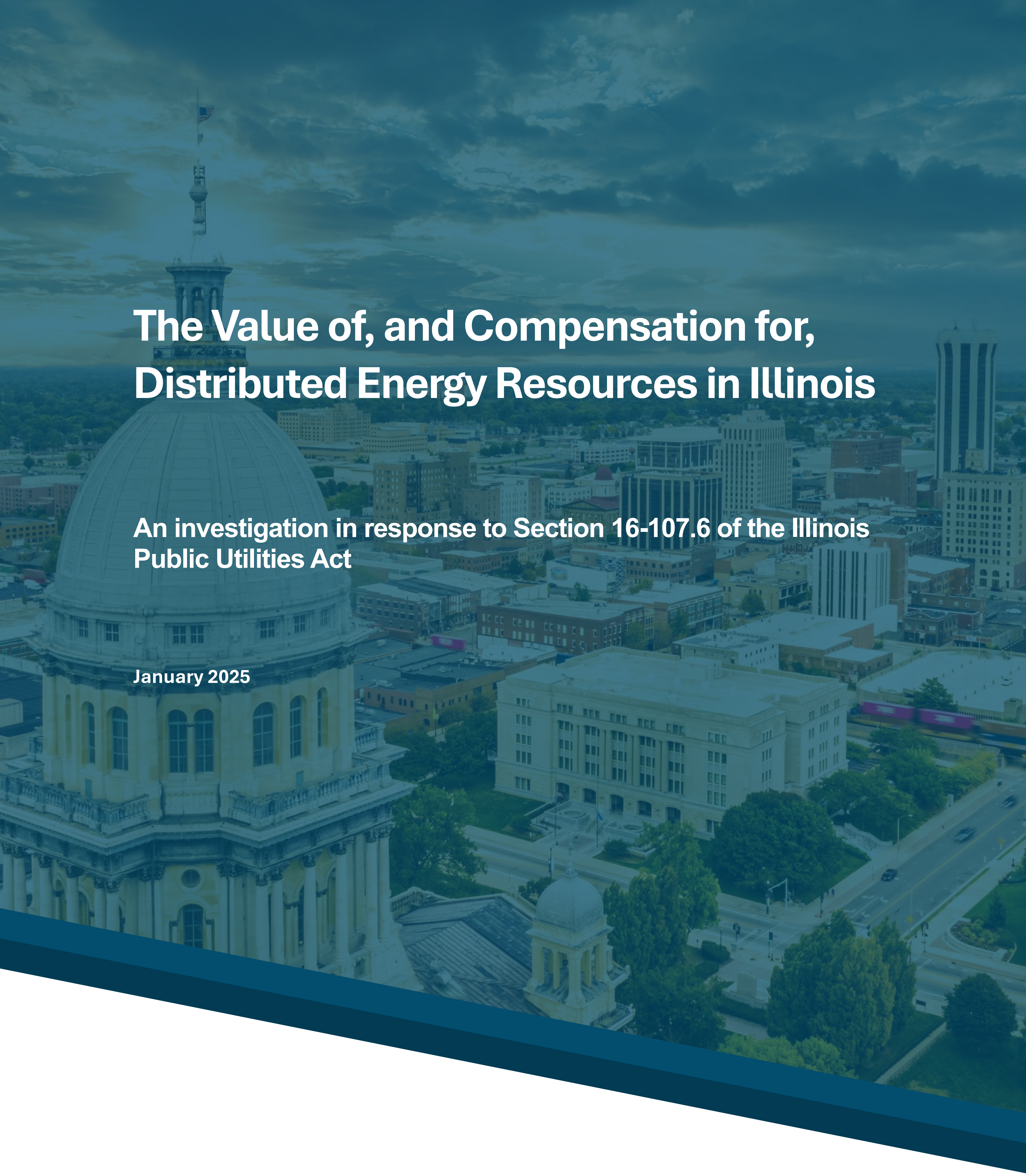

The Value of, and Compensation for, Distributed Energy Resources in Illinois

An investigation in response to Section 16-107.6 of the Illinois Public Utilities Act

January 2025

Energy+Environmental Economics

The Value of, and Compensation for, Distributed Energy Resources in Illinois

Prepared for the Illinois Commerce Commission

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Acronym Definitions

Acronym	Definition
ABP	Adjustable Block Program
ATB	Annual Technology Baseline
BCA	Benefit/Cost Analysis
BTM	Behind-the-Meter
CAIDI	Customer Average Interruption Duration Index
CEJA	Climate and Equitable Jobs Act
CS	Community Solar
DER	Distributed Energy Resource
DG	Distributed Generation
DLOL	Direct Loss-of-Load
DOE	Department of Energy
DR	Demand Response
EIA	Energy Information Administration
EJ	Environmental justice
EJC	Environmental Justice Community
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
ICC	Illinois Commerce Commission
ICE	Interruption Cost Estimate
IEEE	Institute of Electrical and Electronics Engineers
IPA	Illinois Power Agency
IRA	Inflation Reduction Act
ITC	Investment Tax Credit
LIHEAP	Low Income Home Energy Assistance Program
LMI	Low and Middle Income
LMPs	Locational Marginal Prices
LOLE	Loss-of-Load Expectation
LRTP	Long-Range Transmission Planning
LSE	Load Serving Entity

Acronym	Definition
MCOSS	Marginal Cost of Service Study
MHDV	Medium- and Heavy-Duty Vehicle
MISO	Midcontinent Independent System Operator
NEM	Net Electricity Metering
NOAA	National Oceanic and Atmospheric Administration
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
NTS	Network Transmission Service
OCC	Overnight Capital Cost
PCAF	Peak Capacity Allocation Factor
PCT	Participant Cost Test
PIPP	Percentage of Income Payment Plan
PJM	Pennsylvania-New Jersey-Maryland (System Operator)
PRM	Planning Reserve Margin
PUA	Public Utilities Act
PV	Photovoltaic (Solar)
REC	Renewable Energy Credit
RFP	Request for Proposals
RIM	Ratepayer Impact Measures
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Operator
RTP	Real-Time Pricing
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SMART	Solar Massachusetts Renewable Target
TOU	Time-of-Use
TRC	Total Resource Cost
V2G	Vehicle-to-Grid
VOLL	Value of Lost Load
VPPs	Virtual Power Plants

Executive Summary

On September 15, 2021, the Climate and Equitable Jobs Act (CEJA) was signed into law with the goal of guiding the transition of Illinois into a more sustainable and equitable energy future. The Act recognizes that, due to their physical location close to load, Distributed Energy Resources (DERs) can play a unique role in providing value to the electric distribution grid, but the state lacks both a framework to quantify this value and a compensation mechanism to promote DER adoption and dispatch that helps realize this value. To address this gap, the law mandates that the Illinois Commerce Commission (ICC) initiate an investigation into the value of, and compensation for, DERs. This report is the outcome of that investigation.

DERs may provide value to the grid in several ways. They can provide energy and capacity, relieve stress on transmission and distribution systems during constrained hours, provide Greenhouse Gas (GHG) benefits, and avoid system losses given their proximity to load. They also can provide non-monetized benefits, which do not impact utility costs. DER customers may receive compensation for these values through a reduction in their electricity bills based on the retail rate – a process known as net metering – and through DER-specific incentive programs. Chief among the directives provided by CEJA is to establish compensation formulas and initial values for two DER compensation vehicles:

+ A **Base Rebate**, which cannot vary by any variable other than DER type (e.g. distributed generation [DG] or energy storage), must be paid upfront, and has a floor value of either $250 per kW or $300 per kW for DG[1].
+ **Additive Services** incentives, which can vary by DER location, operational time, and performance, and have no floor value.

Between the Base Rebate and Additive Services mechanisms, a DER should be compensated for the value it provides to the distribution grid and for other non-monetized values, provided the DER is not otherwise already compensated for these values.

Below, we provide a list of key findings from the study, and we summarize the proposed compensation formula and values that are motivated by these findings.

Proposed DER Compensation Formula

We recommend a compensation structure that uses two benefit-cost tests to screen for net benefits of a DER before determining whether it qualifies for incentives above the Base Rebate floor or a nonzero Additive Services incentive. The two benefit cost tests used for screening are the Total Resource Cost Test (TRC+) and Ratepayer Impact Measures (RIM). TRC+ evaluates the costs and benefits of a given DER on all Illinois residents, while RIM evaluates the impact on all electric

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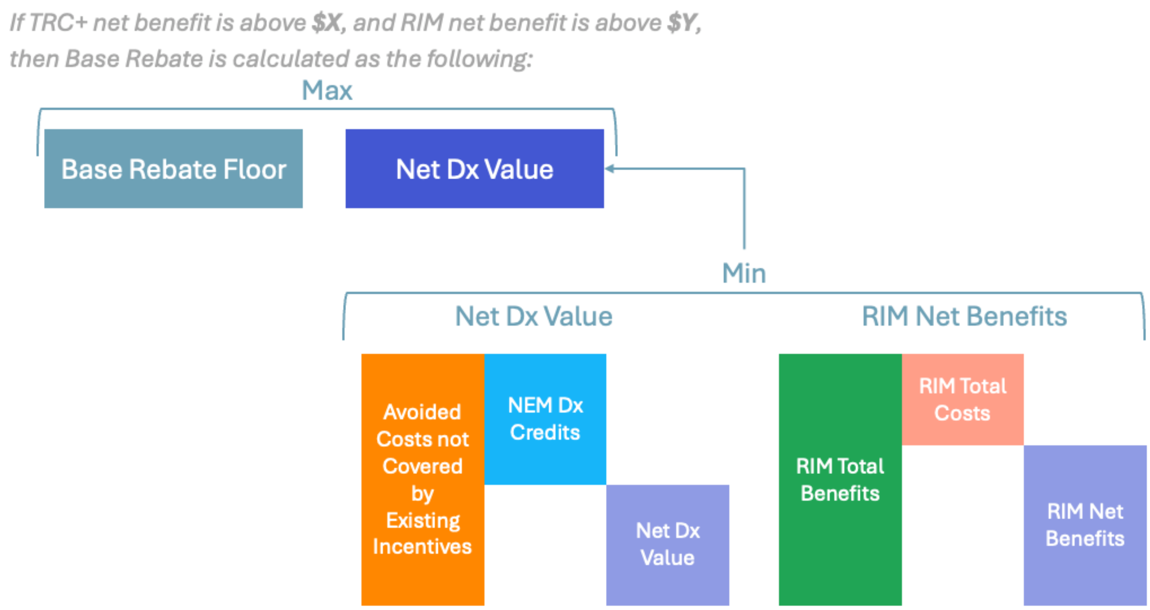
[1] $250/kW applies to DG that is not eligible for net metering under subsection (d), (d-5), or (e) of Section 16-107.5 of the Public Utilities Act (see Section 16-107.6 (c) 1). $300/kW applies to DG that is eligible for net metering under subsection (d), (d-5), or (e) of Section 16-107.5 of the Public Utilities Act (see Section 16-107.6 (c) 2).

ratepayers in Illinois. After screening, the proposed incentive splits, with one mechanism for distributed generation, such as solar, and a different mechanism for dispatchable DERs, such as storage.

For DG DERs that clear the screening, we calculate a Net Distribution Value by subtracting Net Electricity Metering (NEM) distribution compensation from Avoided Distribution Cost. This provides the recommended Base Rebate value, though it may be adjusted up to the Base Rebate floor or down to avoid creating a cost shift to non-participants (based on the RIM test). These steps of screening, calculating a Net Distribution Value, and adjusting are depicted in Figure 1. Our recommended threshold values for the cost-effectiveness screening are $X = Y = \$0$. This is equivalent to insisting that DERs provide net benefits to the state and to ratepayers.

Figure 1. Proposed base rebate compensation formula for distributed generation



For dispatchable resources, the Net Distribution Value provided an expectation for value provided, but we recommend compensating these resources through a performance-based Additive Services incentive. The amount of the incentive would be based purely on annual avoided distribution cost levelized over a 25-year period and paid out based on average kW output of the resource during call periods across each year.

The resulting recommended incentive values appear in Table 1. We recommend that all DG DERs receive no increase above the Base Rebate floor: RIM test results reveal affordability concerns for other ratepayers when participants adopt solar PV, and current low system average distribution values do not justify additional incentivization after accounting for the NEM distribution bill credit for avoided onsite consumption. Meanwhile, standalone storage can provide meaningful system value if signaled to dispatch in accordance with system and local needs. However, standalone storage has little existing incentive to promote adoption.

Table 1. Recommended compensation for DERs

DER	Unit	Base Rebate	Additive Services
ComEd			
Solar (net metering eligible)	$/kW$_{DC}$	**$300**	**-**
Solar (not net metering eligible)	$/kW$_{DC}$	**$250**	**-**
Standalone Storage	$/kW$_{AVG}$	-	**$25**
Ameren			
Solar (net metering eligible)	$/kW$_{DC}$	**$300**	**-**
Solar (not net metering eligible)	$/kW$_{DC}$	**$250**	**-**
Standalone Storage	$/kW$_{AVG}$	-	**$32**

We emphasize that, in contrast to the Base Rebate, the Additive Services compensation would be paid out each year. This means that, if the value were left unchanged over a system's 25-year expected lifetime, a DER with perfect response to all Additive Services events could receive a nominal total of $625 per kW ($310 per kW NPV), or $800 per kW ($400 per kW NPV), of capacity in its lifetime, depending on whether the DER is located in ComEd or Ameren territory. However, it is unlikely that a DER would capture the full value of the Additive Services incentive: a storage device may not have enough duration for an event, it may be reserving some capacity for other uses like reliability/resiliency, or it may be responding to competing dispatch signals from other value streams such as energy arbitrage.

Though we discuss the Additive Services incentive only as it would apply to energy storage, this proposed program could also allow participation from demand response (DR) and Electric Vehicles (EVs) discharging to the grid (often referred to as vehicle-to-grid or V2G). Participation from DR would require a process for determining baseline usage in the absence of incentive signal response, but this is a common hurdle for DR programs that could be overcome. V2G implementation would be more complex: V2G capabilities are in their infancy, with most EVs and chargers only able to curtail load but not export power to the grid, and interactions with existing and future EV-specific rates would need to be considered.

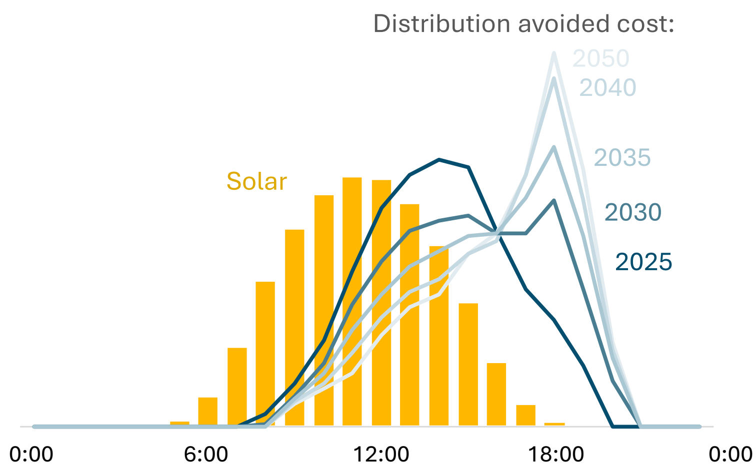
This time-dependent compensation mechanism for Additive Services serves multiple purposes. First, it protects ratepayers from the possibility that an upfront incentive could be paid to a DER that then underperforms and does not provide anticipated benefits to the grid. Second, it encourages dispatch of energy storage aligned with the greatest needs of the distribution system as decided by the system operators. And third, it promotes "learning by doing" by setting up a lower-stakes Additive Services mechanism today in anticipation of future assessments of distribution value that will place increased focus on the timing and location-specific nature of DER dispatch to provide value.

Key Findings

1. The value of DERs to the distribution system depends strongly on aligning DER output with hours of stress on individual feeders within the distribution system. The timing of this stress on the grid varies by location and will evolve over time, so dispatchable DERs are the resources best suited to relieve it.

The value of DERs to the distribution system is their ability to reduce load at critical times to avoid or defer new distribution infrastructure investment. The need for investment is driven only by the peak load on a given piece of equipment, meaning that few hours out of any given year are consequential in this determination. The critical hours vary for different feeders or even circuits within the distribution system, but our current insight into distribution system need only allows for system-wide consideration. At this level of granularity, critical hours are determined by system-wide load, and though this load does not vary spatially within a utility, the timing of critical hours does still evolve as load patterns change over time.

Figure 2. Normalized hourly average distribution avoided cost and solar profiles for ComEd territory



In Figure 2, we show the evolution of critical distribution system hours using the ComEd territory as an example, and we compare to a typical solar generation profile. The hourly output of solar, averaged over a year, remains static year-to-year, but the expected hours of highest value to the distribution system shift over time into the evening after the hours of high solar generation. Dispatchable resources, such as energy storage, can adapt their output profiles to this evolving need and are therefore better suited to provide distribution grid value than DERs like solar with fixed generation profiles.

We emphasize the disconnect between the avoidable cost of new distribution infrastructure and other embedded distribution system costs, which include historical system costs and future costs that cannot be avoided. Since rates recover this embedded cost, the distribution component in retail rates is higher than the distribution cost avoided by the utility due to

DERs. And without time-varying distribution rate components, there is no temporal connection between the distribution part of rates and avoided cost critical hours.

2. Distributed Generation may have some value to the state, but most of this value could be achieved by cheaper utility scale resources, and existing compensation for DG creates affordability concerns for non-participants.

We evaluate DER cost-effectiveness for a variety of combinations of customer type and DER technology. Specifically, we look at a modified Total Resource Cost Test (TRC+), Ratepayer Impact Measure (RIM), and Participant Cost Test (PCT) to respectively understand the value of DERs to the state, the impact of DER compensation on rate affordability for other ratepayers, and the strength of the financial incentive for customers to install DERs.

Figure 3. Cost-effectiveness results for select ComEd rooftop solar use cases

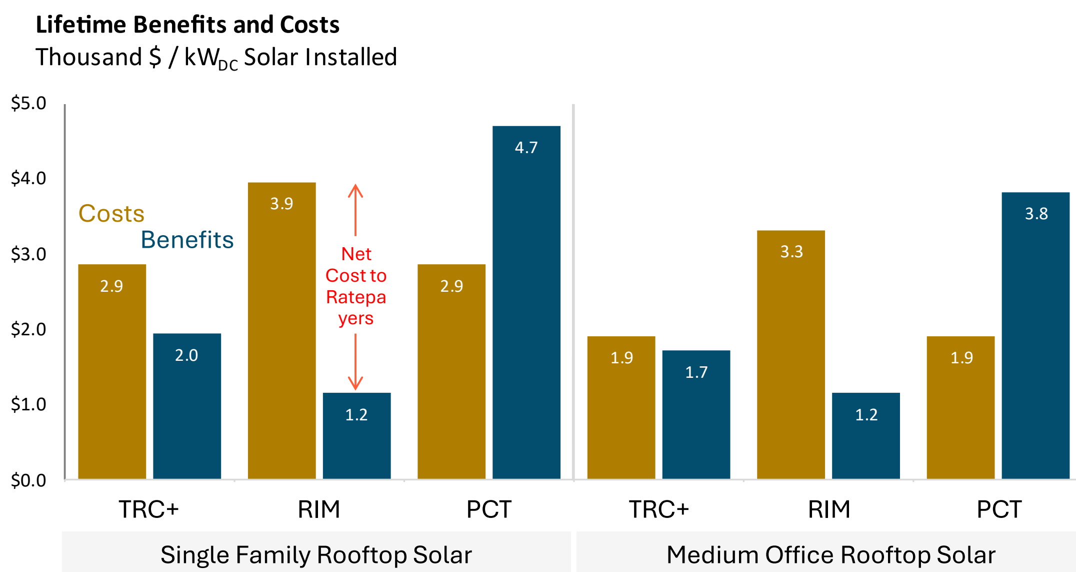


Figure 3 shows two use cases representing a residential and a commercial customer with rooftop solar in ComEd territory. These results accurately represent the dynamics observed for all the solar use cases we examine, including examples of community solar which tend to mirror non-residential use case results. Benefits to the state and to other ratepayers are muted by the lack of alignment of solar output hours with system avoided costs during the evening peaks. Meanwhile, incentives from participation in NEM, solar Renewable Energy Credit (REC) programs, and the floor value of the Base Rebate provide ample benefits for participants but also create large costs to be funded by ratepayers.

Among the benefits costs provided by solar to the grid, we find that distribution system avoided costs account for only 4% to 8% of total avoided costs. Accounting also for some benefit due to avoided losses, that leaves upwards of 85% of grid benefits associated with the bulk electric system. It is important to note that these bulk system benefits can be achieved by utility scale solar at considerably lower cost than distributed solar.

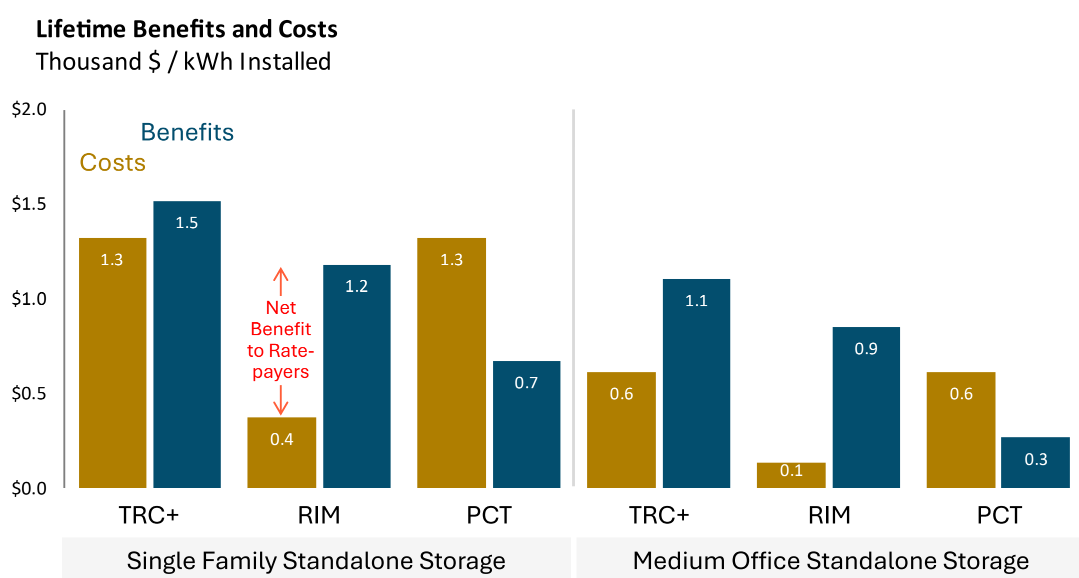
Based on these results, we do not recommend additional compensation for rooftop solar or community solar. Rooftop and community solar participants already see a strong incentive to adopt, and adding to this incentive would only exacerbate the cost burden on non-participating ratepayers. Also, for rooftop solar installations, the bill savings associated with avoiding the distribution component of rates is larger than the distribution value they provide to the grid. Even if the TRC+ were adjusted to more closely resemble a Societal Cost Test, concerns over costs shifting from solar customers to other ratepayers would persist.

3. Dispatchable DERs such as energy storage can provide value to the grid and to ratepayers, but compensation for these resources should be tied to performance to guarantee realization of potential value to the grid.

Similar to the solar use case figure above, Figure 4 shows two use cases representing a residential and a commercial customer with standalone energy storage in ComEd territory. The storage systems have four hours of duration and respond to a real-time price signal. In these cases, storage aligns discharge with system avoided costs, often leading to net benefits to the state. With no NEM benefits, no ABP rebate, and no Base Rebate floor, participant benefits are limited to arbitrage of the supply rate of the real-time price signal, which is matched with energy avoided cost value. This lack of incentives limits the motivation for customers to adopt DER storage.

As with solar, the majority of storage's modeled value accrues to the bulk grid, meaning that similar benefits could be achieved by utility scale energy storage at lower cost than by distributed energy storage. This also means that the system-wide value of distributed storage will decrease as utility scale storage resources are built and begin to soak up the bulk grid value.

Figure 4. Cost-effectiveness results for select ComEd standalone storage use cases



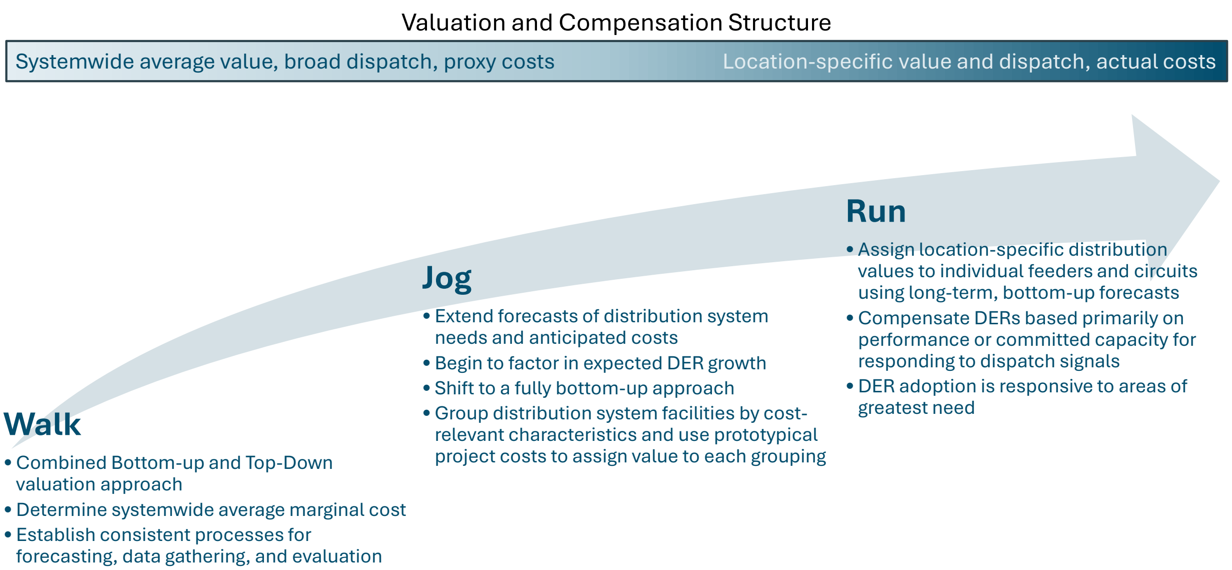
Based on these observations, we conclude that incentivization for DER energy storage is warranted, both to encourage adoption and to encourage DER dispatch that maximally benefits the grid. A performance-based incentive is particularly attractive since it provides an avenue to explicitly align DER dispatch with distribution avoided costs. This alignment is only incidental today insomuch as the distribution system needs align with energy price signals; a dynamic we cannot rely on for avoidance of new distribution infrastructure.

4. **Future data and process improvements can enable greater grid benefits, and the DER compensation values should be reevaluated to respond to these improvements and changes to state and national context.**

Through extensive conversations with ComEd and Ameren distribution engineers, we determined that today's best available data on the distribution system allows only for determining distribution value, or avoided costs, at the system level for each utility. However, the cost of investment in distribution infrastructure that can be avoided by DER is not evenly spread across a given system. Distribution investments occur in discrete location-specific chunks, such that the true distribution value is near zero in many locations, moderate in some locations, and very high in few locations with urgent need.

Representation of this nonuniformity should be a top priority. Spatially differentiated and anticipatory distribution investment costs could unlock new levels of DER value to the grid at high-need locations and avoid overcompensation at low-need locations. We recommend that Illinois follow a "walk, jog, run" process that allows distribution planning and DER compensation to evolve in steps as processes are established and data becomes available to support this vision of evolving complexity, which is outlined in Figure 5.

Figure 5. Walk/Jog/Run roadmap for distribution system value and compensation



Improved representation of bulk grid dynamics should be another priority to improve understanding of DER cost-effectiveness. The current modeled energy, generation, transmission, and emissions-related values of DER would better reflect Illinois conditions if they could be derived from a state-endorsed long-term electricity system plan and take resource adequacy into consideration. Stakeholders should be aware, however, that these updates would likely show decreased DER cost-effectiveness; long-term planning optimized for Illinois is likely to include additional utility scale solar and storage, resulting in less remaining value for distribution resources.

Alongside this evolution of distribution value determination, annual updates to the incentives should recognize key dependencies of the proposed compensation mechanism on external context. Key dependencies include the ABP incentives that are updated annually by the Illinois Power Agency, overlap with utility Non-wires Alternatives programs, updates to DER cost as deployment scales up, changes to rate design that alter distribution rate collection, and any guidance provided to the utilities through orders in the Grid Plan proceedings. While impacts from new developments in these arenas may be substantial, we do see a need for updating the Base Rebate or Additive Services incentive outside of the mandated annual cadence.

5. **Establishing an Additive Services benefit today is important to begin "learning by doing" so that future DER compensation can be spatially and temporally targeted to maximize efficient incentive spending.**

Today's available data limits the scope of a performance-based Additive Services incentive mechanism. Compensation can be tied to DER performance during call periods that align with local grid need to the extent that grid operators have this visibility, but there is no expectation of spatial granularity outside of the different prices assigned to the two utilities. Given this limitation, and the ability to force storage customers onto time-varying pricing schemes that, to some extent, align dispatch with grid needs, an argument could be made in favor of offering an administratively simpler storage incentive that does not depend on metered performance.

We still recommend a performance-based Additive Services incentive because of the value in establishing an incentive mechanism so that customers and utilities alike can grow accustomed to it before the stakes become higher. The value of DERs to the grid will spike in certain locations as distribution planning improves and large avoidable distribution infrastructure projects are identified. To avoid these potential costs, grid operators and planners need to be able to rely on targeted DER contributions to the grid. Building the trust required for relying on DER dispatch to avoid specific infrastructure takes time and practice. By implementing an incentive mechanism today that will be useful in the future, the state has time to build program enrollment and iron out details that stand in the way of smooth and reliable operations.

6. Several suggested DER benefits that are currently non-monetized may provide value outside of utility cost reductions, but none of these benefits can be quantified with sufficient certainty today to consider them for compensation.

We consider and explore a variety of non-monetized monetized (i.e. not reflected by the utility revenue requirement) benefits, which are listed in Table 2 along with our recommendations for inclusion in compensation today. As the table explains, we expect many of these benefits to become more reliably quantifiable in the future, and they will rely on an ability to track DER output and to vary compensation values based on fine-grain spatial and temporal resolution. Like for distribution value, realization of these values and potential compensation for them depends on establishing processes today to manage the data and dispatch at this granular scale. However, we recommend caution in compensating DERs for non-monetized benefits, since this practice guarantees bill increase for other ratepayers so long as the benefits do not impact utility spending.

Table 2. Non-Monetized benefits recommendation summary

Non-monetized Benefit	Recommended for Additive Services Compensation?	Additional Detail
Reliability	No	Already accrues to host customer
Resilience	Not in current version	Already accrues to host customer. May be shared with community in some cases
Environmental Justice	Not in current version	Additional policy guidance/consideration needed
Financial Risk Reduction from Fuel Price Volatility	Not in current version	Insufficient tracking of DER production vis-à-vis marginal generation source
Controllable Flexibility to Increase DER Interconnections	Not in current version	Certainty of impact unproven and valuation of impact not clear today
Methane Leakage	Not in current version	Insufficient tracking of DER production vis-à-vis marginal generation source
Voltage Regulation/ Optimization	Not in current version	Insufficient data to ensure positive value. Higher spatial resolution may allow for future valuation
Proximity to MHDV Charging	No	Insufficient data today. Will be included in distribution avoided cost once data is available

1 Introduction and Context

The Climate and Equitable Jobs Act (CEJA),[2] signed into law by Governor JB Pritzker on September 15, 2021, represents a comprehensive legislative effort to transition Illinois toward a more sustainable and equitable energy future. CEJA sets ambitious goals to achieve 100% carbon-free power by 2045 and outlines steps to eliminate pollutant emissions from all fossil-fuel power plants over time. Furthermore, it enhances Illinois's Renewable Portfolio Standards (RPS), raising the goals to 40% of the state's energy coming from renewable sources by 2030, and 50% by 2040.

CEJA amended Section 16-107.6(e) of the Public Utilities Act (PUA), mandating that the Illinois Commerce Commission (ICC) initiate an investigation into the value of, and compensation for, Distributed Energy Resources (DERs). These DERs are defined under CEJA as technologies located on the customer's side of the electric meter, including distributed generation, energy storage, electric vehicles (EVs), and demand response technologies. According to CEJA, community renewable generation projects, such as community solar, are also eligible for the compensation. We refer both roof-top solar and community solar, along with other generation resources, as distributed generation. These resources provide both system-wide and localized benefits to the grid, enhancing reliability and decreasing greenhouse gas (GHG) emissions. ICC selected the team of Energy and Environmental Economics (E3) and Viridis through a competitive bid process to assist in the investigation.

CEJA established eleven objectives to guide the investigation, which also served to inform pre-investigation workshops (Workshop Series 1), direct development of the compensation framework and guide the agenda and content of concurrent stakeholder meetings (Workshop Series 2). These eleven objectives are listed in Table 3, alongside the workshop(s) in which the objectives were primarily addressed and the section(s) of this report in which the objectives are discussed.

Among the objectives in the table, the call to establish two forms of DER compensation stands out:

- **Base rebate**: these are designed to compensate DERs for the system-wide grid services they provide for a period no less than 25 years. The base rebate cannot vary by customer, customer class, customer location, or any other variable. There are minimum rebate requirements depending on the DER type and time of implementation.
- **Additive services**: the services that distributed energy resources provide to the energy system and society that are not (1) already included in the base rebates for system-wide grid services; or (2) otherwise already compensated. Unlike base rebates, compensation for additive services can vary by DER location, operational time, and performance. There are no minimum compensation requirements for these services.

[2] https://ilga.gov/legislation/ilcs/documents/022000050K16-107.6.htm

Table 3. Investigation objectives

Objective	Workshop(s) when discussed	Report Section(s)
Include diverse set of stakeholders	All workshops	Stakeholder Engagement
Review best practices in calculating the value of DER benefits	Series 1, Series 2: Workshops 1 & 2	Introduction and Context; A Framework for Compensation Design
Review the full value of DERs and the manner in which each component of that value is or is not otherwise compensated	Series 2: Workshops 2 & 3	DER Benefits
Assess how the value of DERs may evolve based on the present and future technological capabilities of DERs and based on present and future grid needs	Series 2: Workshops 1-4	DER Benefits; Update process and future improvements
Establish an annual process and formula for the compensation of distributed generation and energy storage systems, and an initial set of inputs for that formula	Series 2: Workshop 4	Proposed Compensation Formula; Update process and future improvements
Establish base rebates that compensate distributed generation, community renewable generation projects, and energy storage systems for the systemwide grid services that they provide	Series 2: Workshops 3 & 4	Proposed Compensation Formula
Provide utilities a process to update the formula, annually, with inputs derived from their integrated grid plans	Series 2: Workshop 4	Proposed Compensation Formula; Update process and future improvements
Determine whether distributed energy resources can provide any additive services and the terms and conditions for the operation and compensation for those services	Series 2: Workshops 3 & 4	DER Benefits
Ensure that compensation for DERs, including base rebates and any payments for additive services, reflect all reasonably known and measurable values of the distributed generation over its full expected useful life	Series 2: Workshops 2 & 3	DER Benefits; Proposed Compensation Formula
Consider the electric utility's integrated grid plan developed pursuant to Section 16-105.17 of the Act to help identify the value of distributed energy resources for the purpose of calculating the compensation.	Series 2: Workshop 4	Proposed Compensation Formula; Update process and future improvements
Determine additional compensation for DERs that create savings and value for the distribution system by being co-located, or in close proximity to, electric vehicle charging infrastructure, primarily serving environmental justice communities, as outlined in the utility integrated grid planning process	Series 2: Workshop 3	DER Benefits

Figure 6. Base Rebate and Additive Services DER compensation outlook

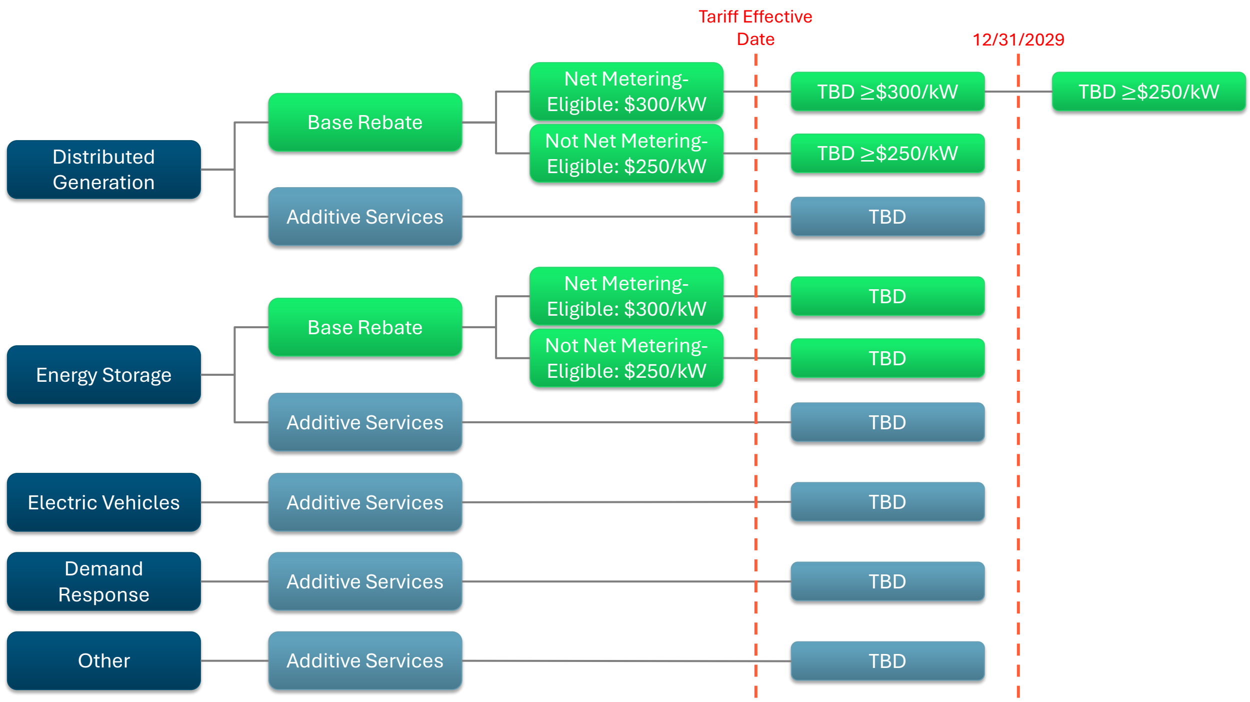


Figure 6[3] shows minimum base rebate and additive service eligibility for each DER under CEJA. As indicated by the graphic, distributed generation (DG) and energy storage devices are currently eligible to receive Base Rebates based on installed capacity. However, these values are due to be updated by the "tariff effective date" based on the outcome of this study and the subsequent proceeding. CEJA places a floor on the Base Rebate value for DG: $300/kW for DG that is eligible for net metering under subsection (d), (d-5), or (e) of Section 16-107.5 of the Public Utilities Act; and $250/kW for DG that is not eligible for net metering under subsection (d), (d-5), or (e) of Section 16-107.5 of the Public Utilities Act. Energy storage technologies have no similar prescriptive Base Rebate floor value, and CEJA places no conditions on potential Additive Services values.

To recommend compensation amounts and mechanisms for these forms of DER compensation, we focus on the following key tasks:

1. **Quantify DER benefits**: Identifying and quantifying various benefits that DERs provide to the grid and society.
2. **Design a compensation framework**: Establishing a formula for the compensation of distributed generation and energy storage systems, and an initial set of inputs for that formula.

[3] Adapted from https://icc.illinois.gov/api/web-management/documents/downloads/public/CEJA/Value%20of%20DER_ICC%20Workshop%209-29-23%20ComEd%20Presentation.pdf

3. **Evaluate base rebate**: Determining base rebates that compensate distributed generation, community renewable generation projects, and energy storage systems for the system-wide grid services that they provide.
4. **Evaluate additive services**: Assessing whether distributed energy resources can provide any additive services.
5. **Evaluate non-monetized benefits**: Identifying and quantifying additional compensation mechanisms for DERs that provide value to the distribution system, such as co-location with electric vehicle charging infrastructure or providing services to environmental justice communities.

In the following sections we take each of these tasks in turn. First by describing a framework for considering DER value and compensation, then by evaluating DER benefits and costs under current compensation structures, and finally by leveraging these results to formulate proposed compensation mechanisms. We note here and throughout the report that the framework described here represents version 1.0 in the journey to appropriately value and compensate DERs for their services to the distribution grid. We dedicate Section 6 to describing how we envision evolution beyond version 1.0, with a specific eye towards the data improvements that could have the most immediate substantial impact on DER valuation and compensation.

While this report reflects input from many stakeholders who participated in the workshop series that accompanied this study, we emphasize that the report does not represent a consensus position of the workshop participants. Workshops, written feedback, and one-on-one engagement with stakeholders provided avenues to understand stakeholder viewpoints and to make methodological adjustments based on their input. However, many points of contention remain between stakeholder preferences and the framework and formula proposed in this report. We note some of these points of contention, but these callouts do not form an exhaustive list.

2 A Framework for Compensation Design

DER compensation mechanisms strive to accomplish multiple concurrent and sometimes conflicting goals:

- **Encouraging Customer Adoption**. Without favorable price signals, customers and developers will not install DERs. Yet these resources can be critical to meeting decarbonization targets, strengthening grid resilience, and empowering customers to manage their energy use. By offering stable, transparent compensation for the benefits DERs provide, states can reduce project risk, spur innovation, and foster local economic development.
- **Managing Cost-Shift and Affordability**. An imbalance between monetized benefits of DERs and state incentives provided to DERs can lead to unintentional cost shifting to ratepayers from DER owners. In this scenario, ratepayers who do not (or cannot) adopt DERs may bear disproportionate costs for infrastructure and programs. Ensuring fair cost allocation and protecting affordability, especially for low-income or otherwise vulnerable customers, is therefore a central design principle. Compensation frameworks must consider the full range of system costs and benefits to balance the desire for rapid DER adoption with the need to avoid undue rate impacts on non-participants.
- **Realizing Value for the Grid and Community**. Properly designed price signals can encourage DERs to operate or locate where they deliver maximum value—for example, by reducing peak demand, deferring costly infrastructure upgrades, or cutting local emissions. Many states also aim to prioritize environmental justice communities (EJCs) by directing clean energy investments to areas historically burdened by pollution or underserved by traditional programs. Ensuring DERs can provide values at the right time and right location is critical to maximizing system-wide benefits, reducing overall costs, and advancing equity objectives in the clean energy transition.

Among these goals, states may choose their own prioritization. For example, a program with a limited number of eligible participants may de-prioritize the goal of managing cost shift and affordability with the knowledge that total incentive dollars collected to fund the program will remain small. In such a case, stronger price signals could be prioritized to ensure DERs deliver benefits to the grid. Conversely, if a state's immediate priority is to stimulate technology and process learning (e.g., early-stage battery storage), it might be willing to deprioritize near-term grid value until that technology becomes more widely adopted and cost-competitive. Or a program focused on ratepayer protection might enact stringent guardrails to limit rate increases or provide additional incentives for low-income households and other vulnerable populations.

This prioritization may evolve over time as well: a state may emphasize adoption to spur market transformation for a new technology before switching to a more measured approach to protect ratepayers once that technology becomes more established.

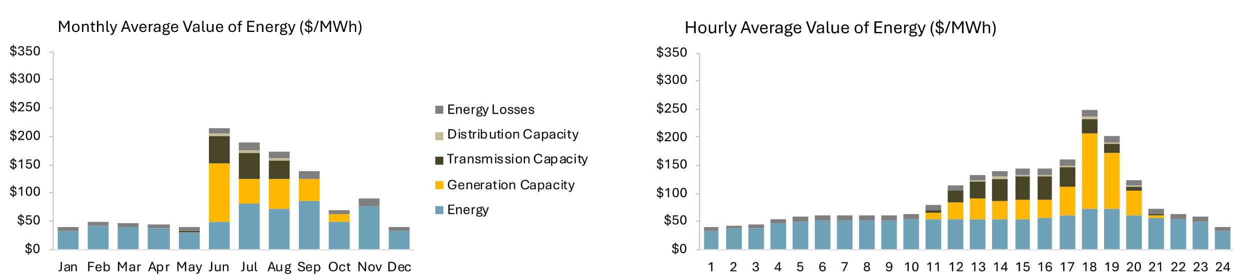
Any decision to prioritize one of these goals relative to the others should be well-informed. In this section, we describe a framework that, through evaluation of multiple cost-effectiveness tests, provides analytical context to this decision-making process.

2.1 Evaluation of DER Benefits

The first step in developing a compensation framework or cost-effectiveness tests to evaluate it involves identifying the benefits the compensation seeks to address. For the purposes of this analysis, the primary set of potential benefits comes in the form of costs that DERs can avoid for electric utilities and the ratepayers they serve, though other benefits not monetized through utility rates may also be considered. Avoided costs to utilities include components such as the avoided cost of energy, generation and utility infrastructure capacity, and monetized emissions reductions or renewable energy credits.

Each of these components carries some time dependence: energy prices fluctuate on an hourly basis throughout the year and from year-to-year; strain on electric grid infrastructure depends on load, which varies at the hourly or sub-hourly level; and emissions benefits vary depending on the marginal generating unit in each hour. Accordingly, the value that DERs can provide in each of these categories depends not only on the volume of energy or capacity the DERs offer but also the timing of when they offer it. Figure 7 illustrates the range of the resulting avoided cost benefits across different seasons and hours of the day.

Figure 7. Ameren territory monthly and hourly average avoided costs, 2025



Each of these avoided costs and other benefits associated with DERs provide context for the following compensation framework. The full range of benefits and methodologies for calculating each are described further in Section 3.

2.2 Compensation Framework Overview

As required by CEJA, the base rebate and additive services are designed to compensate DERs for the services they provide to the energy system and society that are not already covered by other mechanisms. Table 4 shows one framework of grid and societal values that each compensation mechanism is intended to address. Detailed information on NEM and ABP can be found in Section 2.4.

Table 4. Mapping of DER compensation programs to benefits

DER Value	Net Electricity Metering	Adjustable Block Program	Base Rebate + Additive Service
Avoided Energy	Yes		
Avoided Generation Capacity	Yes		
Avoided Monetized GHG/REC		Yes	
Avoided Transmission Capacity	Yes		
Avoided Losses	Yes		
Avoided Distribution Capacity	Depends*		Yes
Non-Monetized Benefits			Yes

**Whether Net Electricity Metering compensates distribution value depends on DER type and generation type. For example, NEM offers distribution credits to the amount of roof-top solar that is used to offset customer load. Community solar, on the other hand, does not receive distribution credits.*

It's important to recognize that compensating each value component separately does not guarantee that DERs are compensated appropriately or accurately as a whole. For example, while NEM is intended to reflect the energy and generation capacity value that DERs provide by offsetting the electric supply charge, the compensation offered by NEM sometimes exceeds the actual energy and capacity costs that DERs avoid. This misalignment can lead to overcompensation. To address this, it is critical to evaluate the total value of DERs relative to the total compensation provided. Only by looking at the entire compensation package can the state determine whether DERs are being fairly compensated—neither underpaid for their contributions nor overpaid at the expense of other ratepayers.

There are two main approaches that fulfill CEJA's requirements but differ in how they prioritize various objectives for DER adoption:

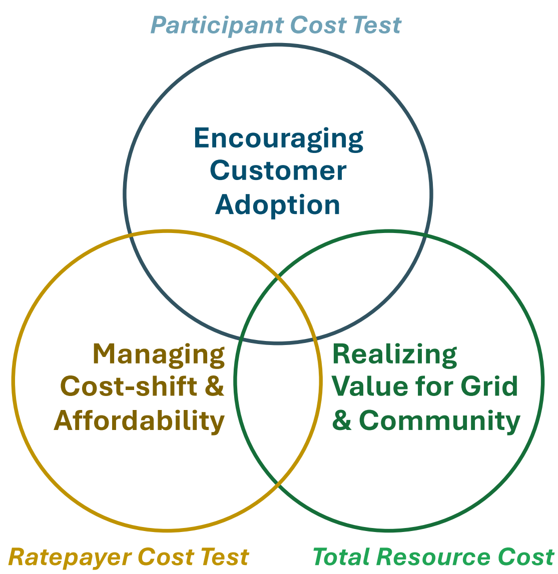
- **Component-Based Compensation**: This method calculates incentives solely from the specific value components not already captured by existing programs. It meets CEJA's directive that the base rebate should cover "system-wide grid benefits," while additive services should cover any remaining benefits. However, because it does not explicitly evaluate the impacts on broader objectives (e.g., cost-shift, affordability), nor fully compare all DER compensation and value, it may not fully capture the trade-offs among these priorities.

+ **Cost-Test-Driven Compensation**: This method uses cost-effectiveness tests to quantify the benefits and costs of a DER program from multiple perspectives. It then sets incentives only if a given DER meets certain cost-effectiveness thresholds. In doing so, it recognizes the full suite of benefits and compensation mechanisms that DERs may receive, allowing policymakers to balance the value DERs provide with ratepayer protection. By contextualizing the total compensation within the broader set of ratepayer and societal objectives, this approach helps ensure that DER investments are both beneficial and equitable for all stakeholders.

2.3 Benefit-Cost Tests

Building on the need to balance different objectives—encouraging adoption, managing cost-shifts, and realizing grid and community value—it is helpful to conduct benefit-cost tests when setting compensation for DERs. These tests, shown alongside the objectives they help to evaluate in Figure 8, provide a structured way to evaluate the quantifiable benefits and costs of a DER program from multiple perspectives. A benefit for one group of stakeholders can translate into a cost for another. Developing an equitable and efficient compensation framework thus requires balancing these diverse viewpoints to encourage DER adoption while minimizing unintended rate impacts.

Figure 8. Incentive goals and corresponding cost tests



Common benefit-cost tests used in utility customer program evaluation include:

+ **Total Resource Cost Test (TRC+)**: This test assesses statewide benefits and costs, taking the perspective of all residents in Illinois. It captures economic, environmental, and societal impacts that arise from investments in clean energy. Illinois already uses the TRC for many customer-facing programs, including energy efficiency efforts. Throughout this report, we refer to a "TRC+" to emphasize that benefits considered in the test may not match a strict interpretation of the TRC test in which only elements that translate most clearly to dollars are included. Instead, benefits included in the TRC+ can be adjusted by the state to reflect priorities that may be more commonly seen in a societal cost test.

- **Ratepayer Impact Measure (RIM)**: This test evaluates the financial effects on all ratepayers. It helps answer the question: "What happens to overall rates if a customer adopts a DER?" The RIM results also help inform whether and how the incentives received by a DER customer lead to cost-shifts to ratepayers who do not or cannot adopt a DER.
- **Participant Cost Test (PCT)**: This cost test captures all benefits and costs that accrue directly to customers who install a DER. It helps answer questions like: "Does it make financial sense for a household or business to invest in rooftop solar, battery storage, or another DER?"

No single test can fully capture the complex trade-offs among customer adoption, ratepayer equity, and broader societal or environmental goals. Hence, evaluating all three tests helps reveal where over- or under-compensation may occur and whether the program strikes the right balance between promoting DER growth and protecting non-participants. Such a holistic view ensures that policymakers understand not only the value delivered by DERs but also how best to align compensation with CEJA's broader goals—while mitigating the risk of cost-shifts.

Some stakeholders contend that if all customers have the opportunity to install DERs, any resulting rate increases simply reflect personal choice rather than a cost-shift. However, *true* equity of access is seldom the reality. Factors like home ownership, credit scores, income levels, time constraints, and lack of trust in utility programs can present *practical* barriers for many customers. Consequently, even if a program is theoretically open to all, it does not ensure that all can participate on the same terms, and it remains important to understand RIM test results.

Moreover, even in a hypothetical scenario where every customer participates, there is still value in understanding how avoided costs stack up against incentives paid to DER owners. In that situation, net costs would reveal inefficient spending of ratepayer dollars, as ratepayers would be paying more to fund their own incentives than the savings they would see. Cost tests evaluate programs against a standard, but not against other options to achieve the same goals, so a negative RIM result should be a cue to examine if other types of programs can achieve similar objectives with more efficient spending.

2.4 Existing Compensation Mechanisms

Any added DER incentive mechanism should recognize its context to ensure a lack of double-counting and to understand how adding an incentive will alter customer adoption and dispatch behavior. Customers who install distributed generation or distributed energy storage may receive incentives from the Adjustable Block Program and/or Net Electricity Metering bill credits in addition to the Base Rebate and Additive Services incentives discussed in this report.

2.4.1 Adjustable Block Program (Illinois Shines and Solar for All)

The Adjustable Block Program (ABP), also known as Illinois Shines, is a state-administered solar incentive initiative managed by the Illinois Power Agency (IPA) to support the development of new photovoltaic projects. It aims to support the development of new photovoltaic projects by offering Renewable Energy Credit (REC) contracts to solar developers, who in turn can pass these incentives on to customers.

A separate program, *Illinois Solar for All*, offers higher REC payments than the standard ABP and serves income-eligible households, nonprofit organizations, and public facilities. All Illinois residents, commercial and industrial customers, and public entities (such as public schools) are eligible to participate in these programs.

For simplicity, the remainder of this report refers to Illinois Shines and Illinois Solar for All collectively as the ABP. While treated as a single program name, different customer segments receive different REC incentives based on their eligibility criteria. Overall, the ABP is available for two types of solar projects:

+ **Distributed Generation (DG):** These systems are located on the customer's property, either on rooftops or ground-mounted, and generate electricity for on-site use and export to the grid.
+ **Community Solar (CS):** Community solar projects are larger, centrally located solar installations that supply electricity to multiple customers who may not be able to install solar panels themselves. This option is ideal for renters or homeowners for whom installing solar panels is impractical or not cost-effective. Through community solar, many customers can subscribe to a single, large solar project and offset their electricity use and costs with a share of the electricity generated by the system. While the community solar project may be located far from the customer, it must be within the same utility service territory.

The ABP compensates eligible participants through payments for RECs, where each REC represents the environmental benefit of generating one megawatt-hour (MWh) of solar power. REC prices, expressed in dollars per MWh, vary depending on the type of project (DG or CS), system size, location within utility territories, and customer classification. Each program year, the Illinois Power Agency establishes specific REC prices based on the capacity available within each project category.

REC prices are calculated using Illinois Power Agency's REC price model. The model is designed to calculate the revenue and incentive levels required for typical distributed solar or community solar projects to meet investment thresholds. The REC price was calculated such that the total revenues received by solar projects are enough to cover the project's expenses, debt obligations, and meet investors' minimum return requirements.[4] More specifically, the REC price is calculated to cover the

[4] https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/appendix-d-rec-pricing-model-description-2022-long-term-plan.pdf

gap between the financial requirement of distributed solar projects and existing compensation these projects receive.

This “missing money” style method for determining the REC price means that any change to the current incentives for solar has the potential to change the calculated REC price. For example, an increase to the Base Rebate for distributed solar would decrease the gap between the financial requirement and existing compensation, resulting in a smaller REC price.

2.4.2 Net Electricity Metering

Under Illinois law, investor-owned utilities, including ComEd, Ameren, and MidAmerican, are required to offer net electricity metering (NEM) for renewable energy systems that are designed to offset a household's energy usage. Net metering allows customers to receive bill credits based on their energy consumption after distributed generation. Initially, NEM provided customers with roof-top solar full retail rate credits for all energy generated, meaning that both electricity self-consumed on site and energy exported to the grid were compensated at the utility's retail rate.

The full retail rate consists of multiple components, including:

- **Electric Supply Charge**: This charge reflects the cost per kilowatt-hour (kWh) for the electricity consumed by the customer. This charge typically covers the cost of resource generation to supply both energy and capacity.
- **Transmission Service Charge**: This charge is designed to allow the utility to recover costs associated with transmission service.
- **Delivery Service Charge**: This component accounts for the cost of delivering electricity from the transmission system to the customer’s location.
- **Purchase energy adjustment**: This is a monthly charge or credit that adjusts the cost of electricity to match the actual cost of electricity supplied to customers. This component ensures that customers pay no more or less than the actual cost of electricity.

With the passage of CEJA, Illinois NEM policies will change for customers who interconnect renewable energy systems after December 31, 2024. After this date, customers will be eligible for a portion of the retail rate credits for any excess energy sent back to the grid, rather than the full retail rate previously available.

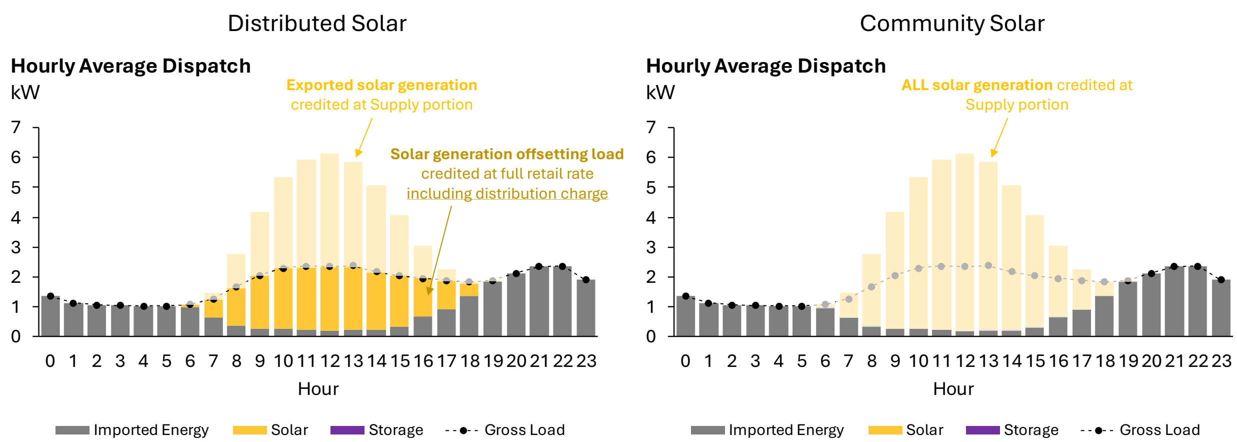
Table 5 summarizes the NEM policies for customers who interconnect renewable systems after December 31, 2024. Self-consumption refers to the portion of electricity generated by the customer that is used directly on-site to meet their own energy needs during the monthly billing period, up to the total amount of their energy usage. Exports refer to any excess electricity generated by the customer that exceeds their on-site energy needs during the monthly billing period. Note that retail rates, and by extension, retail rate credits under NEM, cover transmission and distribution line losses.

Table 5. Solar compensation under NEM

Solar type	Self-Consumption	Exports
Distributed Solar	Full retail rate	Electric supply charges, transmission service charges and purchased energy adjustment portions of the retail rates
Community Solar	Electric supply charges, transmission service charges and purchased energy adjustment portions of the retail rates	

Figure 9 illustrates how distributed solar and community solar receive compensation under NEM after December 31, 2024.

Figure 9. Credit schemes for solar generation dispatched to the grid starting in 2025



One important aspect of NEM to note is how the credit for on-site consumption depends on a customer's retail rate. Rates that mirror a utility's cost to serve load well value distributed generation more accurately, while rates that prioritize simplicity over cost reflectiveness will value distributed generation less accurately. For example, a customer on a flat volumetric rate can significantly reduce their contributions to transmission-, distribution-, and program-related costs, without necessarily impacting the costs themselves, which are driven by factors other than volumetric consumption.

NEM highlights a disconnect between the avoidable cost of new distribution or transmission infrastructure and other embedded distribution or transmission system costs, which include historical system costs and future costs that cannot be avoided. Distribution avoided costs are smaller than the distribution component of rates, which recovers embedded costs. Also, only a small number of hours each year are relevant for avoidable costs, but current rates often collect embedded costs over all hours of the year. Therefore, a DER that avoids distribution and transmission rates is compensated at a higher rate than the avoided costs associated with these elements and receives this compensation regardless of alignment with avoided cost critical hours.

2.5 DER Focus

This report focuses on compensation design for distributed solar—both behind-the-meter (BTM) solar and community solar—and energy storage, as these technologies are the most commonly adopted by customers. Other DERs highlighted in CEJA, such as demand response and electric vehicles (EVs) equipped with managed charging, can be viewed as more specialized variants of energy storage. Demand response and managed EV charging offer comparatively less flexibility than lithium-ion batteries, as the enrolled devices and EVs must fulfill operational purposes beyond simply reducing load. However, DR and EV charging represent valuable opportunities as "free" sources of flexibility, meaning, opportunities to take advantage of technologies already adopted by customers to create flexibility at potentially low incentive cost. We return to this idea as we discuss an Additive Services proposal in Section 5.1

In the series 1 workshops, stakeholders have identified a wide range of DERs, including wind turbines, biofuel, fuel cells, microturbines and microgrids. The impact of these technologies on the electric system can be easily calculated using the avoided cost framework. To perform a comprehensive analysis on the benefits and costs of these technologies from the participant, ratepayer and societal perspectives, additional data need to be gathered. For example, the upfront costs of these technologies should be collected in order to compare their costs vs benefits from customer and societal perspectives.

Ultimately, grid services should be valued in a technology-agnostic way. A kWh of energy provided to the grid in a given hour and at a given location is just as valuable whether it comes from solar, battery energy storage, vehicles feeding power back onto the grid, aggregated loads, or any other solution that aligns with CEJA's vision for decarbonization. However, this technology agnosticism breaks down when we evaluate expected performance of a DER over its lifetime: a non-dispatchable technology will be far less likely to provide a kW to the grid when needed than a dispatchable technology, and different dispatchable technologies will have different levels of dependability in response to program signals. Accordingly, we develop avoided costs that depend only on the grid, but a benefit-cost dispatch model that evaluates expected performance of specific customer/DER use cases.

2.6 DER use cases for evaluation

To understand DER dispatch behavior, hourly value to the grid, and the stack of compensation mechanisms available to customers in different situations, we identify a set of use cases. Each use case combined a customer type with a DER type, in combinations that we select to ensure representation of a range of customers and DERs. The full list of use cases appears in Table 6.

All instances of rooftop solar are assumed to be behind-the-meter (BTM), meaning that the energy generated by the solar first offsets any simultaneous customer load before excess is exported to the grid. We note that we assume multifamily residents do not have access to rooftop solar but can participate in Community Solar. We do include multifamily residents as potential BTM energy storage owners, but we do not include them as potential solar+storage participants since their on-site storage and remote solar could not be co-located behind the meter.[5] DER performance would not differ for Low and Middle Income (LMI) customers, but we include use cases to highlight this group based on the additional federal and state incentives they receive. Though Community Solar installations may be connected at the distribution or transmission level, these use cases assume distribution level connection, which enables them to provide value to the distribution system. We assume that community solar would be eligible for the $250/kW Base Rebate, while all rooftop solar would be eligible for the $300/kW Base Rebate.

Table 6. DER use cases modeled

Use Case #	Utility Territory	Customer Type	LMI Status	DER
1	Ameren	Residential	-	Rooftop Solar
2	Ameren	Residential	-	Community Solar
3	Ameren	Residential	-	Solar+Storage
4	Ameren	Residential	-	Standalone Storage
5	Ameren	Residential	Y	Rooftop Solar
6	Ameren	Residential	Y	Solar+Storage
7	Ameren	Residential	Y	Standalone Storage
8	Ameren	Medium Office	-	Rooftop Solar
9	Ameren	Medium Office	-	Solar+Storage
10	Ameren	Medium Office	-	Standalone Storage
11	Ameren	Primary School	-	Rooftop Solar
12	Ameren	Primary School	-	Solar+Storage
13	Ameren	Primary School	-	Standalone Storage
14	ComEd	Residential	-	Rooftop Solar
15	ComEd	Residential	-	Community Solar
16	ComEd	Residential	-	Solar+Storage
17	ComEd	Residential	-	Standalone Storage
18	ComEd	Residential	Y	Rooftop Solar
19	ComEd	Residential	Y	Solar+Storage
20	ComEd	Residential	Y	Standalone Storage
21	ComEd	Medium Office	-	Rooftop Solar
22	ComEd	Medium Office	-	Solar+Storage
23	ComEd	Medium Office	-	Standalone Storage
24	ComEd	Primary School	-	Rooftop Solar
25	ComEd	Primary School	-	Solar+Storage
26	ComEd	Primary School	-	Standalone Storage

For each use case, we use a simple set of rules to define DER sizing:

- Annual customer load is set to a representative load shape by customer type based on location, housing or commercial type using NREL's ResStock and ComStock load directory

[5] Virtual net metering could make this possible, but we do not consider it in this study since community solar is credited on an all-export basis in Illinois. It could also be possible within multifamily buildings that have rooftop solar, but this arrangment is well-captured by the single-family solar+storage use case.

- Solar is sized to cover 100% of total custom er load over the course of the year
- Storage in a solar+storage configuration is sized to 50% of the solar capacity, with a duration of 2.5 hours for residential applications and 2 hours for non-residential application.[6]
- Standalone storage capacity is sized using the same method as solar+storage configurations, as if there were a solar array designed to over 100% of annual load (so standalone or paired energy storage will have the same capacity for a given customer). Duration for standalone systems is assumed to be 4 hours.

The goal for this set of selected use cases is to cover key dimensions of variability: Different utilities will have different rates and be representative of different regions. Different customer types are eligible for different existing Base Rebates, receive different ABP incentives, have different load characteristics, and have unique rates. LMI sites are assumed to receive higher ITC incentives and have different load characteristics. And different DERs have access to different incentives and have different operating characteristics. While there are additional dimensions in which customer attributes and DER dispatch can vary, we identified these dimensions as the most valuable to highlight for incentive design.

[6] Storage durations were selected based on available cost data from NREL ATB 2024

3 DER Benefits

We divide DER benefits into two broad categories: monetized benefits and non-monetized benefits. Monetized benefits are equivalent to avoided costs, which represent the expenses that utilities or load serving entities (LSE) would have otherwise incur a given DER resource is absent. These benefits are deemed "monetized" because they impact utility revenue requirements and therefore the electric rates for ratepayers. In addition to direct monetary costs, DER may provide "societal" values such as benefits to the environment or public health. These "non-monetized" benefits do not impact utilities' revenue requirement or LSE's procurement costs but are valuable for the broader society. Many non-monetized benefits even have quantifiable dollar impacts on state residents (such as reliability improvement for a host customer) but these benefits remain "non-monetized" in that they do not impact the utility revenue requirements.

Quantifying avoided costs can take multiple perspectives. One common approach is to isolate each component of the utility's revenue requirement that would be impacted by DERs and to quantify these components. We followed three principles in developing the avoided costs:

- **Marginal**: The marginal cost framework calculates the incremental change in utility revenue requirements due to customer load increase or decrease. While many utility costs are already sunk—reflecting past or inevitable future investments—a portion of forward-looking system costs can still be avoided by reducing or shifting load in specific hours. This framework mirrors how supply-side resources are evaluated, whereby their marginal contribution to the system is calculated based on the incremental capacity, energy, and delivery costs they either incur or offset. Overall, these marginal costs are intended to serve as implicit and explicit price signals to achieve Illinois's energy, reliability and GHG goals.
- **Long-term**: The value of DERs should be assessed over their full lifespan to fully account for their long-term impact on the evolving grid, especially under the CEJA. CEJA mandates that the base rebate reflect the system-wide services provided by DERs for a minimum of 25 years. Thus, avoided costs should be developed with a time horizon of at least 25 years, aligning with the expected transformation of the grid under CEJA.
- **Technology agnostic**: Since avoided costs are intended to evaluate a variety of DER technologies, they must remain technology neutral. The most effective way to achieve this is by generating hourly avoided cost streams in $/MWh. These can be applied to any DER's generation or dispatch profile. Hourly granularity is critical, as it reflects the time-varying nature of DER generation and dispatch, as well as the time-sensitive operation of the grid.

Following the above principles, we developed hourly avoided costs by component for the years 2025 to 2050. Total avoided costs, which sum all avoided costs components for each hour, can be multiplied by various DER generation or dispatch shapes to quantify avoided costs or costs of each DER, depending on whether the DER is load reducing or load increasing. The sections below describe the methodology of calculating each avoided cost component.

3.1 Distribution Avoided Costs

DERs have the potential to avoid costs for the distribution system by reducing the demand for energy, or even providing energy, during times when the local hardware may be most constrained. As a result, these DERs can mitigate or defer the need for investments that would take place specifically to support increased capacity of the system in specific areas where load is increasing to support electrification or other demands.

While this iteration of the avoided cost valuation seeks to determine a system-wide applicable value for distribution capacity, the avoided cost of distribution is in fact both highly dependent on the location and time that a resource is available. This is because most of the distribution system is not capacity constrained at any given point in time, and adding capacity where or when there are no constraints to alleviate does not provide any value. In Section 6.1.1, we explain how we hope improvements in future data can improve upon the system-wide valuation approach used here for this version 1.0 of the analysis.

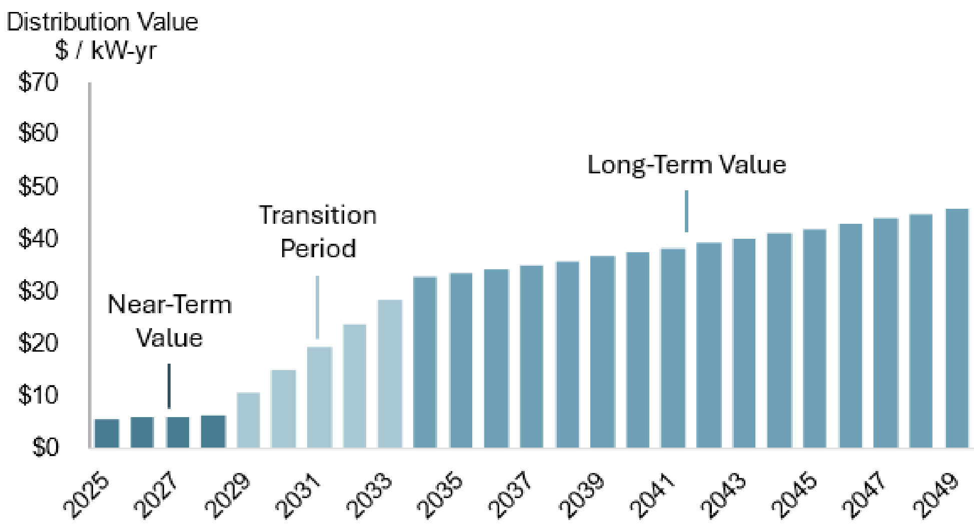
For the purposes of this analysis, we take the marginal distribution cost values determined for specific areas of need and spread them across the Illinois service territory of each Ameren and ComEd. This results in a systemwide average avoided cost value rather than location-specific avoided costs which would be very high in some individual areas of need and near zero in other parts of each utility's service territory.

We do address the time-varying aspect of distribution avoided cost value by allocating costs across different hours of the year when the system is expected to experience the greatest strain. These hourly values can later be compared to a DER's expected hourly resource profile to estimate a total annual distribution value. The specific application of this approach, referred to broadly as a Peak Capacity Allocation Factor (PCAF) approach, is detailed further in Appendix C.

In valuation of distribution avoided costs there is frequently a degree of tension between efforts to fully capture and support both the long-term and marginal views. Because distribution planning is typically approached looking 3-5 years in advance and there is a lower degree of confidence in longer term forecasting, the more detailed marginal distribution cost studies that utilities undertake are unlikely able to capture the long-term, and top-down methods of estimating costs over the longer term tend to lack the resolution for isolating what costs are truly marginal.

To address this tension in the available data and consider input provided by stakeholders throughout the workshop series, we have approached the valuation of distribution avoided costs by combining both a top-down and bottom-up view. This balance is applied by splitting the 25-year anticipated life of DERs into three segments. The near-term, or first four years of a DER's expected life, are valued using a bottom-up approach, as described below. Years 10-25 of the DER's life are valued using a top-down view, and years 5-9 provide a transition period with gradual ramp up between the bottom-up and top-down values. Each year, distribution avoided cost values are additionally escalated at the applicable utility's nominal distribution cost escalation rate, as provided by the utilities in the cost-of-service study workpapers. Figure 10 provides an example of the resulting year-by-year pattern for total distribution capacity value. It should be noted that this value represents the maximum benefit a DER could provide - averaged across locations on the distribution system - if it were to provide energy or avoid capacity need for the distribution system in *all* hours of need. A DER which is able to provide capacity for some portion of these hours would thereby generate a derated portion of this value.

Figure 10. Maximum Potential Distribution Value (ComEd, DER Installed 2025)



3.1.1 Near-Term Distribution Value

We approach the near-term distribution value relying primarily on the bottom-up marginal cost of service studies performed by the utilities for their refiled grid plans. We reviewed the methodologies applied by utilities in these studies, and while there are areas for potential future improvements, we largely consider these approaches to be appropriate for this purpose. It should be noted that at the time of this analysis, the refiled grid plans and final cost of service values have not yet been approved by the ICC, and the Joint Solar Parties have filed complaints about utilities' findings. Given this, so long as the general methodology remains the same in the final order, we would ultimately recommend relying on whatever final distribution cost of service values are in fact approved when applying those to this bottom-up approach.

3.1.2 Long-Term Distribution Value

For the long-term distribution value, we rely on public FERC Form 1-filings and utility historical peak loads to provide a top-down cost estimate. We isolate costs to the 'plant and equipment' category from FERC filings as a rough estimate for the portion of costs that are most tied to incremental capacity need for the distribution system. This category does inevitably also include several types of costs which are not fully marginal or avoidable due to the adoption of DERs but provides a sense of some of the longer-term investments that the utilization of DERs may be able to mitigate. This top-down approach has the added benefit of being much more transparent in application and easier to understand for outside parties.

The output values from each approach are depicted in Table 7 along with maximum potential net present value that a DER may be able to achieve over 25 years. Further detail on the application of the bottom-up and top-down approaches and their application is provided in Appendix B.

Table 7. Distribution Capacity Values by Utility (2024 $/kW-yr)

	Near-Term Distribution Value	Long-Term Distribution Value
Source	*Utility Cost of Service Studies*	*FERC Form 1 and Refiled Grid Plans*
Ameren	$9.43	$34.30
ComEd	$5.54	$27.98

3.2 Avoided Transmission

DERs may also shift or reduce load further upstream from the distribution system, resulting in avoided or deferred costs for transmission capacity. The three guiding principles discussed for evaluating avoided costs as marginal, long-term, and technology-agnostic apply equally to the transmission system, though the nature of transmission planning in Illinois poses some challenge to isolating for marginal long-term costs.

Ameren Illinois and ComEd each receive transmission service from a regional transmission organization or operator (RTO). Ameren is served by Midcontinent Independent System Operator (MISO), while ComEd is served by PJM. The structures of each RTO and their relationships with the respective utilities vary slightly, but in each instance the RTO is largely responsible for long term transmission planning and coordinating between transmission assets that are frequently developed, owned, or operated by a collection of smaller entities: Ameren and ComEd. As Ameren and ComEd rely on this shared transmission system, they pay the RTO for their usage based on a dollar-per-kilowatt-year network transmission service (NTS) rate. For the purposes of this analysis, these rates, presented for each utility in Table 8, are used as an upper bound estimate of transmission capacity avoided costs. These values are allocated to specific hours of transmission need using the PCAF approach described in Appendix C.

Table 8. Transmission Capacity Values by Utility (2024 $/kW-yr)

	2024 Network Transmission Service Rate
Source	*MISO and PJM*
Ameren	$80.00
ComEd	$39.80

It is important to note that the network transmission service rates are driven by gross annual transmission expenses incurred by the RTOs, plus a rate of return. While these rates are expressed and charged to the utilities in terms of dollar-per-kilowatt-year, these expenses include several categories which are embedded or not explicitly capacity-driven. Therefore, these rates are more attuned to average cost for the system rather than marginal costs. In the very short term, if Ameren or ComEd's coincident peak load were to increase or decrease by a certain amount, then the difference in their required payment to the RTO could be calculated by multiplying that amount by the listed NTS rate. However, the actual expenses incurred by the RTOs would be expected to increase or decrease to some lesser degree, because the embedded costs have not changed with the capacity. The next time the NTS rate is evaluated, that rate itself would be updated to more appropriately reflect the actual impact on transmission costs. Because of this, each RTO independently noted that the NTS rate is not an appropriate indicator of their capacity-driven marginal costs.

After extensive discussions with both utilities and RTOs, these organizations indicated to E3 that they were not able to provide a more accurate, specific marginal cost for transmission capacity at this time. Both MISO and PJM have stated that they were interested in further exploring this value through collaborative future transmission planning with the Illinois utilities.

3.3 Other Avoided Costs

Similar to how distribution and transmission system costs may be mitigated, DERs can reduce load or shift load from periods with grid constraints to times of abundant energy supply. By doing so, DERs have the potential to avoid costs associated with procuring energy and generation capacity. Given that CEJA sets a state climate policy that will achieve 100% clean energy by 2050 and phase out coal generation as well as gas plants, DERs with zero emissions can also help support these goals by avoiding the infrastructure costs that would occur to meet these goals. This section describes the calculation of the following avoided cost components:

+ Avoided cost of energy
+ Avoided cost of generation capacity
+ Avoided cost of GHG
+ Avoided cost of line losses

While these components have generally been addressed by NEM and the Adjustable Block Program (ABP), it is important to quantify them for use in cost-effectiveness tests. By comparing the total avoided costs with current DER compensation levels, we can assess the impact of DERs on ratepayers. Additionally, evaluating the costs of DERs against these avoided costs helps determine whether a particular DER is an economically efficient option to achieve the state's energy, capacity, and GHG reduction objectives.

As previously mentioned, Illinois is part of the MISO and PJM Interconnection wholesale markets. Ideally, avoided costs related to resource generation should come from CEJA-compliant long-term resource plans from MISO and PJM. However, PJM doesn't have a long-term policy compliance resource plan, and while MISO published a report on its long-term resource expansion plans, they cannot provide data due to confidentiality issues.

Given the absence of public long-term RTO data, we used Cambium data developed by NREL as an alternative source for resource generation related avoided costs, including energy, generation capacity, GHG and losses. Cambium datasets contain modeled hourly emission, cost, and operational data for a range of possible futures of the U.S. electricity sector through 2050. Cambium provides data in several levels of locational granularity. We used the data at the Generation and

Assessment (GEA) Region levels, which are shown in Figure 11. As indicated by the figure, we used PJM West as the proxy to ComEd territory and MISO Central as proxy to the Ameren territory.

Figure 11. Cambium data organization by Generation and Assessment region

Cambium models multiple scenarios with various potential futures of GHG policy, fuel prices and technology advancement. We used the MISO's Long-Range Transmission Planning (LRTP) scenario Future 2A as the reference to selecting the corresponding scenario in Cambium. MISO LRTP Future 2A performs a resources expansion analysis for MISO for 2022-2042. Future 2A meets 100% of announced state and utility decarbonization goals, including CEJA, and achieves 95% emission reductions of the 2005 level by 2042. Using MISO Future 2A as the reference, we selected the Cambium 95% Decarbonization by 2050 scenario. This Cambium scenario reflects electric sector policies as existed in September 2023 and applies a national electricity sector decarbonization that linearly declines to 5% of 2005 emission on net by 2050.

Figure 12 compares the installed capacity between MISO LRTP Future 2A and Cambium 95% by 2050 scenario. These figures show installed capacity for the entire MISO. Using 2040 as the reference year, MISO installed capacity in Cambium is 15% higher than MISO Future 2A. The differences in resource portfolios between the two sources can be attributed to several factors. One of them is the load assumption whereby Cambium forecasts higher load growth than MISO Future 2A (Figure 13). Other differences between the two sources may include resource capacity accreditation, peak load, fuel prices and resource costs.

Figure 12. Future installed capacity in MISO between MISO LRTP Future 2A and NREL Cambium 95% Decarbonization by 2050

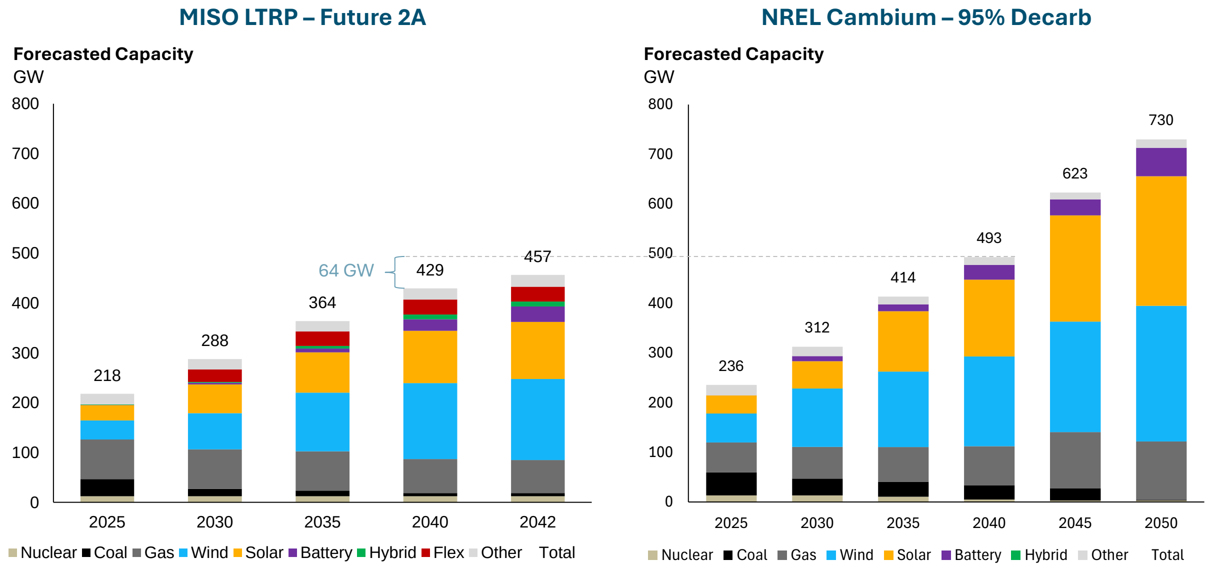
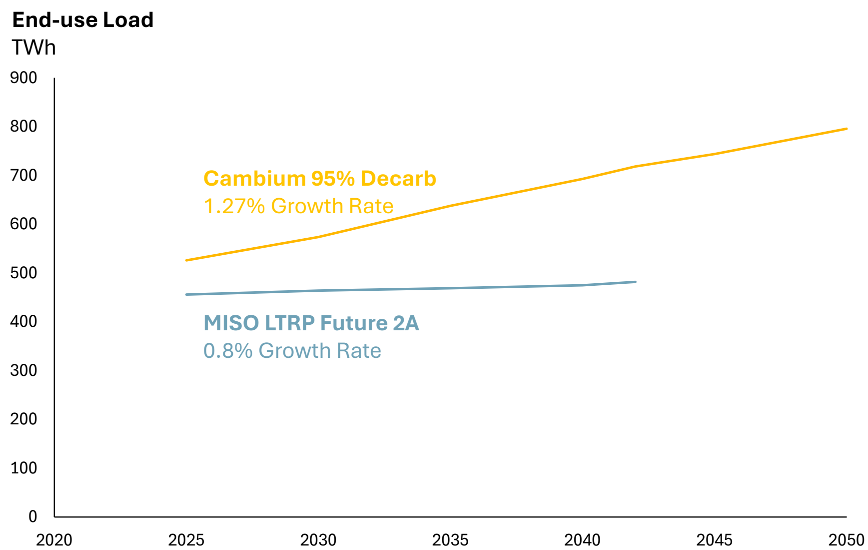
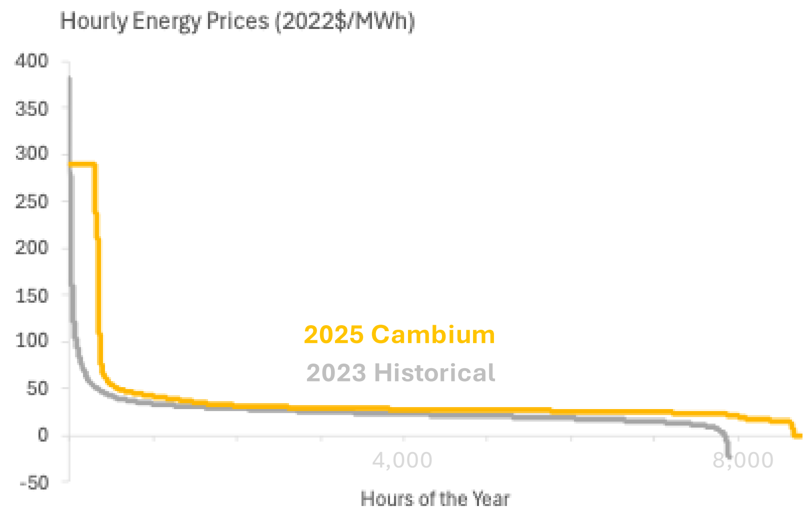


Figure 13. Annual load in MISO between MISO Future 2A and NREL Cambium



Cambium provides hourly data for every 5 years from 2025 to 2050. Figure 14 compares Cambium MISO central hourly energy prices in 2025 with EIA MISO historical day-ahead energy prices at the Illinois hub. Cambium energy prices are similar to MISO historical prices in most hours except for the top scarcity hours. Cambium energy prices are capped at $283/MWh, which is the short-run marginal energy cost of the most expensive combustion turbine nation-wide, while MISO historical prices went up to $400/MWh.

Figure 14. Cambium MISO central marginal energy costs vs MISO historical day-ahead energy prices at Illinois hub



We calculated the following avoided cost components using NREL Cambium Data:

- **Avoided Energy Costs**: Cambium produces hourly short-run marginal costs for providing energy in $ per MWh of busbar load. These costs are conceptually analogous to day-ahead locational marginal prices. These marginal costs include the effects of generator short-run marginal costs, transmission losses, and transmission congestion. In scenarios with national carbon constraints, such as the one used in this analysis, these hourly marginal costs also include GHG shadow prices. These GHG shadow prices reflect the marginal costs of reducing GHG emissions under specific emission constraints. As a result, the hourly energy costs from Cambium represent both avoided energy costs and avoided GHG costs.
- **Avoided Generation Capacity Costs**: The calculation of hourly avoided generation capacity costs consists of two steps:
    a. Annual capacity costs. Cambium published annual marginal generation capacity shadow prices, which indicate the $/MW-year marginal cost for obtaining additional capacity. Several decision variables impact the values of shadow prices, including the cost of new generation capacity, new transmission capacity and delayed retirement. We grossed up the shadow prices by the Planning Reserve Margin (PRM) to represent the cost of capacity to achieve the desired level of resource adequacy.
    b. Hourly Allocation of Annual Costs. To allocate the annual shadow prices to hourly values, we used the top net load hours reported in Cambium. The threshold of the net load hours is set by the lower of the net load during the 101st greatest net-load hour or 95% of the annual peak net load.
- **Avoided GHG**: As noted above, Cambium's marginal energy costs already incorporate GHG emission costs. Therefore, no separate calculation is needed for avoided GHG costs.
- **Avoided Losses**: Due to line losses occurring along the distribution and transmission systems, any given level of energy or capacity need present at the customer meter will

require a greater level of energy and capacity to be available upstream. To reflect this, we adjusted the energy (including GHG) and generation, transmission, and distribution capacity costs upward according to the losses expected between each resource and the end customer.

Distribution capacity values are adjusted upward based on the estimated distribution line losses, while generation and transmission capacity values are each adjusted upward by both distribution and transmission line losses. Energy (including GHG) costs are similarly adjusted upward by both distribution and transmission line losses, but with these losses explicitly split out and included as a separate avoided cost component.

a. Distribution line losses: Cambium includes both average and marginal distribution loss rates. The ratio of marginal to average distribution loss rates as estimated by Cambium is 1.5. Ameren provided marginal distribution loss rates in their distribution cost of service study, which were similarly equivalent to their average losses multiplied by 1.5, so these Ameren-provided marginal loss rates were used. ComEd was only able to provide an average distribution loss rate, so we applied the 1.5 ratio to scale up ComEd's average rates to an estimate of marginal distribution line losses. These marginal distribution losses based on ComEd's provided averages were used in this study.
b. Transmission line losses: For transmission losses, only average transmission loss data was available from Cambium. Consistent with the calculation for distribution losses, we applied a 1.5 ratio to scale the average transmission loss rates to marginal transmission loss rates.

Table 9. Distribution loss factors

	Average Dx Loss	Marginal Dx Loss	Ratios between Marginal and Average Loss	Average Dx Loss	Dx Loss for Avoided Costs
Source	*Cambium*	*Cambium*	*Calculated*	*Utility*	*Calculated*
ComEd	3.6%	5.4%	1.5	4.6%	**6.9%**
Ameren	3.6%	5.4%	1.5	8.7%	**13.0%**

Table 10. Transmission loss factors

	Average Tx Loss	Tx Loss for Avoided Costs
Source	*Cambium*	*Calculated*
ComEd	0.9%	**1.4%**
Ameren	1.2%	**1.8%**

3.4 Total Avoided Costs

Figure 15 through Figure 18 illustrate monthly and hourly average avoided costs for Ameren and ComEd. Overall, the data show that avoided costs—ranging from $50 to $300 per MWh (or $0.05 to $0.30 per kWh)—are significantly lower than current retail rates. Retail rates in Illinois recover a variety of fixed and indirect costs (e.g., infrastructure, administration, and policy-driven program costs) that are not directly offset by DER generation. As a result, DERs can only avoid a subset of total costs that utilities and ratepayers incur.

Among the individual components, generation capacity stands out as the largest contributor to avoided costs, but it accrues value in relatively few hours each year—often during system peaks or in stressed grid conditions. In contrast, energy avoided costs apply to every hour, reflecting the ongoing need for electricity supply that DERs can partially displace. However, as the grid incorporates more renewables under decarbonization goals, energy costs become increasingly time-variant, with periods of near-zero marginal costs when wind or solar production is abundant. Distribution avoided costs are lower in the near term and higher in the long term, mainly due to the shift from a bottom-up to a top-down approach. Avoided line losses have been embedded in each avoided cost component.

Figure 15. Ameren territory monthly and hourly average avoided costs, 2025

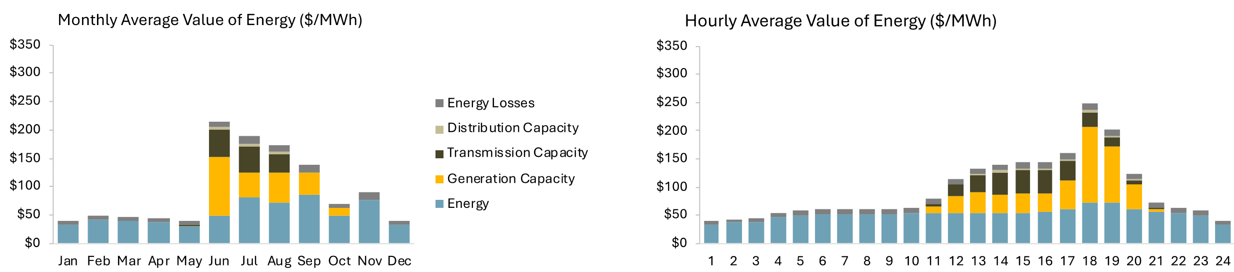


Figure 16. Ameren territory monthly and hourly average avoided costs, 2050

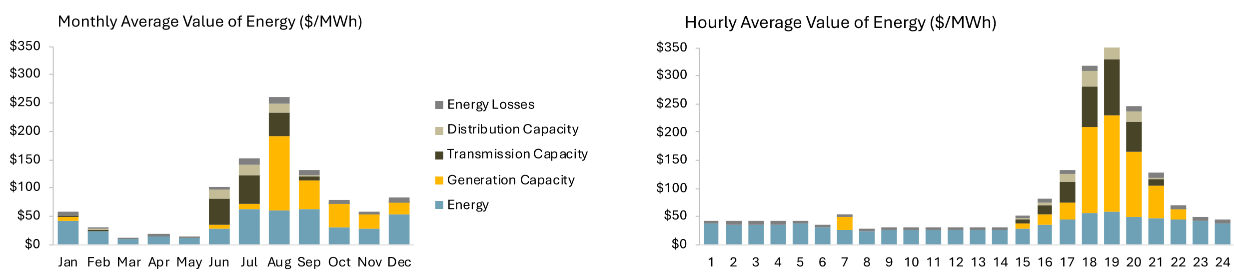


Figure 17. ComEd territory monthly and hourly average avoided costs, 2025

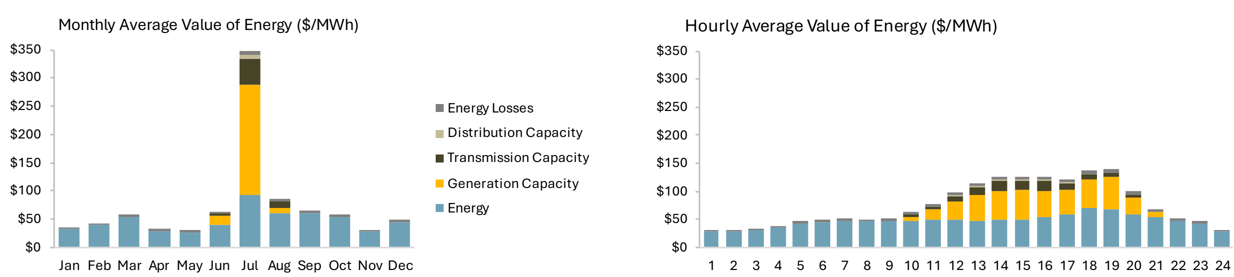
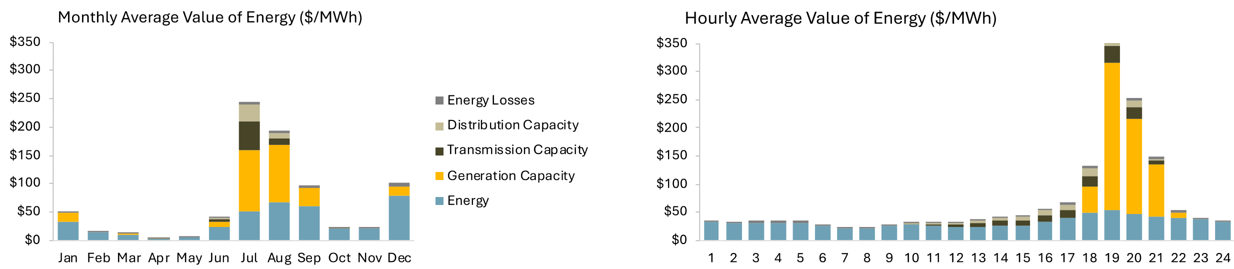


Figure 18. ComEd territory monthly and hourly average avoided costs, 2050



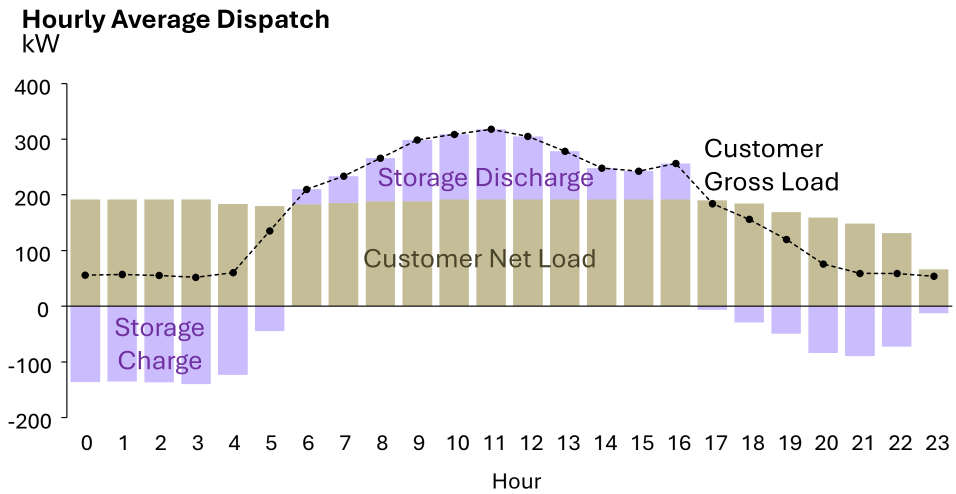
3.5 Bill savings

Both distributed generation and distributed energy storage have the ability to reduce customer bills, though the mechanics of this bill reduction may depend on the DER type and the customer billing rate. In the case of rooftop solar, bill savings stem from NEM. Under NEM, customers receive bill savings at their full retail rate for offsetting their onsite load with solar generation, and they receive bill savings at a reduced rate for exporting generation back onto the grid. For community solar, all solar production is viewed as export since the customer is not located behind the meter with the solar array. Savings from each of these configurations are calculated by looking at the difference between electric bills with and without the DER generation.

Energy storage has more limited opportunities to reduce bills. Since storage does not generate energy, it cannot create bill savings by reducing load. In fact, due to round trip efficiency losses, cycling storage will always increase customer load overall. But the dispatchability of energy storage enables it to reduce bills by shifting consumption to avoid or reduce time-dependent bill components. This dispatch may take the form of load flattening to reduce demand charges, load shifting to increase self-consumption of solar generation, or arbitrage of time-varying rates.

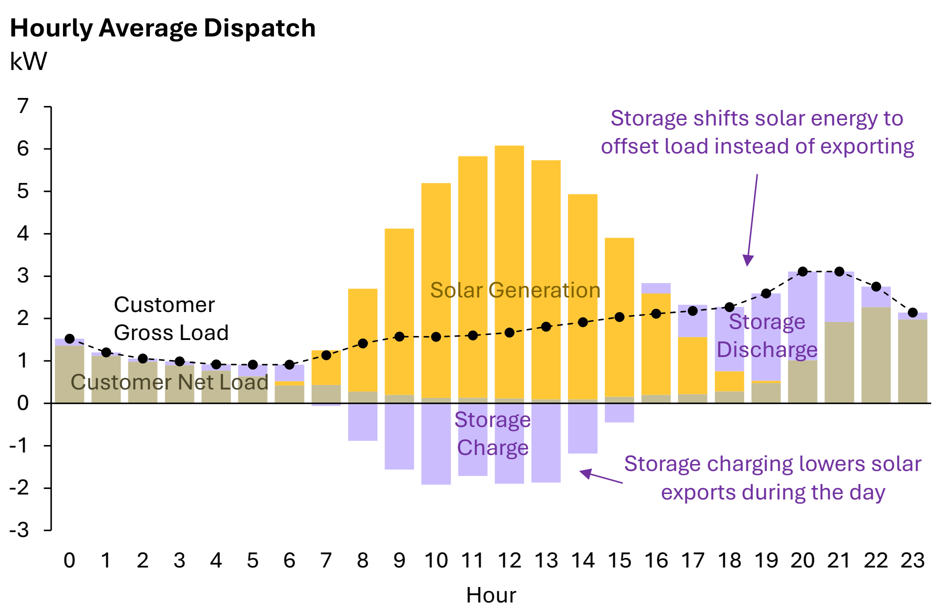
An example of load flattening appears in Figure 19. In the figure, we show an example medium office customer on ComEd's BES Medium Load rate. This rate has a demand charge that is determined by the customer's maximum monthly non-coincident peak usage. So if their highest registered consumption rate during a given month is 300 kW, the demand portion of their bill will show 300 kW × $11.61/kW = $3,483. To reduce this charge, the energy storage behind this customer's meter charges from the grid during the low usage hours of each day (adding net load to hours with headroom) and discharges back to the grid during the high usage hours (reducing net load from those hours). The result is a relatively flat daily energy shape for the customer and an average demand charge reduction of $1,161 per month.

Figure 19. Example load flattening to reduce demand charges



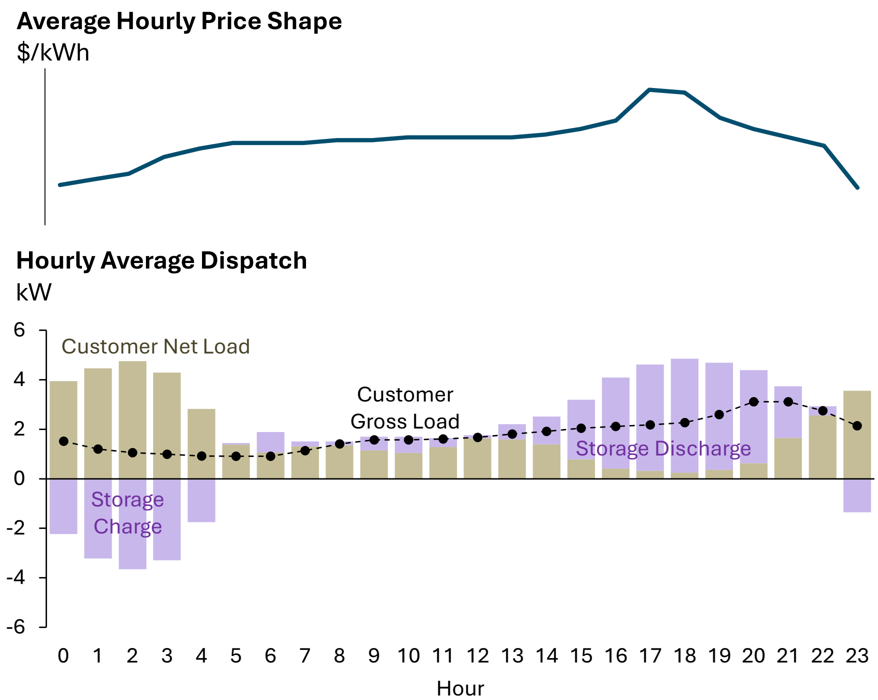
Customers whose rates do not include time variation have no need to avoid high-priced times of day. A customer on a flat rate with standalone storage would have no incentive to charge and discharge. However, customers that have solar paired with storage will want to use their storage to maximize the value of their solar. Recall from Section 2.4.2 that net metering exports are credited at less than the full retail rate. So long as the difference between the full retail rate and the export rate can overcome storage round trip efficiency losses, the customer would follow the example shown in Figure 20. Here the storage charges from solar that would otherwise be exported to the grid, and then discharges during hours in which the gross load can absorb the discharge without exporting any to the grid.

Figure 20. Example use of storage to reduce exported solar



Customers whose rates include time variation through the volumetric energy price have a more natural storage dispatch opportunity. They charge their storage from the grid during hours of the day when the volumetric rate is low, and discharge back to the grid when the volumetric rate is high. An example of this behavior appears in Figure 21. This daily price arbitrage leads to bill savings in every instance that the price differential overcomes roundtrip efficiency losses. In order to ensure that storage deployed behind the meter has a signal to cycle, Illinois requires energy storage owners to enroll in some time-varying rate in order to receive the existing upfront storage rebate. Available time-varying rates range from simple Time-of-Use (TOU) offerings to the Real-Time Pricing (RTP) rates offered by each utility.

Figure 21. Example use of storage dispatch in response to Real-Time Pricing



We create a mapping, shown in Table 11, to assign each use case customer to a rate. On top of this, we impose that any standalone energy storage or solar+storage customer signs up for RTP supply. This assumption aligns with the aforementioned requirement for energy storage owners today who receive an upfront rebate. However, we also evaluate solar+storage customers on the flat supply rates in the table to understand how dispatch may look for hypothetical customers that decline the storage rebate. RTP pricing provides a bookend of the value energy storage can provide to customers and to the grid. Any less granular set of TOU blocks would align less well with grid needs and price extrema.

Table 11. Rate assumptions for use cases

Utility Territory	Customer Type	Rate
Ameren	Single family	DS-1
Ameren	Multifamily	DS-1
Ameren	Medium office	DS-3
Ameren	Primary school	DS-3
ComEd	Single family	BES Single Family
ComEd	Multifamily	BES Multifamily
ComEd	Medium office	BES Medium Load
ComEd	Primary school	BES Medium Load

The modeled RTP rates maintain the delivery portion of a customer bill in line with Table 11 but shifts supply rates to align with marginal energy prices taken directly from our avoided cost of energy (see Section 3.3). We emphasize that the delivery part of the bill remains flat underneath the supply rate variation, which leaves some system cost/value unaligned with rates, even under RTP. ComEd has proposed a time-varying delivery rate in docket 24-0378, but with this docket awaiting an order, we have no certainty on the outcome of the proposal. Ameren also has optional EV rates (EVCP DS-1 and EVCP DS-2) that include some time-varying delivery charges, but these rates are unavailable to non EV–owning customers.

We do not assume any unique rates for LMI customers. Illinois residents whose income is at or below 200% of the federal poverty level are eligible to receive LIHEAP (Low Income Home Energy Assistance Program) bill assistance, and residents whose income is at or below 150% of the federal poverty level can opt instead into a PIPP (Percentage of Income Payment Plan) which limits energy bill spending to 6% of income. Functionally, participation in either of these programs may mute bill savings of DER ownership, but we prefer to omit this effect in favor of representing customers who sit just above these eligibility thresholds, or below the thresholds but do not participate in the programs.

3.6 State and federal incentives

Section 2.4 describes the state incentives available for DERs. These incentives are funded by Illinois ratepayers through adders to their billing rates, which means that they show up as benefits for participating customers, but as costs for nonparticipant ratepayers. Federal incentives provide a more universally beneficial incentive. These programs are funded through federal taxes, and so we can regard the incentives as a benefit to Illinois in the form of dollars flowing into the state.

DER solar and storage are both eligible to receive upfront incentives via the Investment Tax Credit (ITC) of the Inflation Reduction Act (IRA). The ITC Base incentive is a 30% credit calculated as a percentage of upfront capital cost. We assume that all use cases receive this base incentive. On top of that, the IRA includes a series of ITC adders based on meeting certain criteria. We assume that LMI customers are eligible for an additional 10% Low-income Community Bonus credit and another 10% Energy Community Bonus credit.

3.7 Non-monetized benefits

We explored quantifying and valuing a set of non-monetized benefits (i.e., benefits that are not included in the utility revenue requirement) that were identified in CEJA and by stakeholders. The non-monetized benefits evaluated are listed in Table 12. While CEJA offers the possibility that non-monetized benefits may be compensated through the Additive Services mechanism, we do not see convincing evidence that any of the listed benefits in the table should be compensated through Additive Services today. The subsections below detail these benefits, methods for quantification, reasons for exclusion for Additive Services, and possible future developments that could alter our assessment of inclusion.

Table 12. Non-Monetized Benefits

Non-monetized Benefit	Assessment Approach	Included in BCA?	Recommended for Additive Services Compensation?
Reliability	Quantitative	Yes	No (already accrues to host customer)
Resilience	Quantitative	Yes	Not in current version
Environmental Justice	Qualitative	Not in current version	Not in current version
Financial Risk Reduction from Fuel Price Volatility	Quantitative	Yes	Not in current version
Controllable Flexibility to Increase DER Interconnections	Quantitative	No	Not in current version
Methane Leakage	Quantitative	Yes (included in Avoided Energy Cost)	Not in current version
Voltage Regulation/ Optimization	Qualitative	Not in current version	Not in current version
Proximity to MHDV Charging	Qualitative	Not in current version	No (assuming included in distribution avoided cost)

3.7.1 Reliability

Reliability values a DER’s ability to maintain electricity service for a customer during a standard outage. We use a Value of Lost Load (VOLL) methodology to determine the value of a DER’s reliability for a customer. We assume this value is only captured by DERs including energy storage, since a DER would need to be configured to dispatch to provide backup power to the customer in the event of an unexpected outage. Improvements to reliability achieved through customer-owned backup power systems provide a benefit for the host customer in the form of served load that would otherwise go unserved. However, it is our understanding that these improvements do not impact utility spending on reliability. Since there is no wider grid benefit that is currently uncompensated, we do not recommend any incentive compensation for reliability.

The achievability of this benefit is also unclear based on typical DER behavior during an outage. To protect line workers during an outage, DERs are required by the Institute of Electrical and Electronics Engineers (IEEE) 1547-2018 standard to cease energizing the distribution system within two (2) seconds of the loss of the utility source. Most commonly today, this is achieved by DER inverters tripping off when an outage is detected[7], which would also keep the DER from providing energy to a host customer. Though less common, it is also possible for a customer + DERs to physically island from the rest of the grid in order to continue using energy from the DER.

We calculate the annual reliability value as a product of the VOLL, the customer load covered by the battery, and the expected number of outage events per year. To determine the VOLL, we rely on the DOE's Interruption Cost Estimate (ICE) Calculator, which calculates the cost per unserved kWh based on ComEd and Ameren's SAIFI, SAIDI, and CAIDI values. The customer load covered by the battery is determined based on the average outage duration, the battery duration, and a derate equal to the battery's average modeled state of charge. Finally, the average outage frequency comes from the SAIFI value reported by each utility.

For example, for ComEd's territory, the cost per unserved kWh is \$5.94/kWh. The average outage duration in ComEd's territory is 1.1 hours, therefore, a backup system can provide a full reliability value of \$6.63/kW-yr. However, the ability for a battery storage system to provide full reliability benefits depends on the battery's duration and its reserve capacity during an outage. If a battery's duration is 2 hours but the average outage duration is 1.1 hours, then the battery covers 100% of the customer's load during the outage. However, this would not be the case if the average duration outage was greater than 2 hours. Further, a battery may only have 50% in reserve to cover load during an outage since the battery may not be able to charge enough from solar or grid due to weather conditions. In this example of a battery with a 2-hour duration and reserve capacity of 50%, the battery provides \$3.31/kW-yr in reliability value.

3.7.2 Resiliency

Resiliency values a DER's ability to provide electricity during low-frequency, high-consequence outages. We assume that DER solar is configured to provide power to a customer when islanded from the grid and therefore assign some resiliency value to solar, community solar, and solar+storage use cases. We use a "revealed preference" methodology that uses the cost of backup generation and the fraction of customers who pay for backup generation as a proxy for the value of served load during resiliency events. Resiliency benefits accrue to host customers, though they may also spread to surrounding community for commercial or municipally owned DERs. The question of achievability arises for resiliency as it did for reliability – the customer would need to detach from the grid to utilize their DER during an event. Due to uncertainty of achievability, and because some

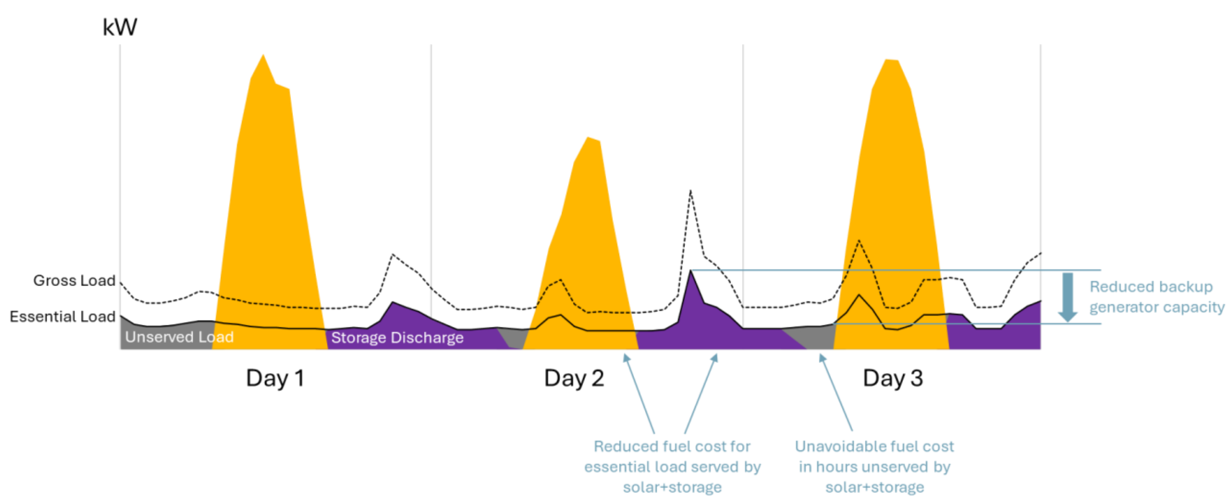
[7] See Ameren's comments in https://icc.illinois.gov/api/web-management/documents/downloads/public/CEJA/Workshop%203%20-%20Stakeholder%20Comments%20Combined%20File.pdf

fraction of the total benefit, if achieved, would accrue to the host customer, we do not recommend compensation for reliability improvement at this time.

We calculate the resiliency value for a 1-week outage every 10 years and we assume that a DER system can *offset* but not replace the generation from a traditional standby backup generator. Our approach assesses the avoided upfront and fuel costs of downsizing a traditional generator. We calculate the avoided upfront cost based on the sales cost of the generator, and we calculate the avoided fuel cost based on the outage days per year and the load served by the DER, instead of the backup generator, over the 25-year DER lifetime.

While this method is similar to the method proposed by the Joint Solar Parties to value resiliency, a few key differences merit mentioning. First, the Joint Solar Parties propose using, as a proxy, the full cost of a backup generator, complete with installation and other auxiliary costs. We note that this is a cost that residents pay for *firm* backup generation that they know will show up when called upon and that this is too high a cost to represent solar or solar+storage, which has limited reliability during resiliency events. Accordingly, we use a proxy that assumes that a DER system offsets, but does not replace, the back-up generation from a propane or natural gas generator needed to cover a customer's essential load during an outage. As illustrated in Figure 22, we determine the avoided upfront cost of a backup generator by sizing down the generator based on the customer's DER system size while still meeting the customer's essential load.

Figure 22. Reduced Backup Generator Capacity with Backup Storage System



A second key difference from the Joint Solar Parties' assumptions is the inclusion of a "customer segment preference" value to derate the proxy reliability value based on the number of customers that value resiliency at or above the cost of a backup generator. We use values of 6%[8] and 75%[9] for

[8] New York Times. "Backup Power: A Growing Need, If You Can Afford It." https://www.nytimes.com/2023/05/06/business/energy-environment/backup-power-generators-climate-change.html

[9] National Energy Technology Laboratory. "The Untapped Value of Backup Generation." https://netl.doe.gov/sites/default/files/Smartgrid/Value-of-Standby-Generation-08-29-08-AZ--2-_APPROVED_2008_09.pdf

residential and commercial customer segments respectively. We acknowledge that this is a somewhat conservative approach as it assumes that the remaining customers do not value resiliency, however we prefer to reflect the percent of customers who have revealed a preference for the certainty of a standby backup generator rather than assuming all customers value resiliency at the cost of a backup generator.

3.7.3 Environmental Justice

Environmental justice (EJ) recognizes the added value of DER benefits that accrue to EJ communities, possibly by siting DERs in an EJ community or by facilitating DER participation by EJ community members. Valuing EJ as a non-monetized benefit accounts for the benefits of DERs to communities that historically have had less access to DERs. We recommend that Environmental Justice considerations be included in the Base Rebate and/or Additive Services incentive structure but note that clearer policy goals are needed to guide this inclusion before it can be realized.

Inclusion of EJ considerations could take many forms: increased incentives to EJ community members, decreased/eliminated payments into the incentives by EJ community members, incentives to spur DER development in EJ areas, etc. Ultimately, we suggest that the goals of any EJ-targeted incentive be made explicit before creating an incentive. If the primary goal is to give EJ community members access to DERs because DERs provide bill savings, then focusing on more direct bill savings mechanisms may be preferable: for example, expansion of bill discount programs that do not share program funding dollar with developers or insist on participants engaging with a new technology to receive benefits. Alternatively, goals like decreasing energy infrastructure builds in EJ communities could be well-served by targeted Additive Services incentives if the data to create an effective incentive for that goal becomes available.

Inclusion of an EJ benefit and how that benefit is valued is a policy decision more than an analytical one. We can look to other jurisdictions for examples of how other policy-makers are approaching the topic. In New York, the VDER stack includes a $100-$200/kW “Community Adder” for projects serving LMI subscribers, affordable housing, residents of disadvantaged communities, plus select nonprofit and public facilities providing guaranteed discount of 10%. Meanwhile, the Solar Massachusetts Renewable Target (SMART) program includes various adders for providing generation to low-income properties, proactively engaging local community, and enrolling at least 40% LMI customers in community solar projects. We caution the use of incentives to spur LMI adoption in the context of possible cost shifts between participants and non-participants: facilitating LMI adoption of DERs does not avoid creating a cost-shift between LMI participants and LMI non-participants.

The value of this benefit is ultimately a policy decision, and the benefit is qualitative in nature, dependent on the location of the DER or who is receiving the value from the DER. A DER’s compensation level for providing EJ benefits will depend on how much capacity policymakers want to incentivize for development in EJ communities and how much incentive is needed for that development.

3.7.4 Financial Risk Reduction from Fuel Price Volatility

Financial risk reduction values the benefits DERs can provide to reduce exposure to wholesale electricity price volatility driven by volatile natural gas and biofuel prices. To be clear, the value of this benefit is in the reduction of exposure to risk, similar to what would be achieved by forward gas purchases to hedge risk. The value of this risk reduction is distinct from making any assumption about whether future gas prices will be lower or higher than forecast. This fuel price risk is only applicable during years and hours during which natural gas and biofuels are the marginal generator. As Illinois reduces its reliance on natural gas generation over time, the financial risk reduction that results from fuel price volatility is also reduced over time.

Our understanding is that ComEd and Ameren do not hedge their electricity purchases to reduce exposure to fuel price volatility. We note that IPA, in managing procurements for Ameren and ComEd, does hedge short-term supply price risks for customers to mitigate uncertainties such as load forecasting, weather impacts, and customer migration to alternative suppliers. However, it is unclear to what extent these strategies mitigate or aim to mitigate volatility in fuel costs.

According to the IPA's most recent procurement plan, its historical strategy involves a "laddered" approach: purchasing a significant share of forward contracts over a three-year horizon to serve retail customers.[10] While these forward purchases protect against near-term price fluctuations, they can end up being higher or lower than spot prices. Therefore, customers do not necessarily pay a premium specifically for hedging fuel price risk.

The benefit of reducing long-term hedging considers a different angle by considering the value of having dollars available instead of tied up in a long-term futures contract. If futures purchases are reduced be DER offsetting forecast gas generation, an entity has more funds available for investment with a higher return. Neither utilities nor IPA purchase long-term gas futures to hedge against price volatility, so this benefit has no real monetary value. Still, we can use this construct to discuss the long-term fuel price exposure risk that is passed through to ratepayers via an unhedged supply cost.

Given the possibility of upside or downside impacts and the lack of clear evidence of the premium utilities or IPA pay to hedge fuel price volatility, we do not recommend that short-term fuel price risk reduction be compensated through the Additive Services incentive. We do not recommend that long-term fuel price risk reduction be compensated either because utilities and the state do not engage in long-term hedging. Still, we quantify the hypothetical value of avoiding a long-term hedge in order to deepen the discussion of this possible value for future consideration.

The reduced financial risk is quantified by estimating how much a utility would spend on a hypothetical hedging strategy, and the extent to which this hedging cost could be offset by the presence of added generation that is not fuel-based. This aligns in principle with the approach

[10] https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/ipa-2025-electricity-procurement-plan-for-icc-approval.pdf. Page 67.

suggested by the Joint Solar Parties, who point towards a Distributed Solar Valuation study performed for the Maine Public Utilities Company by Clean Power Research.[11]

We first determine the set of hours in which gas- or biofuel-based generation is projected to be on the margin for each modeled year. We calculate hourly implied heat rates for wholesale electricity by dividing the $/MWh hourly energy price forecast by the $/MMBtu natural gas price forecast. In the calculations, the implied heat rate is bound using a minimum of 7 MMBtu/MWh and a maximum of 12.5 MMBtu/MWh to represent the range of heat rates for natural gas and biofuel generators.

To value the cost of hedging, we assign a hypothetical hedging price of $1/MMBtu to these hours – any fuel use avoided during these hours also corresponds to avoidance of the hedging price. This hedging price is based on an analysis by RMI that cites case studies on how much utilities pay to hedge variability in fuel prices.[12] This hedging value is multiplied by the hourly implied heat rate to find the $/MWh cost of hedging for each hour. Avoidance of this cost provides a proxy for the value to ratepayers of fuel price volatility risk reduction.

We note that the elected value of $1/MMBtu has been debated by some parties. We welcome continued debate on this topic, but offer a few key considerations to frame this debate:

- Derivation of a new risk adder should use the same gas price forecast used otherwise in the study.
- Derivation of a new risk adder must acknowledge the hours of each year in which gas or biofuel will and will not be the marginal resource. Distributed generation only provides value when displacing marginal gas generation, while storage resources only provide value if they are charging from a non-gas resource and discharging to displace a gas resource.
- If only included as an element in the TRC+ screening test, as proposed here, the fuel price risk reduction value itself tends to be inconsequential to compensation: the risk reduction benefit may help a resource pass the proposed TRC+ screening test but does not change the RIM test result.

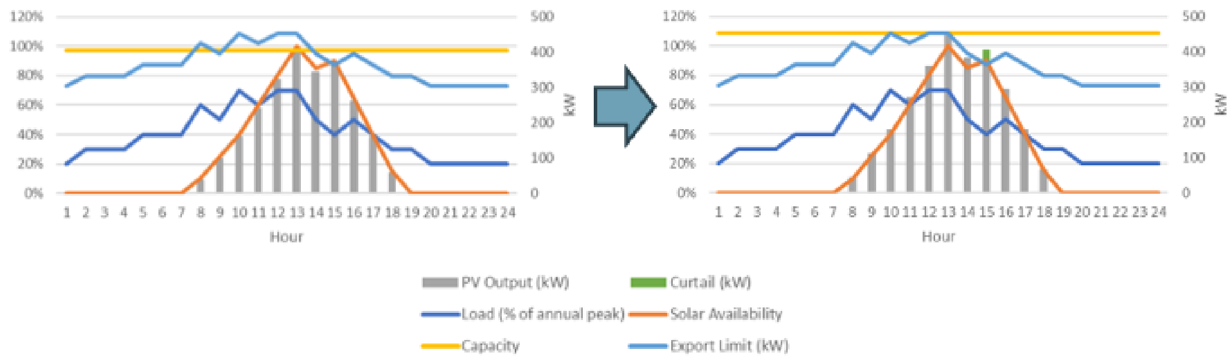
3.7.5 Controllable Flexibility to Increase DER Interconnections

Controllable flexibility values the ability to interconnect additional DERs under existing interconnection limitations while controlling DERs for flexible output. Dynamically controlling DER exports can avoid overgeneration during hours with interconnection limitations. For example, overgeneration of rooftop solar is only a concern in the hours with interconnection constraints, which may only be during a few hours or days on the system. However, if the solar exports to the grid can be curtailed for the rooftop solar or several rooftop solar arrays during those constrained hours, then there is an opportunity to connect more DERs or install a rooftop solar system with greater capacity as illustrated in Figure 23. This additional solar capacity can generate and export to the grid

[11] https://energynews.us/wp-content/uploads/2018/07/26.-C-MPUC_Value_of_Solar_Report_final-11216.pdf
[12] RMI. Utility-Scale Wind and Natural Gas Volatility. https://rmi.org/wp-content/uploads/2017/05/RMI_Document_Repository_Public-Reprts_2012-07_WindNaturalGasVolatility.pdf

during the rest of the year without exceeding the interconnection constraints, providing greater overall system value.

Figure 23. Solar Capacity Increase Enabled by Flexible DER Control[13]



We recommend that controllable flexibility be quantified and compensated when the value can be fully realized. However, determination of the correct value for compensation is nontrivial. Value provided by extra DERs fit into the same headroom will be paid out to those extra DERs through their own incentives, so the value provided by the "first-in" DERs is most-likely the value of accelerated interconnection of those new DERs. A DER that is able to interconnect without waiting for infrastructure upgrades can provide benefits to the system sooner, and this value could be quantified by looking at the difference in Net Present Value (NPV) benefits provided by the same DER given different install years. Implementation challenges will also need to be overcome for this benefit to be realized: there will need to be agreements with DER owners and additional utility controls on the DER systems to ensure that DER generation does not exceed the system constraints.

3.7.6 Methane Leakage

Methane leakage values the avoided GHG cost of methane leakage from the production and transmission of gas to natural gas electricity generators. The benefits of avoiding methane leakage are captured in the avoided energy cost, which includes the embedded GHG value. More specifically, the embedded GHG costs include precombustion emissions, such as fuel extraction, processing, transport, and fugitive emissions. The fugitive emissions are calculated by NREL assuming a 2.3% national average leakage rate.[14] As methane leakage is already included in the avoided energy costs, methane leakage should not be separately quantified in the BCA model. Because this benefit relies on reducing gas generation, we point to the same reasons listed in Section 3.7.4 to argue that it should not be compensated today.

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[13] Figure credit: ComEd
[14] Assessment of methane emissions from the U.S. oil and gas supply chain

3.7.7 Voltage Regulation and Optimization

Voltage regulation and optimization values a DER's ability to provide voltage regulation and optimization services. The impact of DERs on voltage regulation is uncertain and depends on the inverter design, the level of utility control over the DER, and the DER's position within a given circuit. Each of these uncertainties can be overcome, but the current state of DER utilization by utilities does not guarantee that DERs provide these benefits, much less an ability to value them. The localized nature of the value rules out compensation through the Base Rebate, and we do not recommend compensation for this benefit through Additive Services today. However, the benefit, if realized, saves money for ratepayers and could therefore be included within future Additive Services compensation with no negative impact to ratepayers. We also caution that the voltage-related value of DERs may never materialize since Ameren and ComEd have existing voltage optimization programs targeting this same value with other system hardware.

3.7.8 DER Proximity to Medium- and Heavy-duty Vehicle Charging

DER proximity to medium- and heady-duty vehicle (MHDV) charging values the benefit of siting a DER near medium- and heavy-duty vehicle charging stations. The concept behind this benefit is that DERs located near charging hubs may be able to defer or avoid the need for infrastructure upgrades resulting from charging demand. While plausible, most research to date has focused on pairing light-duty vehicle charging with home solar and storage systems, and there is no substantial research on the benefits of siting DERs near MHDV charging. More importantly, this benefit is highly localized and to quantify the value of this benefit would require more insight into where MHDV charging will be sited in the future. Without better planning/forecasting of the potential locations and investments associated with this charging infrastructure, a value cannot be assigned to the benefit. Accordingly, we do not recommend that DER proximity to MHDV charging be compensated today. In the future, we leave open the possibility of compensation for this benefit, but recognize that the value may already be compensated through a more spatially differentiated distribution avoided cost.

4 Baseline cost-effectiveness results

Based on the benefits described in Section 3, we take a moment to explore the current cost-effectiveness of our previously identified DER use cases. Compiling these results provides necessary context for the compensation formula that follows. The cost-effectiveness tests tell us the extent to which, prior to additional incentivization, DER adoption is promoted by customer economics, is providing net benefit to the grid, and is not contributing to affordability concerns for ratepayers. As described in Section 2.3, these metrics are captured by the PCT, the TRC+, and the RIM test. We show in Table 13 the specific benefits and costs that feed into each of these tests.

Table 13. Benefits and costs for each cost test

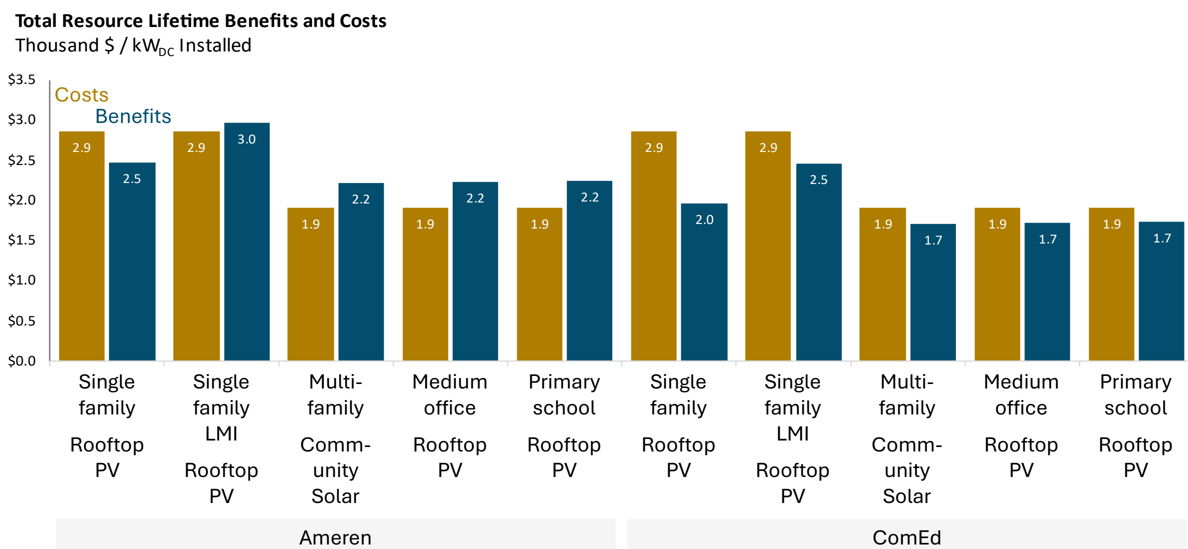
Category	PCT	RIM	TRC+
Capital Cost	Cost		Cost
Interconnection Cost	Cost		Cost
O&M	Cost		Cost
Federal Incentives	Benefit		Benefit
Net Metering Payments	Benefit	Cost	
ABP (Illinois Shines / Solar for All Incentive)	Benefit	Cost	
Base Rebate	Benefit	Cost	
Additive Services Incentive	Benefit	Cost	
Other Bill savings	Benefit	Cost	
Reliability and Resiliency	Benefit		Benefit
Environmental Justice			Undetermined
Financial Risk Reduction			Potential Benefit
Controllable Flexibility			Potential Benefit
Methane Leakage			Benefit
Voltage Regulation and Optimization			Undetermined
DER Proximity to Vehicle Charging			Potential Benefit
Avoided Energy		Benefit	Benefit
Avoided Generation Capacity		Benefit	Benefit
Avoided Monetized GHGs		Benefit	Benefit
Avoided Transmission		Benefit	Benefit
Avoided Distribution		Benefit	Benefit
Losses		Benefit	Benefit

All results in this section assume a specific DER has an install year of 2025 and a 25-year assumed life. Results presented on an NPV basis use a nominal discount rate of 6.32%, based on a simple average of Ameren and ComEd's after-tax weighted average costs of capital. Annual inflation is assumed to be 2.00% each year. The supply portion of utility rates (non-real time pricing) are modeled to escalate either at 1% nominally to align with avoided energy cost escalation, and the delivery and other components of utility rates are modeled to escalate at 2.5% nominally. Where real time pricing is applied, the supply portion of the bill is aligned to the energy avoided costs, adjusted upward to account for losses. Initial rate inputs for each customer class come from the utilities' 2024 tariffs. Additional assumptions and sources beyond those previously addressed are described in Appendix E.

4.1 Rooftop and Community Solar

Figure 24 provides a high-level summary of the TRC+ cost test results for the ten solar use cases. Within each pair of bars, the left-hand bar shows costs while the right-hand bar shows benefits. We see mixed results, with benefits exceeding costs for most Ameren use cases, but costs exceeding benefits for all ComEd use cases. Where costs exceed benefits, this indicates that DER solar is not a better economic solution than bulk resources for meeting the state's energy needs. In the Ameren cases, with lower costs and the LMI use case, the net benefits indicate that the state, as a whole, would benefit from DER solar deployment.

Figure 24. TRC+ results for rooftop and community solar use cases



Appendix E provides results broken down by component for each use case. The closer look at individual cost and benefit components in the appendix reveals the drivers behind the variation from case to case. Costs are consistent across rooftop residential cases but shrink for non-residential and community solar installations which benefit from economies of scale. Because the ITC is provided on a percent-of-capital cost basis, the per-unit ITC benefits are also smaller for these installations. LMI use cases are assumed to have access to an additional 20% ITC bonus, which brings an extra 0.5 $/W$_{DC}$ into the state. Benefits in the form of avoided costs are similar across cases for a single utility, but projects sited in Ameren territory see higher avoided costs due to the higher avoided costs associated with MISO compared to PJM. Community solar avoided cost benefits may be lower than those of on-site solar depending on the location of the solar facility interconnection in relation to the end consumer, though this difference is not modeled as it is assumed to be relatively small and will vary on a case-by-case basis.

Figure 25 presents another high-level view, this time exploring the RIM test. For the RIM, all use cases show net costs, many by large margins. Recall that the RIM costs are bill savings and incentives funded by ratepayers while the RIM benefits are avoided costs. Thus, the results indicate rising rates and a consistent transfer of dollars from non-participants (ratepayers) to participants (DER owners) as a result of DER solar uptake. As an example, the first pair of bars indicates that every Watt$_{DC}$ of rooftop solar installed at market rate residential sites in Ameren territory creates a transfer of $2.40 from ratepayers to the rooftop PV owners. This result is primarily driven by the high electric rates relative to avoided costs and generous ratepayer-funded solar incentive programs. The Ameren Commercial use case provides a valuable counterfactual: smaller ABP incentive values for larger systems and a rate design that collects revenues with demand charges in addition to volumetric ones temper participant incentives (and therefore nonparticipant costs) to better align with the monetized value provided to the system. These RIM results should give pause at the prospect of increasing costs with more ratepayer-funded incentives.

Figure 25. RIM results for rooftop and community solar use cases

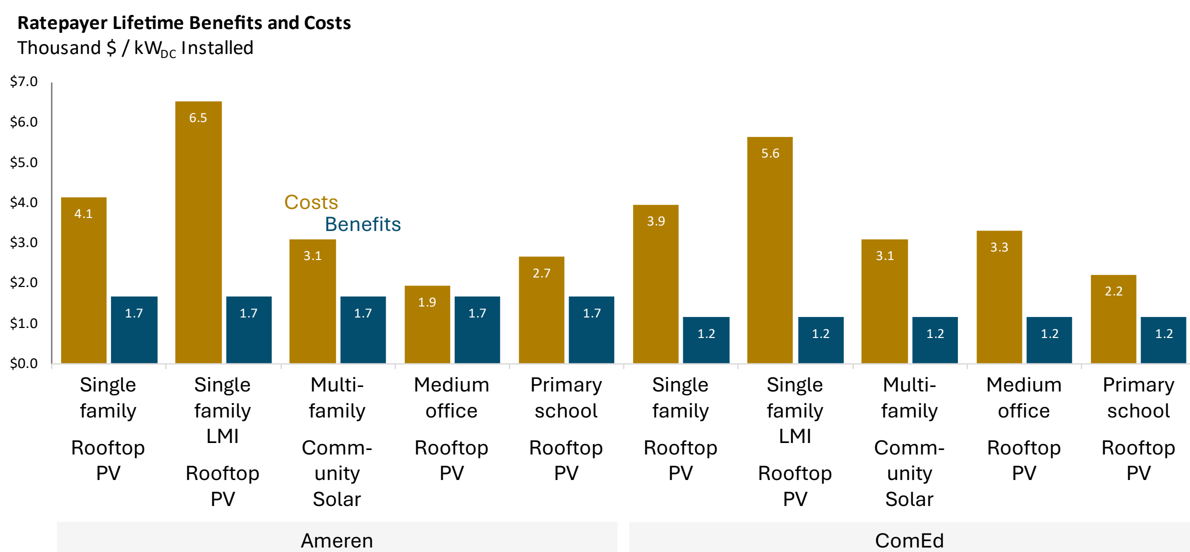
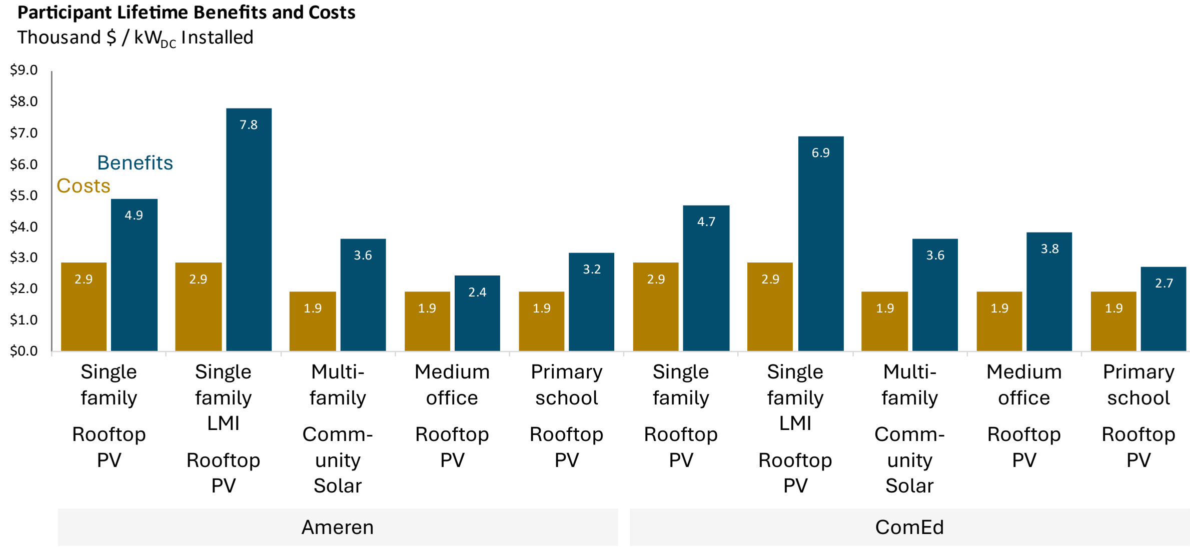


Figure 26 shows the participant cost test results for the same set of use cases. Across the board, the PCT shows net benefits, indicating that participants will save money by installing the DER. In other words, Illinois residents already have a strong signal to install PV without any increase to the Base Rebate above the floor value or any Additive Services compensation. This result is driven by the same elements that create high costs for ratepayers: large bill savings and generous incentives through NEM, the Base Rebate, and the Adjustable Block Program. We note that these results are consistent with ComEd's analysis of single-year solar PV costs and bill savings for single family installations.[15]

[15] https://icc.illinois.gov/api/web-management/documents/downloads/public/informal-processes/equitable-energy-upgrade-plan/ComEd%20-%20Low%20Income%20Solar%20via%20EEUP%20-%20ICC%20Workshop.pdf

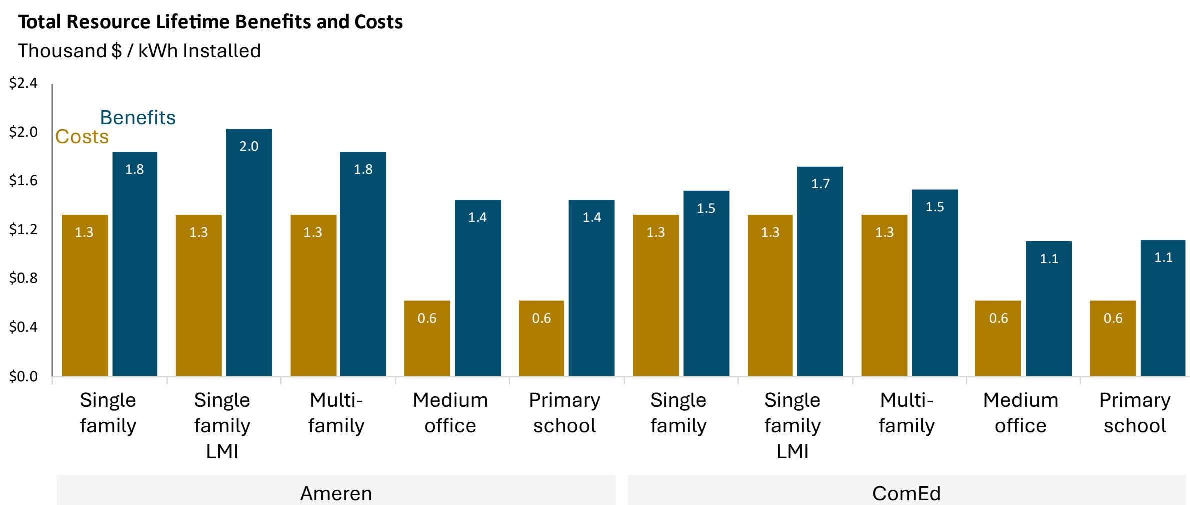
Figure 26. PCT results for rooftop and community solar use cases



4.2 Standalone energy storage

We turn to the same set of example customers, but now examine standalone storage use cases. Figure 27 provides the TRC+ results for this set of use cases, and we note the apparent difference between this figure and the corresponding result for DER solar use cases: standalone storage use cases show net benefits for the state. These systems, dispatched based on RTP signals, provide value to the grid that exceeds their net cost.

Figure 27. TRC+ results for standalone energy storage use cases



The more detailed breakdown of TRC+ benefits in Appendix E reveals the source of the value to the grid. Avoided energy and avoided generation capacity are the main sources of benefit. We note that these values could also be captured by grid-scale energy storage which would have a lower upfront cost than distributed storage. Value to the distribution system is small – on the order of $60 to $80/kWh of storage capacity – but worth noting, since this is the primary value targeted for compensation by this study.

Figure 28 provides RIM test results for this set of use cases, and again the story differs from the DER solar example. As noted in the TRC+ graphics, the value to the system and therefore to ratepayers is significant. Meanwhile, because standalone storage is a net load – not a generator – and because there is no upfront ratepayer-funded incentive for energy storage (i.e. the Base Rebate floor is zero) costs are small. The result is a net benefit to ratepayers due to efficiently dispatched storage.

It is worth noting the disconnect here between flat delivery rates and avoided cost values with hourly shape. For example, the distribution avoided cost is zero in many hours, but the storage tends to be dispatching when this avoided cost is non-zero. However, the distribution component of the rate (part of the delivery charge) is flat, which means that the act of charging and discharging on this flat rate costs the battery money in proportion to its efficiency losses. However, the money gained through arbitrage of the supply rate overcomes this cost. Absent the RTP supply signal, there would be no dispatch against this flat rate and no value provided to the grid.

Figure 28. RIM results for standalone energy storage use cases

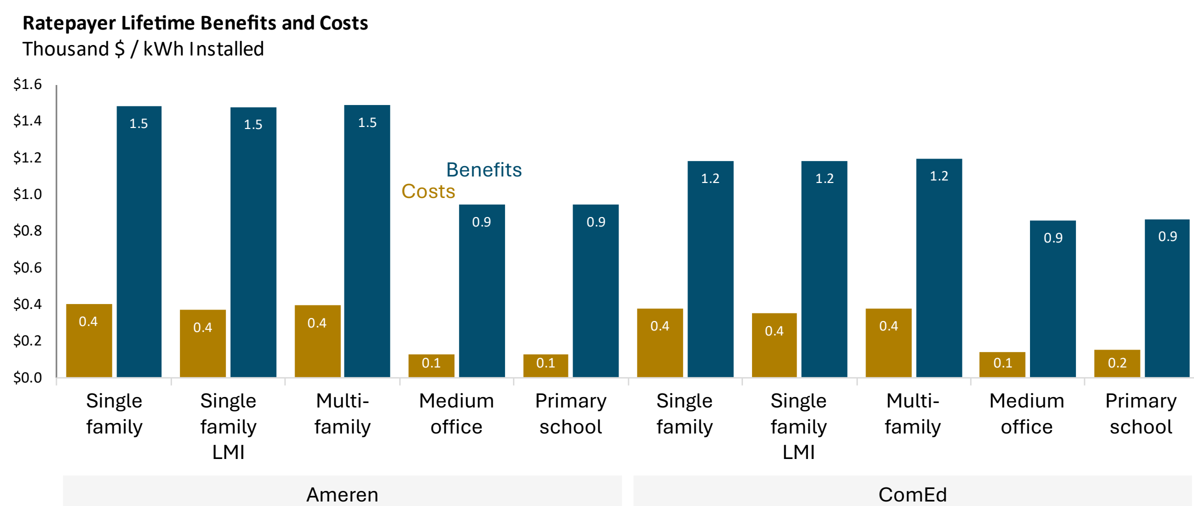
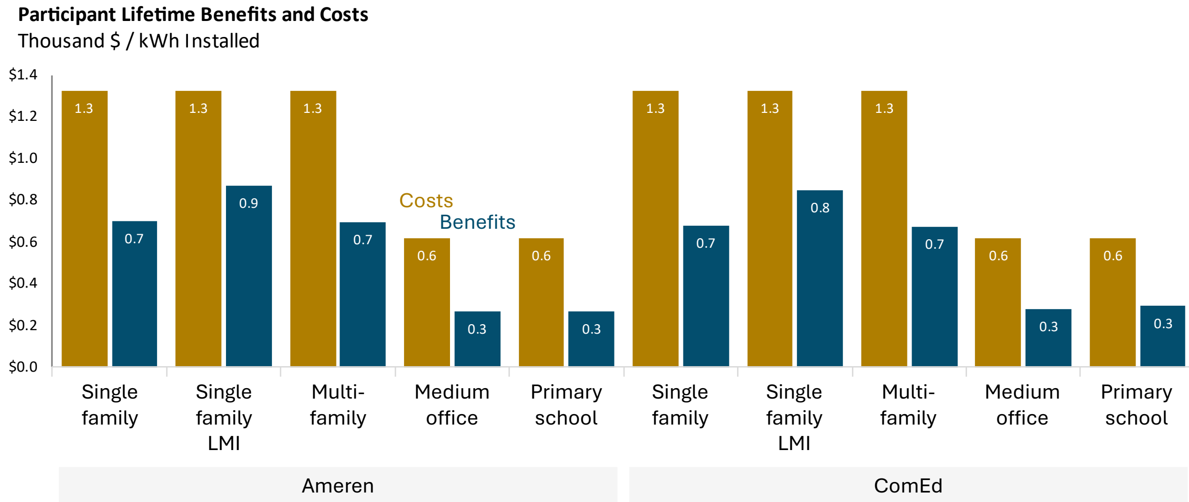


Figure 29 provides the PCT for the standalone storage use cases. Given the lack of incentives provided to energy storage and the only partial opportunities for bill savings, we are not surprised to see net costs. Based on this result, residents and developers do not have much incentive to install DER storage in the state, even at commercial sites where they can take advantage of economies of scale for lower capital cost.

Figure 29. PCT results for standalone energy storage use cases



4.3 Solar+Storage

Solar+storage use cases tell a similar story to solar-only use cases. Figure 30 shows the TRC+ results normalized by the solar capacity to make comparison to Figure 24 simpler. Costs and benefits both grow compared to the solar-only case, but the growth in costs tends to outpace the growth in benefits. The figure also shows dashed outlines on top of each solid bar. These outlines show the costs and benefits of a case in which the host customer has not enrolled in a time-varying rate. As expected, the lack of a grid-needs-aligned dispatch signal decreases benefits universally. We remind the reader that we do not consider a multifamily solar+storage use case due to the inability to co-locate behind the meter storage with community solar.

Figure 30. TRC+ results for solar+storage use cases

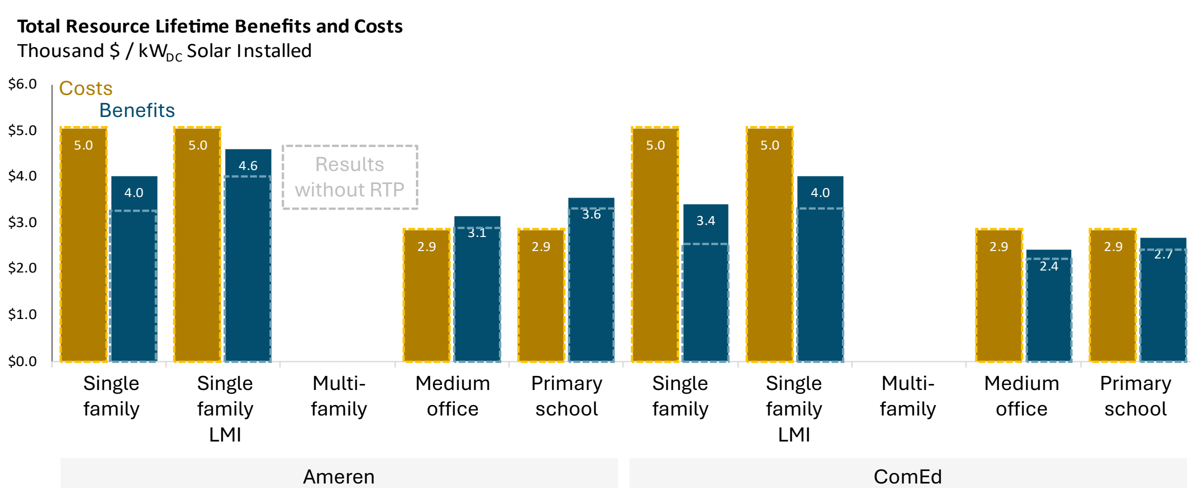


Figure 31 shows that the RIM test also mirrors the solar-only results. Interestingly, potential increases in costs due to storage allowing for more onsite consumption of solar generation are offset by RTP participation, which tends to lower the value of the unshifted solar generation. In some commercial rate cases, benefits and cost break even, indicating that the solar+storage is putting zero or perhaps even downward pressure on non-participant bills.

Figure 31. RIM results for standalone solar+storage use cases

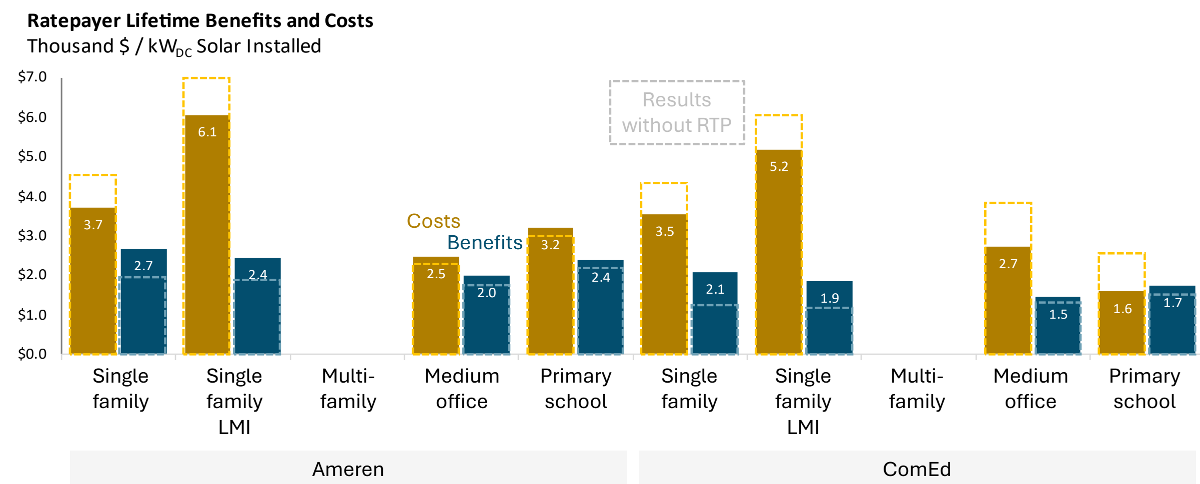
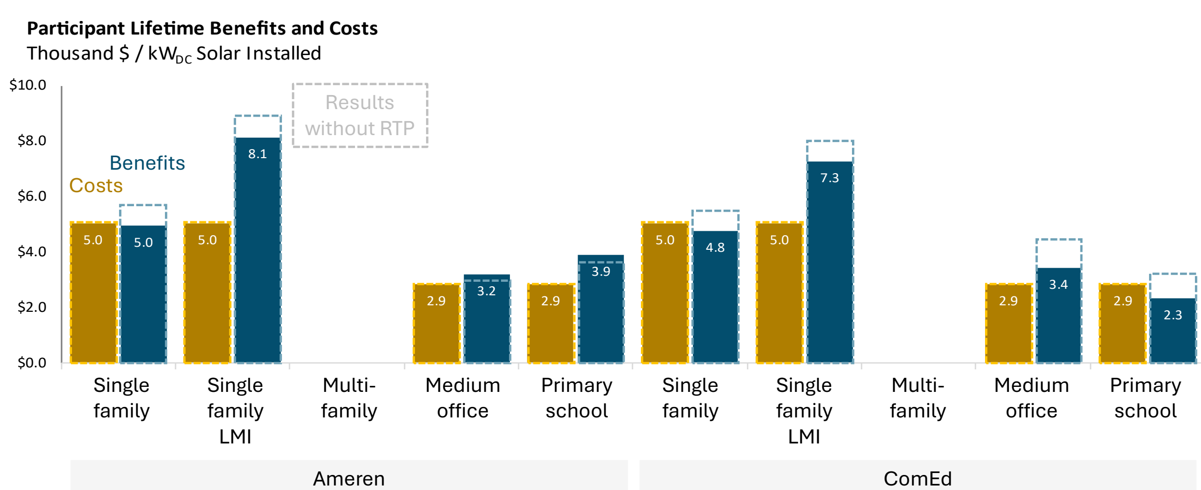


Figure 32 shows the PCT results for solar+storage use cases. In many cases, the bill savings and incentives provided to solar provide enough margin that the less cost-effective storage can be added while maintaining net benefits. However, we see in some cases that the switch to RTP flips a use case from showing net benefits to showing net costs. Given the option, some customers might choose to forego a storage incentive in order to keep more of their solar production credited at the flat rate. This provides a less cost-aligned storage dispatch signal and is an unfavorable outcome.

Figure 32. PCT results for standalone solar+storage use cases



5 Proposed Compensation Formula

Using the results of the previous section, this section formalizes the approach to incentivization described in Section 2 to create a concrete proposal for how Base Rebate and Additive Services DER compensation should be determined. This section can serve as a guide for the drafting of the proposed rule language that will accompany the opening of a proceeding on this topic.

We include two possible proposals. The first, our preferred option, prioritizes ratepayer protection by using TRC+ and RIM cost-effectiveness screening and ensures realization of benefits through a time-dependent additive services incentive for energy storage. The latter foregoes any screening to use a component-driven approach to incentivization and a simple upfront payment for dispatchable resources. Both design features of the latter approach increase the risk of ratepayer impacts. Despite these differences, today's results show little variation in recommended compensation values between the approaches – this is largely due to the important and therefore consistent consideration of "net distribution value," which is explained below.

A third option, not listed explicitly below, would be to forego the cost-effectiveness screening but keep incentives for dispatchable resources paid out through the Additive Services incentive. This option would still put ratepayers at risk of cost shifting due to overpayment to DERs, but would better set the state along the path of a performance-based time-varying Additive Services incentive.

5.1 Recommended approach: prioritizing ratepayer protection

This compensation framework provides additional incentives to DERs only if they pass certain TRC+ and RIM thresholds. Additionally, all incentives for dispatchable DERs are reflected in the additive services rather than in a base rebate to ensure that these DERs are rewarded to providing real and timely benefits to the grid.

5.1.1 Rules/calculations defining the mechanism

Base Rebate

The base rebate calculation for a DER is structured as the following:

For a given DER, if TRC+ net benefit is above $X AND RIM net benefit is above $Y, then Base Rebate is the maximum of the **Base Rebate Floor** and the **Net Distribution Value**. Otherwise, Base Rebate is set to the Base Rebate Floor. Main calculation steps include:

- **Net Distribution Value** is calculated as Avoided Cost not Covered by Existing Incentives minus NEM distribution compensation.
    - As described in Section 2.1, the only avoided cost component (i.e., system-wide value of DERs) not covered by existing incentives is the distribution avoided costs. Therefore the Avoided Cost not Covered by Existing Incentives is primarily the distribution avoided cost.

  - Distribution avoided costs should be further reduced for some DERs that are receiving distribution delivery credits. For example, for rooftop solar, NEM currently provides distribution delivery credits to the amount of solar generation used to offset customer load. In this case the NEM distribution compensation should be subtracted from the DER distribution avoided costs in order to calculate Net Distribution Value.
- Net Distribution Value should be capped at the RIM Net Benefit, which is the net present value of RIM cost minus RIM benefit for a given DER.

Figure 33 and Figure 34 provide a visual illustration of this formula. Figure 33 illustrates a scenario in which the state wants to protect ratepayers and sets the threshold for RIM, namely Y, to zero. This scenario implies that the base rebate of a given DER could be higher than the base rebate floor only if the DER provide net benefits to ratepayers.

Figure 34 illustrates a scenario in which the state wants to prioritize DER adoption over ratepayer impact and sets the threshold for RIM to be negative. This indicates that the state allows allocating certain ratepayer funds for DER incentives. Under this scenario, the net distribution value should be capped at the acceptable RIM net costs that are consistent to the threshold Y in order to avoid unintentional rate increase as the result of DER adoption.

Figure 33. Proposed base rebate compensation formula for distributed generation

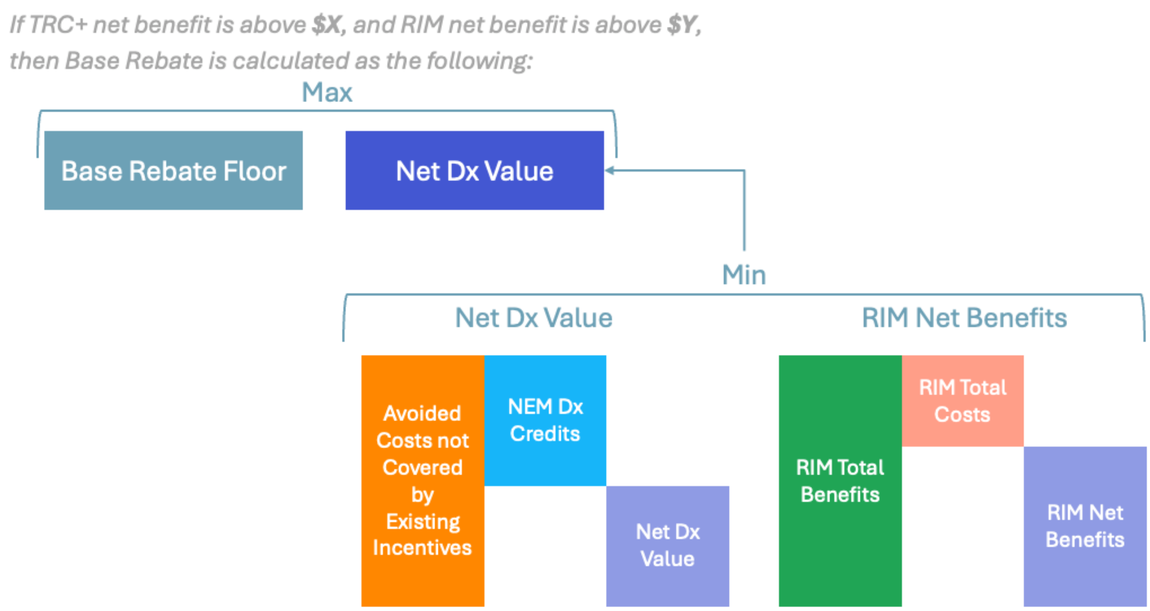
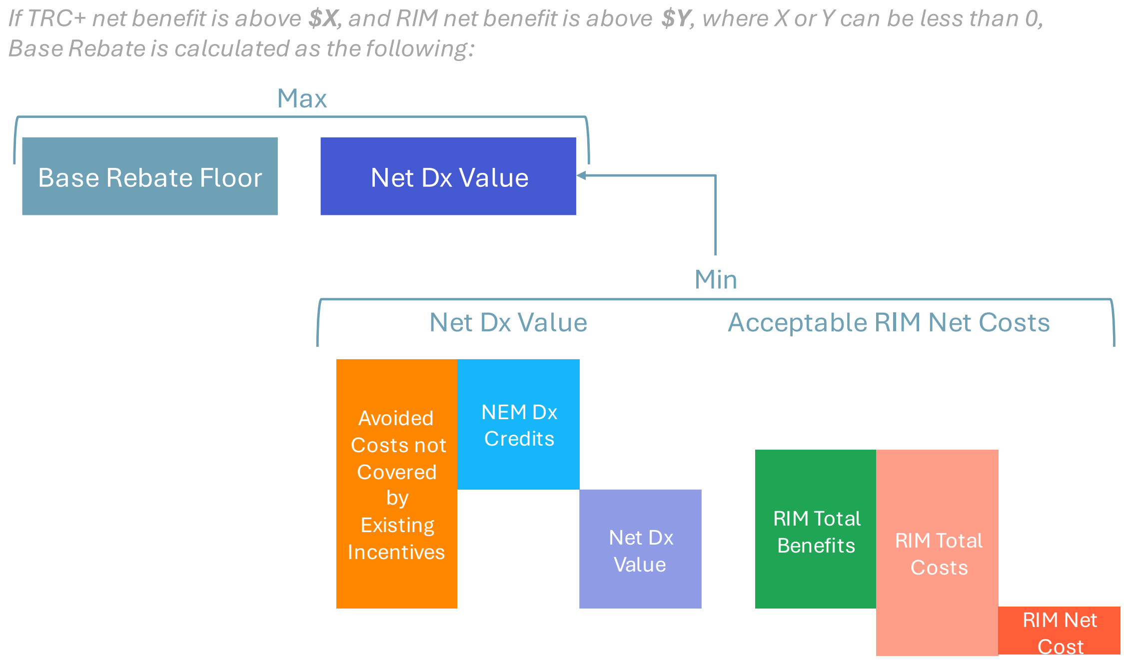


Figure 34. Compensation formula with negative RIM net benefit as threshold



Several guiding design principles and underlying objectives inform the structure and function of the formula, described as the following:

+ If the state wants to award a DER a base rebate above its floor, it should assess DER impact on the society and ratepayers through the TRC+ and RIM cost tests. The threshold X and Y indicate the state's position in balancing various objectives in designing the DER compensation.
+ Base rebate should be greater than or equal to the base rebate floor.
+ The calculation of the Net Distribution Value ensures that the base rebate covers the uncompensated system-wide values of DER. The only system-wide DER value that might not be fully covered by existing incentives is the distribution avoided cost. For some DERs such as rooftop solar, NEM does provide distribution delivery credits, and NEM customers are able to avoid paying delivery charges for energy they generate to offset their electric usage. Because participating customers already see these savings directly, these should be subtracted from distribution avoided costs when determining what remains to be compensated.
+ The Net Distribution Value is capped at the RIM net benefit. This step places protection on ratepayers to ensures that the new incentive does not lead to adversary ratepayer impact.
+ Several components in this formula can be updated in the future as more data become available or as the state changes its prioritization of DER deployment goals (adoption, value realization, ratepayer protection). This framework is designed to provide flexibility for future updates.

We also recommend that incentives for dispatchable DERs be reflected in the additive services rather than in a base rebate, as described in the next section.

Additive Services

As described in Section 3.7, we recommend zero additive service for distributed generation given current research on non-monetized benefits. Some benefits such as reliability and resiliency benefits are already accrued to host customers. Other benefits, including environmental justice, voltage regulation/optimization, proximity to MHDV charge, do not currently have a clear pathway for quantification.

We recommend that incentives for dispatchable DERs be reflected in the additive services rather than in a base rebate. Because dispatchable DERs only create value when they respond to real-time grid conditions—such as shifting load away from peak hours—it makes sense to tie their compensation directly to actual performance. By contrast, a one-time, upfront rebate does not ensure that DERs will be operated in ways that benefit the grid or ratepayers. For example, the timing and extent of storage dispatch depend heavily on price signals as well as on the dispatch decisions made by the storage operator. If the owner simply receives an upfront rebate, there is no ongoing incentive to operate the storage optimally for grid support. In contrast, by linking compensation to actual performance – such as discharge during peak hours – additive service payments guarantee that the DER is rewarded only when it delivers real benefits to the grid, aligning incentives with desired outcomes.

The most direct approach for dispatch-based Additive Services compensation is to adopt a demand response (DR) style incentive. Stakeholders have rightly pointed to the ConnectedSolutions programs of multiple New England states as a good example of a DR program that allows DER participation.[16]

Looking at the Massachusetts ConnectedSolutions program in particular, enrolled energy storage devices allow the utility to use stored energy during times of high demand. Dispatch calls last up to 3 hours and are limited to 30-60 events per year. They only occur between 3 pm and 8 pm during summer months, and never during inclement weather, to avoid competing with using energy storage for home reliability.

Avoided costs for Illinois and their PCAF distribution suggest that around 95% percent of the distribution value is contained within about 15-30 days each year and is spread over roughly 100 hours across these days. Today, these hours fall during summer months, but future years see some of these hours shifting into the winter. More precise guidelines for dispatch calls will come alongside improved distribution cost data, but this preliminary look suggests that criteria similar to those used in Massachusetts could function well in Illinois. However, it is worth noting that many days contain more than three hours of distribution system need. Additional exploration by the utilities would help to determine the best call length criteria, but we note that energy storage with 2- to 4-hour durations may not be able to capture all the program value if longer call periods are deemed necessary.

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[16] https://icc.illinois.gov/downloads/public/edocket/598132.PDF

We caution that the example $275/kW-yr incentive value of ConnectedSolutions in Massachusetts is too high to apply in Illinois. The ConnectedSolutions incentive is meant to reflect the contribution of DR to system peak reductions as opposed to local distribution peak reductions. These system-wide value streams are larger than the average distribution value, and so a larger incentive is appropriate in Massachusetts than for Additive Services in Illinois. We suggest a more modest value below.

5.1.2 Resulting DER compensation

To calculate an initial set of DER compensation values, we set both the TRC threshold (X) and RIM threshold (Y) to zero. This implies that DERs can receive additional incentives only if they provide positive net benefits to the state and ratepayers. Following the formula, we performed the benefit-cost analysis and calculated the Net Distribution Value and RIM Net Benefit for our representative use cases. We do not separate out LMI use cases in these results but note that they would differ from market rate customers through both TRC+ and RIM results. The former would show more benefits based on the federal incentive increase, and the latter would show higher costs based on the larger ABP incentives available for LMI participants.

As shown in Table 14 and Table 15, rooftop solar, community solar, and solar+storage for both residential and commercial customers yield negative TRC+ net benefits and negative RIM net benefits. Therefore, the base rebate for these DERs is set at the base rebate floor.

For standalone storage on an RTP rate, TRC+ net benefits may be positive or negative depending on the assumed storage O&M cost, and RIM net benefits are positive. Based on these outcomes, we assume standalone storage with RTP passes the cost test screening, allowing us to continue calculating its Net Distribution Value, which is equals the distribution avoided costs minus the NEM-related distribution compensation.

As previously stated, we recommend compensating dispatchable DERs – such as energy storage – via performance-based Additive Services incentive rather than a Base Rebate due to the importance of dispatch timing. Developing an additive Services compensation mechanism now also has the benefit of preparing the utility and participants for the eventual goal of shifting all distribution-related compensation to Additive Services in order to differentiate incentive amounts by feeder.

Under current assumptions, we see a lifetime net distribution value of standalone storage that ranges from approximately $65 to $115 per kWh of storage capacity. However, this only provides an indication of the DER value – actual dispatch may result in higher or lower realized value over the DER lifetime. Accordingly, a performance-based incentive should directly use the avoided cost of distribution. We calculate the NPV avoided distribution cost for each utility, and levelize over the 25-year DER lifetime to get the Additive Services values listed in the tables. These are the recommended values per kW-yr to be used as the Additive Services incentive, and the expectation is that they would be paid out to dispatchable DERs based on average kW output across all the calls in a given year.

One quirk worth pointing out is that, under the current retail rate structures with flat distribution charges, the net-consumer behavior of energy storage leads to customers receiving negative distribution compensation through NEM (i.e. they pay more to charge than they get back in discharging). This idea was touched upon earlier in Section 3.5 as well. Consequently, we could consider adding these amounts into the distribution avoided cost before levelizing to gross up the value paid to participants, however, we have not done this here. Instead we prefer to keep the Additive Services incentive technology neutral – this distribution value is specific to technology round-trip efficiency, and traditional DR loads would not have any NEM distribution compensation (positive or negative) to account for. However, we note this as a future consideration – the negative existing distribution compensation values today mean their exclusion from the incentive value would only lead to some sharing of benefits between participants and ratepayers, but future time-of-use distribution rates could one day motivate stronger consideration of technology-specific Additive Service incentive levels.

Table 14. Compensation for representative residential customers (single family residential)

DER	Unit	TRC+ Net Benefits	RIM Net Benefits	Base Rebate Floor	Dx Avoided Costs	NEM Dx compensation*	Net Dx value	Base Rebate	Additive Services
ComEd									
Rooftop Solar	$/kW$_{DC}$	-$903	-$2,745	$300	$88	$388	-$300	**$300**	
Community Solar	$/kW$_{DC}$	-$201	-$1,898	$250	$88	$0	$88	**$250**	
Storage with Real Time Pricing	$/kWh capacity	$196 to $525**	$803	-	$47	-$39 to -$18**	$65 to $86	-	**$25 per avg kW†**
Solar+Storage (with RTP)	$/kW$_{DC}$ solar	-$1,834 to -$1,110**	-$1,458	$300	$115	$621	-$506	**$300**	
Ameren									
Rooftop Solar	$/kW$_{DC}$	-$391	-$2,431	$300	$100	$511	-$411	**$300**	
Community Solar	$/kW$_{DC}$	$311	-$1,382	$250	$100	$0	$100	**$250**	
Storage with Real Time Pricing	$/kWh capacity	$507 to $838**	$1,082	-	$74	-$43 to -$12**	$86 to $117	-	**$32 per avg kW†**
Solar+Storage (with RTP)	$/kW$_{DC}$ solar	-$1,030 to -$488**	-$1,030	$300	$150	$779	-$629	**$300**	

**NEM distribution compensation is estimated as the portion of bill savings tied to the base distribution delivery charge on a customer's bill*

***Depends on storage O&M cost assumption*

†Based on the distribution avoided cost, not expected performance. To be paid annually based on DER average kW output across all calls in that year

Table 15. Compensation for representative commercial customers (medium office)

DER	Unit	TRC+ Net Benefits	RIM Net Benefits	Base Rebate Floor	Dx Avoided Costs	NEM Dx compensation*	Net Dx value	Base Rebate	Additive Services
ComEd									
Rooftop Solar	$/kW$_{DC}$	-$186	-$2,163	$300	$88	$192	-$104	**$300**	
Storage with Real Time Pricing	$/kWh capacity	$491 to $639**	$721	-	$37	-$72	$109	-	**$25 per avg kW†**
Solar+Storage (with RTP)	$/kW$_{DC}$ solar	-$438 to -$211**	-$1,306	$300	$96	$258	-$162	**$300**	
Ameren									
Rooftop Solar	$/kW$_{DC}$	$328	-$277	$300	$100	$136	-$36	**$300**	
Storage with Real Time Pricing	$/kWh capacity	$827 to $975**	$817	-	$45	-$52	$97	**-**	**$32 per avg kW†**
Solar+Storage (with RTP)	$/kW$_{DC}$ solar	$293 to $521**	-$522	$300	$105	$159	-$54	**$300**	

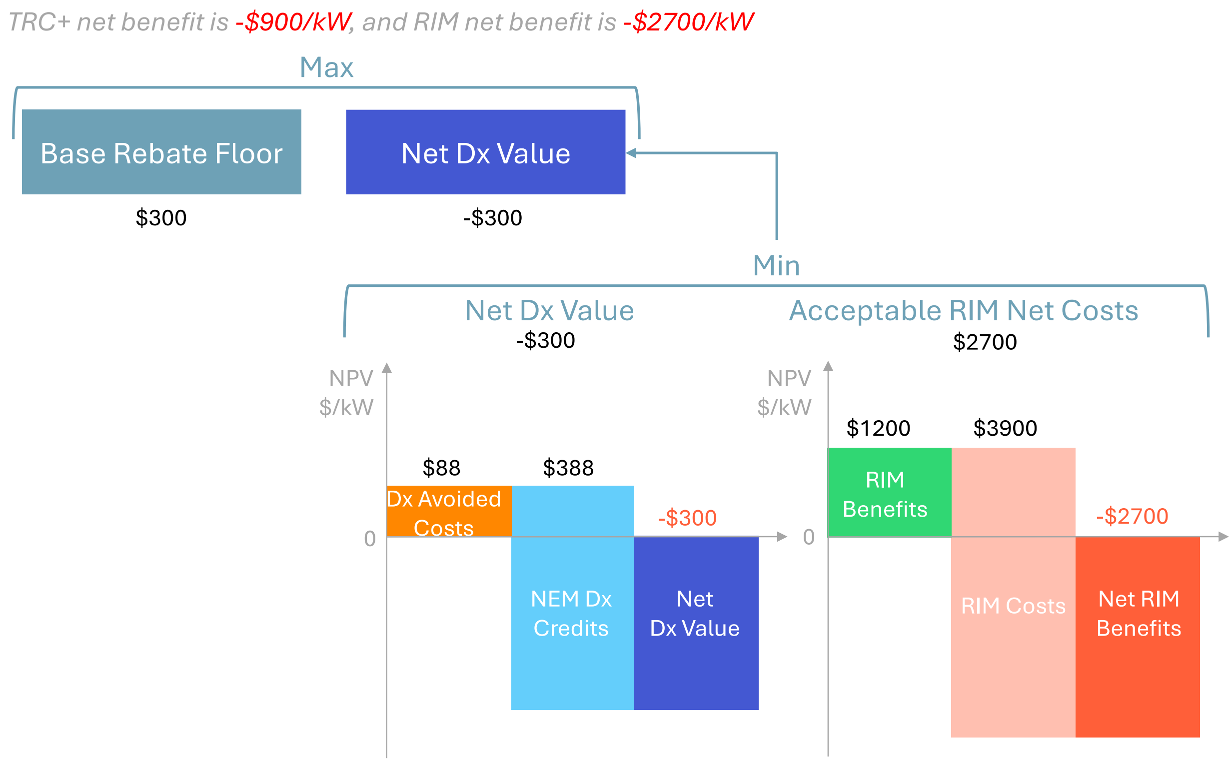
**NEM distribution compensation is estimated as the portion of bill savings tied to the base distribution delivery charge on a customer's bill*

***Depends on storage O&M cost assumption*

†Based on the distribution avoided cost, not expected performance. To be paid annually based on DER average kW output across all calls in that year

Figure 36 shows an example of the compensation analysis for ComEd single-family residential customers with rooftop solar, as illustrated using the compensation framework flow chart. While the base rebate for rooftop should be set at the floor given the TRC+ and RIM results, we went ahead and calculated the net distribution values and acceptable RIM net costs. The net distribution value for rooftop solar turns out to be negative because the distribution delivery credits that solar customers currently receive already exceed the distribution avoided costs.

Figure 35. Example Base Rebate calculation for ComEd single-family residential customers with rooftop solar



5.1.3 *Implementation considerations*

We developed the formula with enough flexibility to accommodate future updates. While its overall structure remains unchanged, the specific component values may be adjusted as new data or methodologies become available. The following list provides a few example scenarios where changing inputs or approaches would alter these values.

- <u>If customer retail rate changes</u>, the following components might change:
  - NEM Distribution Credits: If the distribution portion delivery portion of customer rates change or the retail rate structure is updated, the NEM distribution credits get updated, which will impact the Distribution Value.
  - RIM Total Costs: RIM total costs depend on customer bill savings. If customer retail change leads to higher customer bill savings, RIM total costs will decrease. As the result, RIM net benefits will change as well.

- If avoided costs change, the following components might change:
    - Modeled Distribution Avoided Cost: change in values or methodology of distribution avoided costs will directly impact this component and the net distribution value.
    - RIM Total Benefits: avoided costs of DER are the main benefits to ratepayers. Updates in avoided costs will impact RIM total benefits and consequently RIM net benefits.
    - TRC+ Net Benefits: avoided costs of DER are also the main benefits in the TRC+. Higher avoided costs increase the chance of the DER to pass the TRC net benefit threshold.
- If more non-energy benefits are added or quantified as more data become available, TRC+ net benefits will increase, which increase the chance of DER to pass the threshold.
- The TRC+ threshold X and RIM threshold Y can be modified depending on the state priority in balancing DER adoption with affordability and societal impact. As illustrated in Figure 33 and Figure 34, X and Y can be zero or negative depending on the state's choice on prioritizing ratepayer protection vs DER adoption. If the state wants to protect ratepayers, the threshold for RIM should be zero. If the state wants to prioritize DER adoption over ratepayer impact, the threshold for RIM could be negative.

The largest implementation challenge of this proposed formula is the inclusion of a performance-based Additive Services incentive on top of the upfront Base Rebate for distributed generation. However, we regard this challenge as an opportunity. Future distribution value and possible non-monetized benefits will require an incentive structure that is both time- and location-dependent. Setting this process up now so it is well-established once the need for more complexity arises will serve the state well.

Another challenge is program implementation for solar+storage use cases. Our analysis shows that additional compensation beyond the base rebate floor for solar+storage DERs would worsen affordability concerns for non-participants. Based on this, our inclination is to only allow participation in the proposed Additive Services program if a customer does not receive the Base Rebate. This could be challenging to implement though: it would require tracking customers closely and it misses out on the opportunity to leverage existing solar+storage systems to achieve targeted storage dispatch. Based on those challenges, it may be worth allowing participation in the Additive Services program regardless of pairing with solar and receiving the Base Rebate.

We note that the proposed call-based nature of the Additive Services incentive would not necessarily require storage customers to be on time-of-use type rates, which is the current requirement. However, we recommend keeping this requirement as it provides a daily price signal for dispatch operations to benefit the bulk electricity system and moves customers onto more cost-reflective rates with little-to-no concern of bill increases given their ability to arbitrage prices with energy storage.

5.1.4 Data needs and limitations

We have developed a detailed model package that calculates avoided costs, performs benefit-cost tests for the selected DERs, and derives values for the proposed compensation. Key data inputs for the model are listed in Table 16. More detailed description of the data sources can be found in Appendix E.

Table 16. Data needs for the proposed framework

Component	Data Source(s)
Capital Cost	NREL ATB[17]
Interconnection Cost	NREL ATB
O&M	NREL ATB
Federal Incentives	NREL ATB
Net Metering Payments	CEJA Section 16-107.6[18]
Adjustable Block Program REC Prices	ABP REC Pricing Model[19]
Base Rebate Floor	CEJA (Public Act 102-0662)[20]
Resource Generation/Dispatch Profiles	NREL System Advisor Models[21]
Reliability and Resiliency	Ameren and ComEd 2023 Reliability Reports, ICE Calculator[22], EIA Propane prices[23], Generator marketplaces[24,25]
Financial Risk Reduction from Fuel Price Volatility	RMI Utility-Scale Wind and Natural Gas Volatility[26]
Avoided Energy	NREL Cambium[27]
Avoided Generation Capacity	NREL Cambium
Avoided Monetized GHGs	NREL Cambium
Avoided Transmission	MISO and PJM transmission rates, conversations with Ameren, ComEd, and both RTOs
Avoided Distribution	Ameren and ComEd Refiled Grid Plans, FERC Form 1 filings, NREL Cambium
Losses	NREL Cambium, Ameren and ComEd

While the current modeling structure and dataset are sufficient for evaluating solar and storage, evaluating other DERs – such as wind, microturbines, and fuel cells – requires additional information. For these technologies, cost data and generation profiles are essential for evaluating TRC+ and RIM tests. Moreover, if a DER either saves or consumes fuels other than electricity, a separate model must be developed to capture the relevant avoided cost dynamics.

[17] https://atb.nrel.gov/electricity/2024/index
[18] https://ilga.gov/legislation/ilcs/documents/022000050K16-107.6.htm
[19] Appendix E REC Pricing Model for 2024 Long-Term Plan (April 17).xlsm
[20] https://www.ilga.gov/legislation/publicacts/102/PDF/102-0662.pdf
[21] https://sam.nrel.gov/
[22] https://icecalculator.com/build-model
[23] https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=W_EPLLPA_PRS_SIL_DPG&f=W
[24] https://www.electricgeneratorsdirect.com
[25] https://www.generatorsource.com/Natural_Gas_Fuel_Consumption.aspx
[26] https://rmi.org/wp-content/uploads/2017/05/RMI_Document_Repository_Public-Reprts_2012-07_WindNaturalGasVolatility.pdf
[27] https://www.nrel.gov/analysis/cambium.html

5.2 Alternative approach: no guardrails incentivization

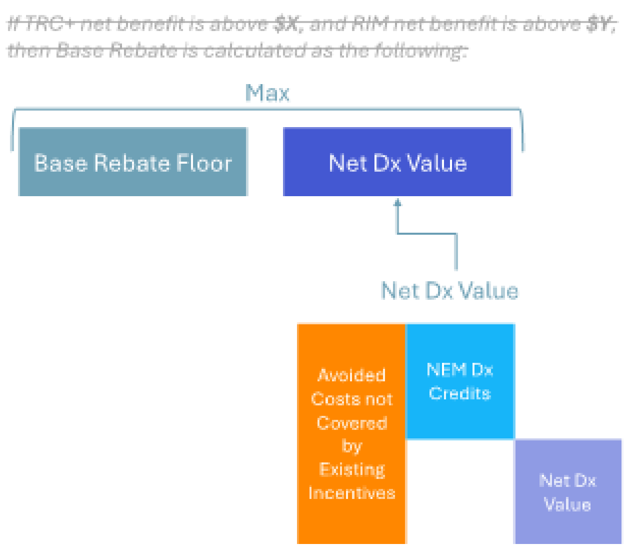
An alternative approach would be to base DER incentives solely on net distribution values. While this method would still comply with CEJA's requirement for the base rebate to cover system-wide grid services, it would remove the guardrails to protect ratepayers.

5.2.1 Rules/calculations defining the mechanism

Base Rebate

As illustrated in Figure 36, under this alternative framework, DERs are not required to meet any cost-test thresholds. In practice, this means the TRC+ threshold (X) and the RIM threshold (Y) could either be set to very large negative values or removed entirely. Similar to the proposed approach, the net distribution value is calculated as the difference between Avoided Costs Not Covered by Existing Incentives and NEM Distribution Credits. However, unlike the proposed approach, this net distribution value is not constrained by acceptable RIM costs, effectively eliminating any upper limit on how much ratepayers might spend in supporting DER incentives.

Figure 36. Base rebate compensation formula (alternative approach)



While the proposed method compensates dispatchable DERs (e.g., energy storage) through Additive Services, this alternative approach incorporates the net distribution value of storage into the base rebate. On one hand, this guarantees an upfront incentive for storage owners, providing a stable signal and upfront cashflow for investment. On the other hand, it does not ensure that storage systems will be dispatched in a way that optimally meets grid needs and delivers system benefits.

Additive Services

Under this framework, Additive Services for both solar and storage are zero.

5.2.2 Resulting DER compensation

Table 17. Compensation for representative residential customers under alternative framework)

DER	Unit	Base Rebate Floor	Dx Avoided Costs	NEM Dx compensation*	Net Dx value	Base Rebate	Additive Services
ComEd							
Rooftop Solar	$/kW$_{DC}$	$300	$88	$388	-$300	**$300**	-
Community Solar	$/kW$_{DC}$	$250	$88	$0	$88	**$250**	-
Storage with Real Time Pricing	$/kWh capacity	-	$47	-$39 to -$18**	$65 to $86	**$70**	-
Solar+Storage with RTP	$/kW$_{DC}$ solar	$300	$115	$621	-$506	**$300**	-
Ameren							
Rooftop Solar	$/kW$_{DC}$	$300	$100	$511	-$411	**$300**	-
Community Solar	$/kW$_{DC}$	$250	$100	$0	$100	**$250**	-
Storage with Real Time Pricing	$/kWh capacity	-	$74	-$43 to -$12**	$86 to $117	**$70**	-
Solar+Storage with RTP	$/kW$_{DC}$ solar	$300	$150	$779	-$629	**$300**	-

Table 18. Compensation for representative commercial customers under alternative framework

DER	Unit	Base Rebate Floor	Dx Avoided Costs	NEM Dx compensation*	Net Dx value	Base Rebate	Additive Services
ComEd							
Rooftop Solar	$/kW$_{DC}$	$300	$88	$192	-$104	**$300**	-
Storage with Real Time Pricing	$/kWh capacity	-	$37	-$72	$109	**$70**	-
Solar+Storage (no RTP)	$/kW$_{DC}$ solar	$300	$96	$258	-$162	**$300**	-
Ameren							
Rooftop Solar	$/kW$_{DC}$	$300	$100	$136	-$36	**$300**	-
Storage with Real Time Pricing	$/kWh capacity	-	$45	-$52	$97	**$70**	-
Solar+Storage (no RTP)	$/kW$_{DC}$ solar	$300	$105	$159	-$54	**$300**	-

Table 17 and Table 18 show the DER compensation using the alternative framework. The Base Rebate floor, Distribution Avoided Costs, NEM Distribution Compensation, and Net Distribution Value columns all contain the same values as the corresponding tables for the Recommended approach. Under this approach, the base rebate for solar and solar+storage is still at the base rebate floor. This is because rooftop solar and solar+storage see negative net distribution values, implying that the distribution-related benefits provided by these technologies are lower than the compensation they receive under NEM. Community solar sees positive net distribution value, although it is still lower than the base rebate floor.

Standalone storage with RTP retains its original net distribution value, but under this framework, it is compensated through the base rebate rather than through additive services. This compensation is based on the expected performance of the storage responding to real-time prices, since the lack of an Additive Services mechanism would remove a more distribution value-focused dispatch signal. The result is a lower incentive value than what can be offered when the value is based on avoided costs with actual performance dictating the fraction of this value paid to the DER. Because the Base Rebate cannot vary by location, we choose the low-end of expected value across example use cases to avoid overpayment.

5.2.3 Implementation considerations

Because this framework bases compensation solely on net distribution values, the factors influencing DER compensation are essentially a subset of those in the proposed framework. Components that would impact DER compensation includes:

- Distribution avoided costs: change in distribution avoided costs will directly impact the net distribution value.
- Retail rates: Change in distribution delivery rates will impact DER net distribution values. For storage in particular, all retail rate components – not just the distribution deliver portion – significantly influence dispatch decisions and performance outcomes, making them a key driver of compensation.
- Other non-monetized benefits: Inclusion and quantification of additional non-monetized benefits will increase additive service compensation.

Like the recommended approach, the alternative approach requires decision-making regarding the stacking of solar and storage incentives for hybrid systems. The considerations would be similar to the considerations listed in that discussion. Providing an energy storage rebate upfront strengthens the need to make sure storage operators see time-varying prices, so requiring storage-owning participants to be on real-time pricing or time-of-use rates would be essential.

It is also worth noting that this approach does nothing to prepare the state to later include time- and location-specific incentives for DERs as data improves.

5.2.4 Data needs and limitations

Compared to the proposed compensation framework, the alternative framework has simpler data requirements: it only needs accurate estimates of distribution avoided costs, current distribution compensation levels, and resource generation assumptions. However, this approach removes critical safeguards for ratepayers, particularly in how it compensates storage. Allowing storage to receive an upfront incentive without a corresponding performance requirement means that it may not be dispatched when the system most needs it and could even be dispatched at undesirable times.

6 Update process and future improvements

As previously stated, the proposed incentive values in Section 5 represent version 1.0 of this work. Accordingly, one of the most important aspects of the proposed formula is its ability to accommodate new or improved data sources and changing priorities of the state and stakeholders. In this section we demonstrate the ways in which the proposed formula is robust to a changing landscape of data availability, granularity, and quality. We also discuss the components feeding into the formula that would need to be updated at a regular cadence as well as possible triggers that would warrant outside-of-cadence updates or require more substantial formula revision.

6.1 Data updates on DER values

As mentioned in Section 5, the proposed compensation framework contains numerous components that can be updated as new data and methodologies become available. This is necessary as the Clean Energy Jobs Act (CEJA) requires that "the base rebate shall be updated annually based on the annual updates to the formula inputs."

Certain routine updates—such as revisions to customer retail rates, utility avoided cost values (when the underlying sources and methods remain unchanged), ABP REC prices, and additional non-monetized benefits—can be incorporated into the model without significant changes to the overall formula. These inputs naturally evolve over time and are updated by the respective agencies or utilities.

However, some changes necessitate more substantial revisions. One important component is quantifying DER values, which include distribution, transmission, generation, and non-monetized benefits. The methodology behind these calculations can be refined to reflect Illinois-specific grid conditions, higher spatial resolution (e.g., locational impacts within utility territories), and more accurate benefit assumptions for emerging DER technologies.

Many of the updates listed throughout this section anticipate the availability of data with more spatial variation than the system-wide values in this version 1.0 of the analysis. It is therefore important to note the potential modularity of our proposed formula. Analysis branches, all identical in framework to the recommended approach described in this report, can accommodate locationally differentiated factors to calculate local cost test results and compensation values at any reasonable scale. Within these branches, differing values by location would create a landscape in which DERs in more valuable locations would more easily pass the cost-effectiveness screening tests and receive higher compensation for participation. This is especially valuable for dispatchable DERs since they can take advantage of specific timing of local need and will already be using the Additive Services construct, which allows for spatial and temporal incentive variation.

6.1.1 Distribution system value

Distribution system data is the most important item to be updated in future versions of this incentive calculation. The extent to which DERs can be leveraged to provide value to the distribution system depends entirely on the information available on the distribution system and the confidence in that information. In each year the incentives are updated, this component should be the highest priority.

This analysis relies on combination of both a bottom-up approach for near-term distribution avoided costs and a top-down approach for long-term costs as a practical means of capitalizing on the strengths and covering the weaknesses of each approach on its own and to estimate a systemwide distribution value for DERs. In an ideal scenario, a bottom-up approach could be used exclusively with long-term forecasts of load growth and DER adoption on individual distribution facilities to calculate the location-specific distribution capacity value. Such an approach would allow for a more precise evaluation of benefits provided by DERs and recognize the significance of variation in facility-by-facility distribution system capacity needs. These findings may suggest that the structure of DER compensation for DERs eventually shift away from the flat Base Rebate value and take greater advantage of the more flexible Additive Services component for all technologies.

This location-specific, bottom-up long-term approach can be used as a north star for evaluating distribution value, but it is also useful to employ a walk-jog-run approach to reaching that goal.

The 'walk' stage for improving this analysis would be to first ensure that there is sufficient data and confidence in that data for applying the current, two-part approach. As noted in Section 3.1, the bottom-up approach relies on the utility distribution cost of service studies for the refiled grid plans and the top-down method currently reflects of average system costs. Though the methodology used by the utilities in their distribution cost of service studies is generally appropriate for estimating avoided cost values, there is minor variation between the utilities' approaches and we recommend reconciling these differences and establishing a single, commission-approved approach for future use.[28] The long-term distribution calculation, which mirrors part of the cost of service calculations to arrive at an annualized $/kW-year capacity value, should be adjusted accordingly.

The long-term distribution value is also currently based on an average cost of capacity due to limitations in applying a fully top-down approach where systemwide load growth is flat or declining. Unless forecasts shift to indicate sustained positive load growth, moving toward a more appropriate marginal value will require slightly more granular distribution cost data, broken out to regions within each utility's service territory where load is in fact increasing. The general principles of the top-down approach including a wider range of cost categories may still be maintained at this stage.

The 'jog' stage would move toward a fully bottom-up approach to estimating distribution costs, but it requires distribution planning to involve longer-term forecasts of costs and system needs – on the scale of at least 10-20 years out. While it is very difficult to fully project how customer load growth and component costs may change over such a long period, this challenge can be somewhat eased

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[28] As a minor note on these approaches, we specifically suggest that the approach for calculating and applying distribution line losses to determine a loss-adjusted value be examined and aligned for both utilities.

by grouping distribution facilities into different categories of expected need. Rather than estimating required investments for every individual feeder or circuit on a utility's system at first, a facility may be assigned for example as high, medium, or low capacity need and with an expectation of high, medium or low costs per unit of capacity, depending on factors such as labor and equipment costs for a specific urban or rural location and the relevant engineering considerations for upgrading the facility. Capacity costs for prototypical facilities within each category can then be assessed and applied to all facilities in that category.

Once this more granular level of cost assessment is achieved, the distribution avoided cost values will not only support more accurate evaluation of the actual benefits provided by DERs but will also inform an Additive Services compensation component that provides price signals to locate those DERs in the areas of greatest need. Use of the Additive Services compensation, which may vary over time and could be issued on more of a pay-for-performance basis, will also allow for values to be updated as forecasts evolve. This adaptation would also being more accommodating of the inherent uncertainty of the long-term forecasts.

The final, 'run' stage entails finally assigning distribution avoided cost value to individual distribution feeders or circuits based on the forecasted long-term conditions of those facilities. The utilities must have high levels of confidence in their forecasts for such estimates to be accurate and not provide false precision. This would be best coupled with a compensation mechanism that is based on real time DER performance and re-evaluated frequently to reflect changing system needs and incremental DER adoption.

6.1.2 Transmission

Like the current long-term distribution costs, the Network Transmission Service rates used as a proxy for transmission avoided costs in this analysis are more indicative of an average cost of capacity rather than a marginal cost. MISO and PJM explicitly noted this in our discussions, though did not yet have a means for providing marginal cost estimates in terms of capacity or an avenue for sharing the data necessary for us to calculate these value ourselves. However, both RTOs expressed an interest in exploring these values further to determine a more appropriate avoided transmission cost value for future use. Pursuing the key data will require closer collaboration between the RTOs and Ameren and ComEd in their respective transmission planning processes. Deeper collaboration in long-term transmission planning is expected to be beneficial to all parties involved even beyond the purposes of future avoided cost analyses. We strongly recommend encouraging such an outcome and continuing the discussions begun during this initial analysis to home in a marginal transmission cost value.

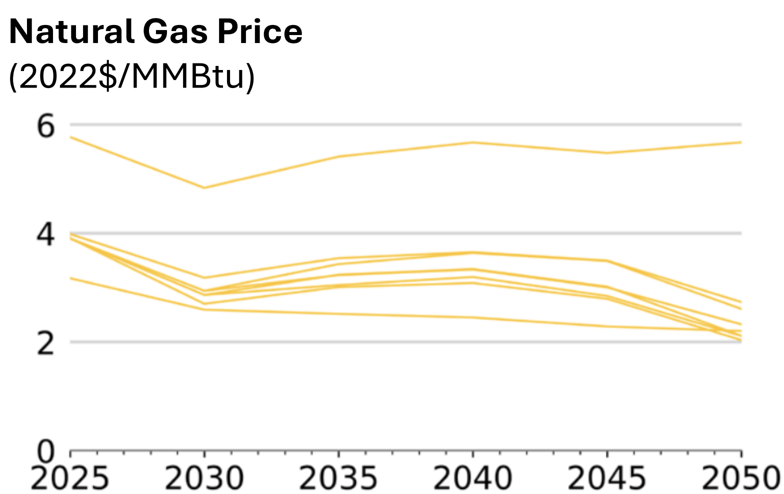
Additionally, there may be an overlap between transmission and generation capacity avoided costs, because Cambium capacity shadow prices can be driven by the cost of building additional transmission capacity. In such cases, generation capacity avoided costs become equivalent to transmission capacity avoided costs.

6.1.3 Generation

As detailed in Section 3.3, most generation-related avoided costs are derived from the NREL Cambium dataset. Although the NREL Cambium dataset serves as a valuable, publicly-available source for generation-related avoided costs, it does not fully capture Illinois-specific conditions for several reasons:

+ **Nationwide decarbonization goal**: The Cambium is a national model with decarbonation scenario targeting at the national level. While it technically includes existing state policies, it may not fully reflect long-term transmission and resource plan in Illinois and its surrounding areas.
+ **Non-IL specific resource costs**: Cambium inputs such as resource costs do not vary by locations and therefore don't reflect Illinois's actual economic factors such as labor costs and land costs, which can materially affect the true cost of renewable deployment.
+ **Import assumption**: The selected regions (MISO central and PJM west) in Cambium data heavily rely on imports in later years. These assumptions may not align with the actual resource adequacy and expansion plans of MISO, PJM, or Illinois itself.
+ **Gas prices**: While Cambium's documentation references national average natural gas prices (shown in Figure 37), it does not explicitly output or disaggregate prices for Illinois. This omission means that local factors—such as gas transportation and delivery costs—may not be fully captured in the model.

Figure 37. National average natural gas prices form Cambium across all scenarios[29]



An ideal data source for resource generation avoided costs would be based on a resource portfolio specifically tailored to Illinois's grid needs and goals. Such a portfolio would reflect current and future PJM and MISO market structures as well as local factors like resource costs, fuel prices, and

[29] The documentation didn't specify which line comes from which scenario. We assume that the higher prices come from the "high natural gas price" scenario. Cambium 2023 Scenario Descriptions and Documentation. page 12. https://www.nrel.gov/docs/fy24osti/88507.pdf

fossil fuel plant retirements. If publicly available, market prices from PJM and MISO's long-term plans could be a better reference than Cambium data.

E3 was recently hired by the Illinois Power Agency (IPA) to support development of its Electricity Procurement Plan, Long-Term Renewable Resource Plan and a Resource Adequacy study. Some of Illinois-specific resource plans and associated market price forecasts coming out of this project could serve as valuable data sources for calculating generation avoided costs in the future.

One important gap in Cambium is its lack of explicit grid reliability or resource adequacy assessment. Instead, Cambium relies on heuristics to develop a planning reserve margin (PRM) and allocate annual capacity costs.

For example, Cambium's PRM is based on only one year of weather and load data, even though variable generation strongly depends on weather conditions. In addition, Cambium allocates generation capacity prices to the top 100 net load hours (calculated as total load minus storage charging and variable generation). This "net load" approach overlooks that energy storage dispatch tends to flatten the net peak over longer intervals. As storage penetration grows, its incremental capacity contribution often diminishes, which the simple net-load allocation fails to capture.

A more robust method would use a probabilistic reliability framework—particularly a loss-of-load expectation (LOLE) model—to accurately determine both the capacity value of each resource and the allocation of annual generation capacity avoided costs. The Federal Energy Regulatory Commission (FERC) recently approved MISO's "direct loss-of-load" (DLOL) method for resource capacity accreditation.[30] This approach measures a resource's ability to serve load during scarcity hours in the LOLE model.[31] Ideally, future developments of capacity avoided costs and DER capacity contributions should align with this methodology implemented in MISO.

6.1.4 Non-monetized benefits

While we do not propose to directly compensate for any non-monetized benefits, updating inputs to quantified non-monetized benefits will change the results of the proposed cost-effectiveness screening tests. For example, a growing reliability value could push a TRC+ test showing net costs to show net benefits, and therefore be eligible for an incentive. With this value in mind, we briefly explain some possible updates to non-monetized benefit data in the coming years, though some commentary on these future updates has already been discussed in Section 3.7.

Reliability values stand to become more representative of the customers they represent for two reasons: more localized outage data and more regionally appropriate VOLL estimates. Localized outage data is collected by the utilities and reported for their worst performing circuits in their annual

[30] https://www.rtoinsider.com/90464-ferc-approves-miso-probabilistic-capacity-accreditation/
[31] MISO, "Resource Accredatition White Paper (Version 2)", February 2024; https://cdn.misoenergy.org/Resource%20Accreditation%20White%20Paper%20Version%202630728.pdf

reliability reports,[32] but the small impact of the reliability benefit on the final compensation formula did not warrant location-specific consideration for this first version of the incentives. In future versions, reliability benefits would appropriately vanish for highly reliable sites and increase for outage-prone locations, perhaps with emphasis added through implementation if those locations overlap with EJ communities. One complaint we heard from multiple stakeholders was that, though the DOE ICE calculator is the industry standard for VOLL estimation, it is not representative of customers in Illinois. The commissions has, in fact, instructed ComEd and Ameren to derive their own estimates of VOLL, but the timeline for completion of this process is unclear. Updates to the VOLL numbers in the model or to the SAIFI, SAIDI, and CAIDI values could all be handled within the existing model architecture.

Financial risk reduction due to a decrease in exposure to fuel price volatility and reduced methane leakage should be reevaluated periodically as well. Specifically, if grid marginal resources and energy storage dispatch are both tracked on an hourly basis, the amount of gas generation avoided by energy storage could be quantified well enough to compensate storage resources for future price risk reduction. However, targeting this value may require an expanded Additive Services dispatch signal that includes more hours coincident with marginal gas generation.

Another possibility is that future DER solar compensation could change enough to alter the RIM test result, in which case this benefit could be considered as an Additive Service for DG – though we find this future unlikely.

Proximity to MHDV charging infrastructure is a good example of a benefit that has no quantifiable value today but may have substantial quantifiable value in the future. Specifically, once plans for such infrastructure exist and associated costs are quantified, the avoided distribution cost should reflect these costs when updated. This means the potential benefit will show up in an existing part of the model (distribution avoided cost) without requiring consideration and compensation outside of the monetized benefits list. As with other distribution deferral opportunities, timing will be a challenge if potential infrastructure costs are not identified appropriately far in advance of needing to start building the project.

6.2 External triggers for update

As stated by CEJA, the finalized compensation mechanisms will be updated on an annual basis to reflect data updates and changing conditions of the electrical system. Here, we call out a few specific ongoing and possible future processes in Illinois that could have large impacts on our analysis results. We discuss each below and whether off-cycle updates to this analysis would be warranted by developments external to this proceeding.

[32] 2023 reports available here: https://icc.illinois.gov/api/web-management/documents/downloads/public/industry-reports/2023%20%20Ameren%20Illinois%20Electric%20Reliability%20Report.pdf
and here: https://icc.illinois.gov/api/web-management/documents/downloads/public/electric-reliability/ComEd%20Report%20YE%202023.pdf

6.2.1 Participation of other DER technologies

Throughout this report, we focus our consideration of the Additive Services incentive on how it could be applied to incentivize distributed energy storage. However, the recommended incentive structure is intended to be technology agnostic: a kW of power provided to the grid during a program call is equivalent whether coming from energy storage, flexible load (e.g. DR), or an EV discharging to the grid (V2G). Accordingly, the proposed program could also allow participation from other dispatchable DER technologies. In the interest of standing up a simple program before expanding to all technologies, it may be wisest to limit participation to energy storage at first, but participation of other technologies should not lag far behind.

Each additional technology allowed to participate in Additive Services compensation would face hurdles, but none that cannot be overcome soon if not today. Participation from DR would require a process for determining baseline usage in the absence of incentive signal response, but this is a common hurdle for DR programs, and the ubiquity of advanced metering across the state only improves the accuracy of baselining efforts. V2G implementation would be more complex: V2G capabilities are in their infancy, with most EVs and chargers only able to curtail load but not export power to the grid. Additionally, we recommend addition of EV-specific use cases to the existing analysis, or at least careful parsing of EV rates, to ensure that EVs do not already receive compensation for their value to the distribution system.

6.2.2 Grid Plan final Orders

As previously mentioned, many inputs used for estimating distribution avoided costs are directly from the Grid Plans.

On December 19, 2024, the ICC approved ComEd and Ameren's refiled grid plan with modifications on their requested rate increase.[33] The timing of this order and this analysis is challenging: any substantial changes to the Grid Plans coming out of these Orders will immediately render some of our analysis out of date.

At the time of this writing, the scale of change stemming from the Grid Plan orders is uncertain. The approval of ComEd's long-term distribution system investment plans and Ameren's Marginal Cost of Service Study (MCOSS) means our assumptions on avoided distribution costs likely align with the approved Grid Plans. However, changes to each utility's revenue requirement and to Ameren's return on equity will likely affect future delivery charges, which may impact alignment of actual rate escalation with our assumed 2.5% annual retail rate escalation.[34]

Additionally, the Grid Plan orders required Ameren and ComEd to work together to "refine a common, transparent statewide MCOSS methodology for use in future grid plan proceedings."[35] This indicates

[33] See https://www.illinois.gov/news/press-release.30763.html and https://www.illinois.gov/news/press-release.30764.html

[34] Detailed order can be found in https://www.icc.illinois.gov/docket/P2024-0181/documents/359318/files/629460.pdf for ComEd and https://www.icc.illinois.gov/docket/P2024-0238/documents/359319/files/629463.pdf for Ameren

[35] https://www.icc.illinois.gov/docket/P2024-0238/documents/359319/files/629463.pdf. Page 217

the Commission's intent to further improve and standardize distribution avoided costs. The effort to standardize methodologies may benefit from the initial investigation and collaboration undertaken during this value of DER analysis and should in turn ease the path for iterating upon and updating inputs to the proposed compensation framework.

Ultimately, whether to update the analysis given the new grid plan orders will come down to a decision based on the expected impact to this study and the expected time required to make an update. Updates to numbers without updates to methodologies are generally easy to plug in and use for reevaluation, but changes may also be deemed too small to be worth an update. We invite feedback from stakeholders who were more closely involved in the utilities' Grid Plan filings on which aspects of the new plans could significantly affect DER compensation under this framework.

6.2.3 Iterative alignment with Adjustable Block Program assumptions and Non-wires alternatives processes

The base rebate and the ABP REC prices[36] are closely linked: changes in one can affect the other. Because ABP REC payments come from ratepayer funds, they contribute to RIM costs and therefore impact the cost-test screening as well as the incentive cap. Conversely, the base rebate can influence how REC prices are set, since those prices are calculated as the difference between the financial requirements of distributed solar and existing compensation streams, which includes base rebate.

Although the REC price model and this analysis both rely on similar input categories, they draw on different data sources and underlying assumptions. Below are key areas in which these differences arise:

- **Resource costs**: In the ABP REC model, resource costs come from the 2021 NREL ATB benchmarking report which provides national cost average for solar projects.[37] By comparison, this analysis uses cost projections from the 2024 NREL ATB, which forecast slightly lower prices for solar and storage due to anticipated cost declines in or after 2025. We also adjusted the costs to reflect Illinois specific labor and land costs. Overall, the difference in costs is mainly the result of using more recent NREL ATB versions.
- **Revenue and cost sharing**: In the ABP model, there is an explicit return for developers, and a portion of NEM credits goes directly to them—reflecting certain financing structures where developers retain partial ownership of projects. This analysis, however, treats participant costs (e.g., system installation, O&M) as shared between the developer and the customer, without specifying a particular return on investment.
- **Energy supply credits**: The ABP model calculates energy supply credits by looking at historical locational marginal prices (LMPs)—using a five-year average—then escalating them by 1%. Although straightforward, this approach may not capture future market changes or evolving resource mixes. This analysis, on the other hand, derives energy

[36] Latest model available at Appendix E REC Pricing Model for 2024 Long-Term Plan (April 17).xlsm
[37] https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/appendix-d-2024-plan-filed-with-icc-20-oct-2024.pdf

avoided costs from the NREL Cambium dataset, which incorporates long-term changes in resource portfolios due to changing decarbonization targets, evolving resource costs and load changes.

+ **Retail Rate Escalation**: The ABP model uses a flat 1% annual increase in retail rates. While simple, this may not fully reflect changes in generation and distribution costs or emerging grid modernization initiatives. This analysis, on the other hand, aligns energy supply cost escalation with Cambium's shifting resource portfolios and aligns delivery cost escalation with utility-specific distribution avoided costs.

We have discussed these assumption differences with the IPA, and both parties agree that given the different purposes of each analysis—and their distinct update timelines—these variations are understandable. Currently the ABP's REC price model assumes a $250/kW base rebate for solar. Since this analysis concludes that solar base rebate should be set at the floor, it may have limited near-term impact on the ABP.

We also note that the dependence of our results on the ABP incentives lies only at the cost-effectiveness screening level. As a result, updates to ABP will change screening calculations, but may not have any impact on results, which depend more directly on distribution avoided cost and NEM compensation.

The IPA is in the process of updating its REC model, which could potentially integrate some of the assumptions and cost trajectories highlighted here. Looking ahead, both the base rebate and additive service rebates should be revisited periodically to reflect evolving IPA assumptions, cost forecasts, and policy goals. Gradually aligning these analyses when appropriate can help ensure that compensation remains equitable, cost-effective, and responsive to Illinois's clean energy objectives. However, we do not find it necessary to update this model off-cycle just to hasten alignment with IPA cost assumptions.

We also acknowledge the overlap that exists between the proposed Additive Services mechanism and existing utility Non-wires Alternatives programs. These nascent programs use a Request for Proposals (RFP) process to solicit non-infrastructure solutions to grid needs. We expect the grid needs identified by non-wires opportunities to be some of the same grid needs identified and valued by distribution avoided costs as these avoided costs improve over time in spatial resolution. Based on this overlap, it is possible that non-wires programs merge with the Additive Services mechanism over time, creating an ability for more and smaller projects to provide non-wires value without the bespoke RFP process used today. It will be years before distribution avoided costs have spatial granularity on par with non-wires opportunity identification, and they may never match the same level of detail, but there is value in starting to understand today how these programs may interact over time.

6.2.4 Evolving incentives for, and deployments of, energy storage

As shown in Section 4.2, even with compensation for distribution value, standalone storage often faces a significant "missing money gap" from the participant's perspective. In other words, the costs of installing and operating a storage system typically outstrip the benefits a customer receives through existing incentives and rate structures. This gap suggests that the current framework may undervalue contributions from load-shifting DERs, which can provide considerable benefits to both the state and ratepayers.

Adopting time-varying rates that better align delivery charges with peak demand periods could help close this gap by allowing storage to earn more through NEM when it actively reduces system peaks. Depending on the evolution of time-varying rates, this alone could be enough to meaningfully close that gap, and there would be appeal to NEM and rate design being the avenue through which distributed generation and distributed energy storage receive compensation for their value to the bulk grid.

Alternatively, programmatic approaches, similar to our suggested performance-based implementation of Additive Services, offer a more explicit way to compensate storage owners for their capacity to support the grid. Under this approach, participants receive a performance-based incentive (e.g., a set dollar amount per kilowatt) tied to the average battery discharge during a series of demand-response events each year. If such a structure is the preferred strategy, it could even be nested within the Additive Services construct outlined in this framework. However, an open question remains regarding the language of CEJA permits designing compensation specifically to fill this missing money gap through the current process, or if further legislative or regulatory action is needed.

We also note that the best path for providing energy, capacity, and transmission value to the grid may be through bulk system investment instead of DERs. Utility scale storage can provide all of those values and leverage economies of scale that DER applications cannot access. SB3997, passed by the Illinois legislature at the start of 2025, directs the IPA to develop plans for procuring energy storage, which will lead to additional utility scale deployment. Our analysis suggests this deployment will be beneficial for the state, but we also recognize the competition for value between bulk and distributed resources: A portfolio that includes more storage resources soaks up the operation value that storage provides, decreasing the value for each next incremental amount of energy storage deployed at any scale. Because the proposed Additive Services compensation is based only on distribution value, increasing bulk grid storage penetration would not impact the compensation amounts. However, increasing bulk grid storage will reduce energy, transmission, generation, and GHG avoided costs, altering the results of the cost-effectiveness screening step used to decide if an incentive should be provided at all.

Ultimately, our analysis does not optimize across alternatives and cannot be used to recommend deployment of energy storage at the DER scale or the bulk scale, but it can tell us that distributed energy storage developers have little incentive to install a technology that could be beneficial for the state. Regardless of the mechanism and the policy decision of what deployments to promote, any change to the incentives available to distributed energy storage or any change to utility scale energy storage deployment would alter the screening tests used to determine whether compensation should be provided to distributed energy storage. We again contend that while impactful, changes to storage incentives or bulk grid deployments would be unlikely to warrant an off-cycle update to this study.

6.2.5 Retail rate reform

Current residential rate designs recover the majority of costs through volumetric (per kilowatt-hour) charges. While this approach was historically seen as encouraging conservation, it now creates misalignment with several emerging energy goals. A substantial share of utility expenses—such as energy efficiency programs, distribution infrastructure, and transmission systems designed for peak demand—are largely fixed and do not vary with individual customers' monthly electricity usage. Nevertheless, they are bundled into volumetric rates.

As noted above, flat volumetric rates fail to signal dispatch for and compensate energy storage, while adoption of time-varying rates that appropriately reflect costs can correct this. Also, high electricity prices discourage electrification by making electric heating and EV operation more expensive than they would be under rate designs that more accurately reflect cost causation.

Moreover, by basing most cost recovery on volumetric consumption, customers with on-site generation such as rooftop solar can significantly reduce their bills—even though many of the costs they avoid are not actually reduced by their DER contributions. For example, these customers still rely on the grid for backup power and for exporting excess electricity, yet they pay proportionally less for shared programs and infrastructure. This dynamic raises equity concerns for non-participating ratepayers, who may end up carrying a larger share of grid costs.

Rate reform offers a path to resolve these issues and support the modern policy goals of grid reliability, affordability, and decarbonization. Increasing the portion of residential cost recovery through fixed charges (or more refined demand charges) would reduce volumetric rates, ensuring that all customers contribute fairly to the upkeep of grid infrastructure and shared services. Likewise, TOU rates could send more accurate price signals about the periods when DER dispatch has the greatest system value, incentivizing technologies like battery storage to discharge during peak hours. By restructuring rates to reflect real cost drivers, utilities and regulators can create a more equitable system that encourages beneficial electrification, ensures appropriate cost-sharing, and supports continued growth in distributed energy resources.

As changes occur, it will be important to assess the likely impact of these changes on the DER compensation recommended by this study. For example, lower volumetric rates may reduce NEM distribution compensation, which could increase compensation amounts suggested by this study. While changes to rate design could substantially change analysis results, these changes also tend to occur slowly. As such, we do not see a need for off-cycle updates to this study based on rate design developments.

7 Stakeholder Engagement

Stakeholder engagement was a critical part of this study. As previously noted, this engagement did not result in broad consensus, but it did inform the proposed framework and mechanisms in this report. Our outreach and interaction with various stakeholder groups included:

+ 205: Total minutes of discussion during each workshop in Series 2,
+ 97: Average attendees in each Series 2 workshop,
+ 11: Written comments received,
+ 20: Meetings with utility and RTO representatives to establish methodology and values for distribution and transmission avoided costs; and
+ 6: 1:1 feedback meetings held.

We thank the stakeholders for their commitment to providing thoughtful and actionable feedback throughout the Series 2 workshops and in written and oral feedback. In this section, we summarize the Series 1 and Series 2 workshops, including dates of the workshops and key topics covered in them. We also direct the reader to Appendix A, in which we present a series of tables listing key feedback from stakeholders, the extent to which that feedback has been addressed, and our brief notes in response to the feedback.

7.1 Workshop Series 1 Summary

Workshop Series 1 took place from August to December 2023 with a diverse set of stakeholders convened in an open forum. It was led by Enernex and in total comprised of six meetings. Stakeholders were invited to the meetings via email and via the ICC’s website. The email database included 150 people and was used to send out email invitations to all meetings in both Workshop Series 1 and 2.

The overall objectives were to identify relevant topics and solicit concepts, seek stakeholder feedback on the statutory objectives of the DER valuation process, and collect insights that will guide the compensation framework development that will at the center of Workshop Series 2. Discussions across the six meetings covered how the base and additive services rebates are defined in the CEJA language, the types of DERs, existing DER rebates, the array of variables that impact a DER's value, potential risks, compensation approaches used in other jurisdictions, and proposed inputs and methodologies for developing a statewide DER base and additive services compensation framework in Illinois.

Table 19. Workshop Series 1 details

Meeting #	Date	Overview
Workshop 1: Introduction and Scoping	August 11, 2023	• Workshop Series Kickoff and high-level overview of the workshop series process • Focused on ensuring that the first workshop series would "identify relevant topics and seek stakeholder feedback on the statutory objectives of the DER valuation process."
Workshop 2: Foundational value of DER & CEJA requirements	September 8, 2023	• Investigation into the value of and compensation for DERs, including a review of best practices in calculating DER benefits • Review of the full value of DER and the way each component of that value is or is not otherwise compensated.
Workshop 3: Base Rebate and Valuation Methodologies	September 29, 2023	• ComEd presented current DER compensation assumptions and examples of how locational, temporal, and technological variables impact DER valuation. The scenarios demonstrated the challenges of defining a "base" value for systemwide services without consideration of these variables. This led to some discussion regarding the systemwide and additive services definitions in the CEJA language. • The Joint Solar Parties presented compensation options tied to a range of potential values. Discussion demonstrated that values will vary before and after threshold date, by technology, by customer type, and by systemwide or additive value.
Workshop 4: Locational Value of DER	October 20, 2023	• Ameren presented its perspective on determining the calculation for systemwide base rebates, particularly concerning the existing value streams of DERs and the distribution system. • Joint Solar Parties presented several DER valuation approaches used in CA, CT, NY, MD, and NH • Sunrun on behalf of Joint Solar Parties also presented a case study from Hawaii that showcased increased hosting capacity of DERs on smart inverter settings.
Workshop 5: Additional Services of DERs	November 17, 2023	• ComEd presented on distribution line losses, voltage optimization, and smart inverter voltage control settings, and shared potential concepts for base rebate formula • Vote Solar presented best practices and recommendations for DER compensation • CPower analyzed the value of DER additive services and considerations for the compensation of additive services
Workshop 6: Remaining Topics and Summary	December 8, 2023	• Brattle Group presentation highlighted incentivizing behind-the-meter storage and emerging practices for leveraging customer adoption of storage • Joint Solar Parties discussed methods of calculating base and additive rebates by quantifying the benefits that DERs provides to the utility • Ameren presented a suggested strawman for DER compensation and included lessons learned from previous efforts of calculating the value of DERs.

The following describes the key discussions and takeaways from Workshop Series 1.

Types of DERs

Stakeholders identified several DERs that encompass a variety of technologies that provide decentralized power generation, storage, and grid services. These include solar photovoltaic (PV) systems, wind turbines, battery energy storage, electric vehicles, biofuels, fuel cells, microturbines, demand response mechanisms, and microgrids.

Requirements for Base Rebate

In Workshop 2 and 3, stakeholders focused on the specific requirements for a base rebate that must be met. The rebate must be consistent across the state and should not vary by customer type, location, or other variables. Furthermore, the rebate levels must not fall below existing base rebates for distributed generation (DG) and storage. Currently, DG base rebates are set at $250 or $300 per kW. For storage, base rebates are $250 or $300 per kWh. Utilities serving over 200,000 customers must provide these rebates to DER owners if the system capacity is 5,000 kW or less, is located on the customer's side of the meter, and is interconnected to the electric distribution facility with a smart inverter installed.

Requirements for Additive Services Compensation

In addition to the base rebate, additive services compensation is proposed to address the value DERs provide beyond the baseline. This compensation can vary based on factors such as location, time, technology, and performance characteristics. It must reward DER owners for delivering value above and beyond the base rebate and can take the form of a one-time payment or ongoing performance-based incentives.

Key Takeaways – Utility Perspectives

Utility perspectives highlight the dual priorities of motivating DER adoption while mitigating potential adverse grid impacts. Ensuring customers see a return on their DER investment is critical, but compensation structures must remain flexible to avoid overcompensation that could burden nonparticipating customers. Key proposed approaches include using upfront additive service rebates for small systems to encourage beneficial site selection, applying de-rating factors to account for project variability, and implementing performance-based compensation for larger systems tailored to local needs. Additionally, a probabilistic approach to valuation could assess the likelihood of DERs providing grid capacity relief.

Key Takeaways – Valuation Considerations

Valuation considerations underscore that the current base rebates for DG and storage establish a minimum threshold for any proposed changes. The value of a DER is highly dependent on geographic, temporal, and performance-related characteristics, which are all considerations for the value of additive services. While DERs can offer positive grid value, improper placement or control may lead to adverse impacts, such as overvoltage. Moreover, all DERs will likely see their value diminish with increasing saturation; an effect that will either compound or counter the evolution of value to the distribution system over time, which will differ depending on DER dispatchability. An additive services compensation structure must balance consistency with flexibility, incorporating multiple variable inputs while adhering to a standardized methodology.

Key Takeaways – Implications to Future DER Programs

Design considerations for DER programs aim to achieve several key goals. DERs should be fairly compensated for their value in a manner that is simple for customers to understand. The design should aim to be cost-effective and administratively manageable. These principles are essential for fostering a robust and sustainable behind-the-meter DER ecosystem that benefits both individual participants and the distribution system.

7.2 Workshop Series 2

Workshop Series 2 was led by E3 and Viridis Consulting and took place from March to December 2024. While originally three meetings were planned, ultimately four meetings were convened.

Workshop Series 2 was distinct from Workshop Series 1. While Series 1 was designed to solicit concepts, promote discussion and brainstorming, and collect insights that will guide the compensation framework development, Series 2 was led by the technical team developing the compensation model and the meetings within Series 2 paralleled the development of the model, inputs used, and strawman, ensuring that stakeholders were part of the process and could actively engage and provide input in real time.

Workshop Series 2 aligned with E3's development of the valuation model and these core objectives served to support both E3's work and the flow of the meetings.

- Identify the framework elements, inputs and methodologies that are relevant to the development of a DER valuation strawman proposal.
- Gather stakeholder input, document the process, look for consensus where achievable, and record input received.
- Consultants develop a Final Report that provides ICC staff with the guidance needed to open a rulemaking proceeding prior to the 12/31/24 Threshold Date.

Table 20. Workshop Series 2 details

Meeting #	Date	Overview	# of Attendees
Workshop 1 Kick-Off	March 6, 2024	• Summarized Series 1 • Presented avoided cost methodologies • Discussed Illinois-specific context that impacts avoided costs and compensation framework.	104
Workshop 2 Methods of Valuing/ Compensating DERs	July 10, 2024	• Presented on avoided costs development and the Benefit/Cost Analysis (BCA) model.	101
Workshop 3 Draft compensation framework	October 16, 2024	• Presented draft compensation frameworks • Collected feedback and other input for the final report.	93
Workshop 4 Updated compensation framework	December 11, 2024	• Presented analysis on suggested mechanisms, proposed formulas, and process to update the base rebate and additive services compensation structure • Collected input for the final report.	89

The following describes the key discussions and takeaways from Workshop Series 2.

Meeting 1 introduced the workshop series, E3's objectives, and the approach to developing a comprehensive DER compensation framework. Key discussions focused on valuing avoided costs, including distribution, transmission, generation, capacity, and greenhouse gas benefits, while addressing challenges such as evolving energy systems, shifts in peak demand, and customer-sided storage. Two methodologies for calculating distribution costs—top-down and bottom-up—were debated, with an emphasis on transparency, accuracy, and location-specific factors like marginal line losses and resilience.

The framework's principles aim to align DER compensation with ratepayer value, minimizing cost shifts and ensuring affordability. Avoided costs must be marginal, long-term, and technology-agnostic to adapt to future grid needs. Data requirements include planned distribution investments, load forecasts, energy price forecasting, and transmission costs, with inputs sourced from utilities and the NREL Cambium database. Stakeholders provided feedback on methodologies, forecast needs, and hardware requirements, setting the stage for future discussions and rule-making processes.

Meeting 2 centered on E3's presentation of a DER compensation framework and a discussion on the framework elements, data inputs used, and the different ways to quantify non-monetized value.

E3's presentation introduced a benefit-cost model which included emphasizing the need to balance customer adoption, value realization, and cost management. Various cost tests were discussed, including participant cost tests, total resource cost tests, and ratepayer cost tests, with a consensus on the importance of considering multiple perspectives rather than relying on a single test. The discussion highlighted the relationship between revenue requirements and revenue collection when designing DER incentives, which include programs such as net metering, adjustable block programs, base rebates, and additive services. Solar and storage installations' impacts on grid load and value were explored, noting that storage requires dispatch signals to provide grid value effectively.

The meeting also addressed avoided costs for transmission and distribution across states like California, Washington, and New York, examining top-down and bottom-up approaches. Allocation factors for peak load hours and net present values for solar and storage were presented, alongside insights from the Cambium and MISO datasets on energy generation capacity and greenhouse gas (GHG) reduction goals. Discussions covered the variability of energy prices with renewable energy integration, annual capacity and GHG values allocation to peak net load hours and avoiding double counting. The concept of Virtual Power Plants (VPPs) was discussed as a strategy to enable solar and storage owners to support the grid during peak demand for compensation. Challenges in calculating avoided distribution costs, determining incentive amounts, and managing administrative burdens were discussed, with suggestions for using combined methodologies and simplifying payment mechanisms for smart inverter incentives.

Meeting 3 addressed key aspects of valuing and compensating DERs, including distribution and transmission values, non-monetized benefits, and the proposed DER compensation framework. Discussions highlighted challenges in methodologies, such as the limitations of a top-down approach with public data and the potential overestimations of an average cost model. A bottom-up approach was emphasized for its ability to capture location-specific costs tied to increasing load. Stakeholders expressed concerns with the use of system capacity versus load in calculating marginal costs, and possibly overlooking locational impacts and the true value of DERs in reducing peak loads. The meeting also noted that avoided transmission costs rely on load-serving entity obligations, while initial placeholder values for the NTS rate might overstate deferrable or capacity-related benefits.

E3’s proposed compensation framework was developed to take into consideration minimizing cost shifts between participants and non-participants while balancing customer adoption and societal costs. Other key considerations included valuing reliability and resiliency without additional compensation, integrating environmental justice, and exploring locational benefits of controllable flexibility in the future. Challenges in quantifying voltage regulation, transmission value, and avoided costs were acknowledged, alongside the decreasing value of solar as grid decarbonization progresses. Stakeholders were urged to provide detailed models and granular data to refine analyses and ensure equitable DER compensation aligned with system benefits and policy objectives. At this meeting it was announced that a 4th meeting would be added as part of this Workshop Series and it is scheduled for December 11, 2024.

After the meeting, stakeholders requested the actual models used in the development of the compensation framework. E3 released and posted online the Benefit-Cost Analysis Tool, the Avoided Cost Calculator and the outline of the Final Report in November, prior to Meeting 4 taking place.

Meeting 4 started with a detailed review of each of the Objectives of the Investigation with a focus on certain objectives that serve as areas of focus for the content presented at this meeting. Next, E3 summarized all stakeholder feedback received to date and noted how E3 addressed each individual comment. Each comment was categorized as “revision made,” “E3 revised – no revision made,” or “To be considered further.”

Key discussions focused on improving data granularity to better target spatial and temporal incentives and the need for clarity on resiliency calculations and avoided fuel price volatility risks. Real-time pricing was emphasized as a superior signal for grid value compared to time-of-use rates. Concerns were raised about the interplay of avoided costs, base rebates, and rack prices, as well as the need to refine the understanding of "non-monetized" benefits and allocate resiliency benefits more equitably.

Stakeholders highlighted the importance of addressing cost shifts, especially for low-to-moderate-income (LMI) customers, and improving data to quantify non-energy and societal benefits, such as outage impacts and environmental justice considerations. The model's flexibility to integrate new data was noted, but timing mismatches with grid plan litigation and upcoming commission orders pose challenges. The timeline includes a draft report by December 31 to ICC, a final report released to the public in January, and an eight-day comment period before rule drafting begins.

8 Summary of Recommendations

This report has proposed a framework for understanding and evaluating DER benefits provided to the grid and more broadly to the State of Illinois. Based on this framework, we proposed a DER compensation mechanism to supplant the existing Base Rebate with a Base Rebate plus Additive Services construct. We provided a specific formula that calculates the appropriate compensation amounts, and explained how the formula can accommodate new data and changing priorities in an evolving energy landscape. In this final section, we gather some of the most valuable findings and recommendations noted throughout the preceding sections.

We recommend a compensation structure that uses TRC+ and RIM cost-effectiveness tests to screen for net benefits of a DER before clearing it for consideration for incentivization above the Base Rebate floor. For any DERs that clear the screening, we calculate a Net Distribution Value by subtracting NEM distribution compensation from Avoided Distribution Cost. For distributed generation resources, this provides the recommended Base Rebate value, which is adjusted if needed either up to the Base Rebate floor or down to avoid creating a cost shift to non-participants.

Evaluating this formula, we find that all solar use cases we examine fail the RIM cost-effectiveness screening, and that some show net costs in the TRC+ test as well. We also find that the NEM compensation for rooftop solar paid out through avoidance of onsite usage outweighs the distribution value that rooftop solar provides to the grid. Accordingly, we recommend the Base Rebate value for rooftop and community solar stay at the Base Rebate floor of $300/kW or $250/kW.

Energy storage, on the other hand, passes the TRC+ and RIM tests when responding to a real-time supply price signal included for use case evaluation. This indicates that, when provided a dispatch signal aligned with system and local needs, standalone storage can provide meaningful system value. For these resources, the Net Distribution Value provides an expectation for value provided, but we recommend compensating these resources through a performance-based Additive Services incentive. The amount of the incentive would be based purely on annual avoided distribution cost levelized over a 25-year period and paid out based on average kW output of the resource during call periods across each year.

Based on this mechanism, the recommended Additive Service incentive values are $25 and $32 per average kW for ComEd and Ameren respectively. These would be paid out each year based on DER dispatch during calls, so the DER lifetime total incentive amounts may exceed the range of the solar base rebates if it responds adequately to dispatch calls. This performance-based mechanism protects against overpayment, provides a way to align dispatch with the needs of the distribution system, and promotes “learning by doing” in advance of future DER dispatch that is increasingly focused on temporally and spatially specific grid needs.

For this first version of the compensation mechanisms, we do not recommend explicit inclusion of any additional non-monetized benefits in the Additive Services incentive. The reasoning for this recommendation falls into a few categories:

- Some benefits already accrue to DER host customers and therefore do not require additional compensation
- Some benefits cannot be quantified with sufficient certainty or cannot be proven to be much larger than zero using current data to provide a basis for compensation.
- A potential environmental justice benefit cannot be assessed without clarification from the state and stakeholders on goals for EJ residents and prioritization of these goals relative to tradeoffs.

However, we expect these potential benefits to be revisited in future versions of the compensation mechanism. Improved data and more spatially distinct DER valuation and compensation should allow for more certain quantification and realization of benefits, which in turn allows for inclusion of the benefits in Additive Services compensation.

The value of future data improvements is not limited to non-monetized benefits; the most critical data improvements pertain to distribution system valuation. Spatially differentiated and anticipatory distribution investment costs could unlock new levels of DER value to the grid that are unattainable in today's distribution planning paradigm. In a grid with Additive Services dispatch signals that vary by location and data to properly inform those signals at a feeder- or circuit-level, we expect the value of DER dispatch to vary widely, from values near zero to values that may be one or two orders of magnitude larger than the systemwide averages of today. Illinois should not expect to identify and compensate on this scale today, but should follow a “walk, jog, run” process that allows distribution planning and DER compensation to evolve in steps as processes are established and data becomes available.

Finally, we recognize key dependencies of this DER compensation mechanism on external context. The Illinois Power Agency’s annual refresh of the Adjustable Block Program solar rebates impacts the cost-effectiveness screening employed by our proposed compensation formula. Widespread changes to rate design, especially in the residential class, could have important consequences if new rates alter the distribution rate collection. Also the guidance provided to the utilities through orders in the Grid Plan proceedings may force updates to the utility-calculated bottom-up distribution avoided costs that form the basis of near-term distribution value used for this study.

Appendix A. Stakeholder Feedback

Table 21. Process feedback

Commenter	Summary of Comment	Status	How E3 Addressed the Comment
	Request to add a stakeholder meeting		E3, Viridis, and ICC added a fourth stakeholder workshop
	Request that the draft model be released earlier than scheduled to allow for more time to review and provide feedback		E3 released the initial draft model on October 31st to requesting parties and posted to the project website on November 7th. Subsequent drafts have been updated to include additional functionality as requested by stakeholders

Table 22. Compensation framework feedback

Commenter	Summary of Comment	Status	How E3 Addressed the Comment
Ameren	Recommends further discussion of whether additive services should be compensated above the base rebate; recommends it should be applied when DER provides specific locational and performance benefits		E3 is continuing its evaluation of the compensation framework
Vote Solar and Environmental Law & Policy Center	Ensure clear differentiation between system-wide and additive services		E3 to present clearer distinction today, but still expected to be a topic for further discussion

Table 23. Avoided cost feedback

Commenter	Summary of Comment	Status	How E3 Addressed the Comment
JSP	Why use the 95% Decarbonization Scenario in NREL Cambium for the energy/GHG avoided costs?		The 95% Decarbonization Scenario is the NREL Cambium scenario that aligns most closely with IL's decarbonization goals to reach net-zero by 2050 and in regards to emissions reductions and future resource mix.
JSP	Cambium gas prices are low because they are based on Henry Hub rather than Chicago city gate prices and don't capture Local Distribution Company (LDC) transportation costs		The NREL Cambium data provides the best available data. While the data might not be IL specific, E3 benchmarked Cambium energy prices with MISO historical energy prices for Illinois Hub and found them aligned.
JSP	There is no scarcity adjustment in Cambium		Although Cambium didn't perform scarcity adjustment, Cambium prices are higher than MISO historical prices during most scarcity hours.
JSP	Annual capacity prices are not adjusted to reflect PRM		E3 has adjusted annual capacity prices to reflect PRM.
JSP	PCAFs are not weighted appropriately across the hours		E3 has updated the model PCAF weighting
Ameren	The average cost approach to determining capacity costs is not reflective of the marginal impacts and includes system costs that cannot be deferred or reduced. Ameren supports the year-to-year stability of the average cost method and separating the non-Dx related avoided costs		E3 acknowledges that the methodology for calculating the distribution capacity costs is imperfect, but intends to stick with its proposed methodology absent better data
Ameren	It is unclear whether and how Tx avoided marginal costs are intended to be utilized		E3 has responded to Ameren to provide additional clarity – Tx avoided costs are used in the overall benefit cost evaluation
Vote Solar and Environmental Law & Policy Center	Study should rely on Marginal Cost Studies from Grid Plans		E3 expects that new/improved data will be incorporated into calculation of incentives as it becomes available

Table 24. Non-monetized benefit feedback

Commenter	Summary of Comment	Status	How E3 Addressed the Comment
JSP	In the resiliency calculations, the cost of the diesel generator should be higher to cover the costs of installation, permitting, etc.	●	The value that includes auxiliary costs reflects willingness to pay for *firm* capacity. We derate this by including only the partial capacity and energy value the DER would provide compared to firm backup
JSP	Resiliency $/kW may be too low because E3 assumes a large diesel generator which reflects economy of scale	●	We did not find a major difference in $/kW costs for smaller backup generators
JSP	6% customer preference (refers to the share of customers that tend to install backup generation) should be much higher as this does not reflect public benefits to society	●	Value increased for the commercial customer segment to 75%. But generally, even for a proxy value, we want to represent that only a fraction of customers implicitly value resiliency as high as the cost of a backup generator
JSP	Resilience benefit could be considered societal if power is shared across customers during dark sky event	●	This benefit is included as a PCT and TRC+ benefit. However, it would not appear in a RIM test since it does not impact the revenue requirement
JSP	Avoided fuel price risks should be material because renewable generation reduces dependence on fossil fuels	○	E3 agrees that avoided fuel price risk is material, but mechanism through which this is monetized for ratepayers is unclear
Ameren	Ameren's has prepared a report that shows that a DER's ability to provide reliability benefits is extremely limited	●	These considerations are expressed in this report and reliability value is not recommended for compensation
Ameren	Recommend further discussion on the appropriate level of support and incentive mechanism to encourage DERs in EJ communities	○	Extra considerations for EJCs still under consideration. Important to ensure that benefits accrue to EJ community members and not outside entities

Table 25. Benefit cost analysis feedback

Commenter	Summary of Comment	Status	How E3 Addressed the Comment
JSP	Why does storage have a $100/kW-yr O&M costs? Residential storage systems may have near-zero O&M cost		E3 now presents residential storage O&M as a range. Note that storage degradation is not broken out, but would reduce benefits or increase costs to offset and thus contribute to O&M expense
JSP	Suggested that Transmission escalation rates be aligned with PJM long-term transmission costs		Rate escalation updated to better align with available utility data and avoided energy supply cost escalation.
JSP	Suggested using a 1% escalation rate to align with ABP		See above escalation factor adjustment. E3 has discussed alignment of assumptions with Illinois Power Agency, who have indicated that some ABP assumptions are up for revision. Future alignment between these sources is recommended.
JSP	Suggested incorporating TOU or real-time rates for storage to be dispatched since IL legislation requires storage to be enrolled in TOU rates to receive rebates		Updated model functionality to allow for use of real-time pricing. Note that standalone storage results reflect perfect response to these rates (ideal scenario)
Ameren	The current methodology double counts the value of solar+storage by not accounting for self-consumption		This is a valid concern, but methodology in its current state does account for self-consumption

Appendix B. Avoided Cost Methodology

As detailed in Section 3, one common approach of calculating avoided costs is to isolate each component of the utility's revenue requirement that would be impacted by load increase or decrease and to quantify these components. The avoided costs, in $/kWh, developed in this study represent hourly, system-level costs of providing electric services for 25 years. Avoided costs of energy are "naturally" hourly values as they represent the costs of providing one additional unit of energy in each hour given the supply and demand balance, while avoided costs related to capacity are first calculated as annual values and then allocated to hourly values. The detailed methodology of hourly allocation can be found in Appendix C. This section describes additional details of data gathering and calculation steps related to certain avoided cost components.

8.1.1 Distribution Capacity Avoided Costs

Near-Term Distribution Value

Near-Term distribution avoided costs come directly from each utility's most recent distribution cost of service studies. These values are calculated based on bottom-up assessments of forecasted distribution system needs at individual facilities (primarily feeders and circuits) within each utility's service territory. The unit costs of capacity to meet these needs is then averaged across the utility's entire service territory to estimate the average marginal capacity value that DERs installed at any given location within the utility's territory could potentially provide. The resulting values have been presented within the refiled grid plans but not yet approved at the time of this analysis. Both the near-term and long-term distribution values are then allocated across hours of the year following a PCAF approach.

Long-Term Distribution Value

Long-term distribution avoided cost value is calculated using data from each utility's FERC Form 1 filings and refiled grid plan. To calculate a total dollar-per-kilowatt average value, the End of Year Distribution Station Equipment category from FERC Form 1 is divided by the system peak load described in the refiled grid plan for each year of the 10-year period from 2014-2023. These values are converted to 2024$ using the Handy-Whitman index for utility cost escalation and then an average value is taken across the period. These values are all publicly available and are displayed for Ameren and ComEd in Figure 38 and Figure 39.

Figure 38. Ameren Long-Term Distribution Avoided Cost $ / kW Calculation

Ameren FERC and RGP data							
	Station Equipment	*Station Equipment*	*Ameren RGP*				
Year	Beginning of Year	End of Year	Peak Load (MW)	Load (kW)	EOY Station Equip / Peak Load	Handy Whitman	EOY Station Equip / Peak Load
Units	*$*	*$*	*MW*	*kW*	*$ / kW*	Index to 2024$	2024$ / kW
2012	$726,007,448	$771,084,895				*1.645*	*$0*
2013	$771,084,895	$832,599,912				*1.625*	*$0*
2014	$832,599,912	$898,311,841	7271	*7271000*	*$123.55*	*1.579*	*$195*
2015	$898,311,841	$1,006,607,888	6972	*6972000*	*$144.38*	*1.516*	*$219*
2016	$1,006,607,888	$1,105,627,848	7138	*7138000*	*$154.89*	*1.486*	*$230*
2017	$1,105,627,848	$1,183,886,723	7145	*7145000*	*$165.69*	*1.492*	*$247*
2018	$1,183,886,723	$1,237,056,758	7052	*7052000*	*$175.42*	*1.424*	*$250*
2019	$1,237,056,758	$1,292,294,304	7032	*7032000*	*$183.77*	*1.396*	*$257*
2020	$1,292,294,304	$1,350,242,400	6644	*6644000*	*$203.23*	*1.362*	*$277*
2021	$1,350,242,400	$1,427,033,377	6734	*6734000*	*$211.91*	*1.232*	*$261*
2022	$1,427,033,377	$1,480,761,656	6764	*6764000*	*$218.92*	*1.113*	*$244*
2023	$1,480,761,656	$1,546,759,354	7036	*7036000*	*$219.84*	*1.045*	*$230*
Source:	*Ameren FERC Form 1 data*		*Refiled Grid Plan*			Average (2014-2023):	*$240.92*

Figure 39. ComEd Long-Term Distribution Avoided Cost $ / kW Calculation

ComEd FERC and RGP data							
	Station Equipment	*Station Equipment*	*ComEd RGP*				
Year	*Beginning of Year*	*End of Year*	Peak Load (MW)	Load (kW)	EOY Station Equip / Peak Load	Handy Whitman	EOY Station Equip / Peak Load
Units	*$*	*$*	*MW*	*kW*	*$ / kW*	Index to 2024$	2024$ / kW
2012	$2,254,921,532	$2,319,149,249	23600.91	*23600910*	*$98.27*	*1.645*	*$162*
2013	$2,319,149,249	$2,407,279,550	22269.02	*22269020*	*$108.10*	*1.625*	*$176*
2014	$2,407,279,550	$2,524,644,462	19721.23	*19721230*	*$128.02*	*1.579*	*$202*
2015	$2,524,644,462	$2,603,047,154	20162.3	*20162300*	*$129.10*	*1.516*	*$196*
2016	$2,603,047,154	$2,800,468,721	21174.58	*21174580*	*$132.26*	*1.486*	*$197*
2017	$2,800,468,721	$2,968,843,776	20350.87	*20350870*	*$145.88*	*1.492*	*$218*
2018	$2,968,843,776	$3,173,741,521	21349.37	*21349370*	*$148.66*	*1.424*	*$212*
2019	$3,173,741,521	$3,394,469,433	20948.74	*20948740*	*$162.04*	*1.396*	*$226*
2020	$3,394,469,433	$3,526,192,365	20220.04	*20220040*	*$174.39*	*1.362*	*$238*
2021	$3,526,192,365	$3,726,034,749	21166.21	*21166210*	*$176.04*	*1.232*	*$217*
2022	$3,726,034,749	$3,891,202,891	21262.33	*21262330*	*$183.01*	*1.113*	*$204*
2023	$3,891,202,891	$4,066,720,575	22467.01	*22467010*	*$181.01*	*1.045*	*$189*
Source:	*ComEd FERC Form 1 data*		*Refiled Grid Plan*			Average (2014-2023):	*$209.74*

The resulting $/kW values are then annualized incorporating values filed by each utility in workpapers for their distribution cost of service studies, as part of the refiled grid plan. The steps and inputs for these calculations are shown in Figure 40 and Figure 41. Though ComEd did not explicitly adjust for losses in their initial cost of service study, this long-term distribution value calculation does apply a distribution loss factor provided by ComEd to arrive at a final $/kW-year value. This step is consistent with the loss factor adjustment applied to achieve Ameren's distribution marginal cost value. Because loss adjustments are applied to distribution capacity value at this step in the process, they are not re-applied again in the conversion to a final $/kWh value like in the case of the transmission and generation capacity avoided costs.

Figure 40. Ameren Long-Term Distribution Avoided Cost Annualization

Annualization values from Ameren DCOS Study and filed workpapers

No.	Description	Input Factors	Calculation	Reference
1	*Average* Investment per kW of added load carrying capability		$240.92	Average Distribution Capacity Investment
2	Add: General Plant Loading	9.58%	263.99	Line 1 x (1 + 9.58%)
3	Real Economic Carrying Charge (RECC)	7.14%	7.14%	
4	Add: A&G Loading (Plant-related)	0.15%	0.15%	
5	Total Annual Carrying Charge		7.30%	Line 3 + Line 4
6	Annualized Investment ($ / kW-year)		$ 19.26	Line 2 x Line 5
7	Add: O&M Expenses	3.55%	8.54	Line 1 x (3.55%)
8	Add: A&G Loading (O&M-related)	26.00%	2.22	Line 7 x (26.00%)
9	Subtotal (Annualized Investment + O&M)		$ 30.02	Line 6 + Line 7 + Line 8
10	Working Capital			
11	Add: Materials and Supplies	0.72%	$ 1.91	Line 2 x 0.72%
12	Add: Prepayments	0.47%	1.25	Line 2 x 0.47%
13	Add: Cash Working Capital	7.99%	0.86	Line 7 + Line 8 x 7.99%
14	Total Working Capital		$ 4.01	Line 11 + Line 12 + Line 13
15	Working Capital-related Revenue Requirements	8.29%	0.33	Line 14 x 8.29%
16	Loss Factor	13.00%	13.00%	Company Loss Factors
17	**Capacity-related Annualized Marginal Cost ($ / kW-year)**		$ 34.30	(Line 9 + Line 15) x (1+ 13.0%)*

**Calculation for applying distribution loss factors is consistent with Ameren's approach in their DCOS study and workpapers*

Figure 41. ComEd Long-Term Distribution Avoided Cost Annualization

Annualization values from ComEd DCOS Study and filed workpapers

No.	Description	Input Factors	Calculat	Reference
1	*Average* Investment per kW of added load carrying capability		$209.74	Average Distribution Capacity Investment
2	Economic Carrying Charge	8.36%	8.36%	
3	General Plant Loader	9.59%	9.59%	
4	Plant-related A&G Loader	0.03%	0.03%	
5	Annualized per-kW Marginal Cost Subtotal		$19.29	Line 1 * (1 + Line 3)*(Line 2 + Line 4)
6	Annual Fixed O&M per kW Expenses		$6.41	*Using 2019-2022 average Marginal O&M $/kW-yr from DCOS*
7	Non-plant related A&G Loading (1+loader)		1.051	
8	Material, Supplies and Prepayments	0.0003647	$0.0765	Line 1 * [0.0003647]
9	Cash Working Capital Allowance	0.0106000	$0.0715	Line 6 * Line 7 * [0.0106]
10	Annualized MC per kW of Peak Load ($/kW-yr)		$26.18	Line 5 + (Line 6 * Line 7) + Line 8 + Line 9
11	Loss Adjustment		6.89%	*ComEd average distribution losses from 2021 loss study, adjusted upward by 1.5x to estimate marginal losses*
12	**Capacity-related Annualized Marginal Cost ($ / kW-year)**		$27.98	Line 10 * (1+ Line 11)*

**Calculation for applying distribution loss factors is consistent with Ameren's approach in their DCOS study and workpapers*

8.1.2 Use of Cambium Data

Cambium 2023 data[38] developed by NREL is the major source for the resource generation related avoided costs. Cambium has three main scenarios:

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[38] Full data set is available at https://scenarioviewer.nrel.gov/?project=0f92fe57-3365-428a-8fe8-0afc326b3b43&mode=download&layout=Default. We used both annual and hourly values for avoided cost development.

1. **Mid case**: projects electric sector policies as existed in September 2023 and doesn't include nascent technologies such as carbon capture, hydrogen combustion turbines and small nuclear reactors.
2. **95% decarbonization by 2050**: assumes National electricity sector decarb constraint that linearly declines to 5% of 2005 emissions on net by 2050. This scenario includes nascent technologies.
3. **100% decarbonization by 2035**: assumes national electricity sector decarb constraint that linearly declines to zero of 2005 emissions on net by 2035. This scenario includes nascent technologies.

After benchmarking with MISO's LRTP, we chose the 95% decarbonization by 2050 scenario. Detailed benchmarking results can be found in Section 3.3.

The specific Cambium data used for each avoided cost component are listed as the following:

- **Energy avoided costs**: energy_cost_busbar (i.e., marginal costs of energy at busbar)
- **Annual capacity avoided costs**: capacity_shadow_price (i.e., shadow price on the capacity constraint) grossed up by prm (i.e., Planning Reserve Margin)
- **Transmission and distribution line losses**: distloss_rate_average (i.e., average distribution loss rate), disloss_rate_marg (i.e., marginal distribution loss rate) and trans_losses (i.e., average transmission loss rate)

Appendix C. Hourly Allocation

To recognize the importance of DERs providing value during the specific hours when system capacity is constrained, E3 allocated the total distribution, transmission, and generation capacity value across the hours of the year with the greatest anticipated load. The approach used may be generally categorized under a Peak Capacity Allocation Factor (PCAF) methodology.

Hourly system load forecasts for Ameren and ComEd were obtained from the Cambium MISO Central and PJM West datasets, respectively, for the years 2025-2050.[39] Allocation factors for transmission and distribution capacity were then assigned to the top 150 load hours based on the share of load in each of these hours divided by the total load across these 150 top load hours.[40] The determination of generation capacity allocation factors follows the same process but using the top 100 hours of net load.[41] Figure 42 displays this calculation as applied to each hour of the year.

Figure 42. PCAF Equation

$$\text{PCAF}\,[a,h] = \frac{(\text{Load}[a,h] - \text{Threshold}[a])}{\text{Sum of all positive values for } (\text{Load}[a,h] - \text{Threshold}[a])}$$

Where:

- a is the applicable utility service territory area
- h is hour of the year
- Load is the net system load (applied to both distribution and transmission in this instance)
- Threshold: The 150th largest load value

The sum of the resulting allocation factors for all top hours is equal to 1, while all other hours of the year were assigned allocation factors of zero. The total avoided cost of capacity for each component was multiplied by the allocation for each hour of the year to produce a $/kWh value, such that the sum of all hourly values is equal again to the original $/kWh capacity cost.

Figure 43 illustrates how these allocation factors are distributed across the days and hours of the year for a single historical year. In early years, the system peak and resulting allocation factors are concentrated in summer months, so that is when additional capacity is most valuable. As load patterns change over time, including due to heating and vehicle electrification, the allocation factors shift in kind. In order to provide a clearer picture of the intraday hourly patterns, Figure 44 displays the sum of all allocation factors assigned to each hour of the day when combined across all days of

[39] Transmission and distribution allocation factors are based on the total end-use load minus distributed solar data, while generation capacity allocation factors are based on the total end-use load minus all renewable generation.

[40] For years when multiple hours are ‘tied’ at the threshold for the 150th peak hour, all of these threshold hours are included within the set of peak hours.

[41] The use of only 100 hours for generation capacity is intended to align with Cambium’s allocation of these costs

the year. In early years the capacity value is concentrated in the mid to late afternoon, though this also shifts with future load patterns.

Figure 43. Ameren Single Year Peak Capacity Allocation Factors

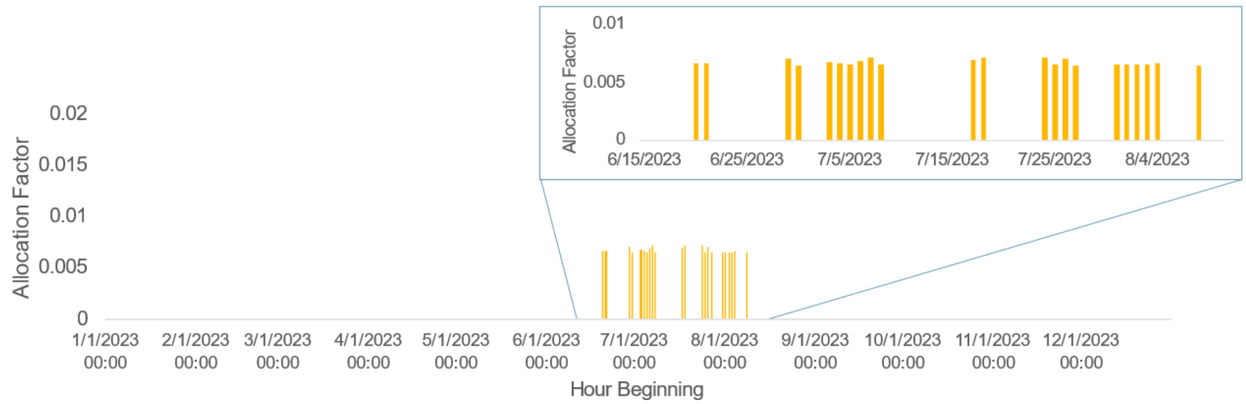
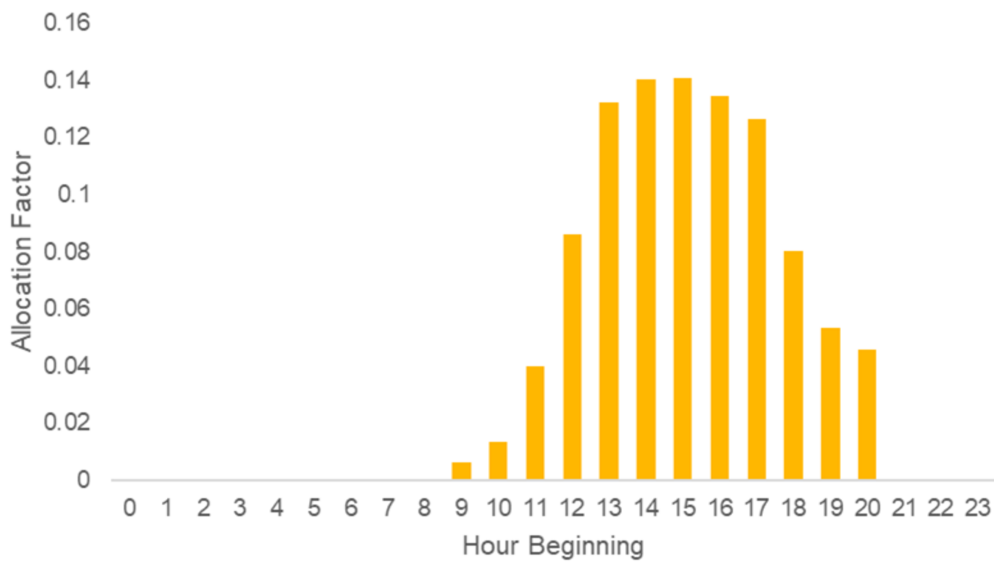


Figure 44. Ameren Transmission and Distribution Allocation Factors by Hour of Day



Within the BCA tool, the expected load or generation profiles of individual DERs are multiplied by the hourly $/kWh avoided costs to estimate the value provided by the given DER. As a result, any resource able to provide capacity to the grid during all peak load hours of a year would then be determined to provide the full capacity benefit for that year. A resource able to supply capacity during a portion of the peak load hours would be estimated to provide some allocation-weighted portion of the maximum potential benefit to the electric grid.

Appendix D. Weather Re-mapping

As described in Section 3, calculating the total value of a DER involves multiplying its generation profiles by the corresponding hourly avoided costs. However, these two datasets come from different sources, each based on distinct underlying weather data: the distributed generation profile from NREL's SAM relies on 2018 weather, whereas the avoided costs from NREL's Cambium use 2012 weather. Because weather influences both electricity consumption and resource generation, and thus overall supply costs, misaligned weather data can yield inaccurate estimates of DER benefits. A mismatch may pair high DER generation with low avoided costs—or vice versa—distorting the true value of distributed resources.

To address the challenges of aligning weather data across different years, E3 has developed a flexible, standardized, and modular weather remapping tool. This tool employs a linear cost function based on daily temperature and date variables, generating a weighted sum of individual cost components for each combination of base and remap days. Using multiple integer linear programming with optimization constraints, the tool selects the optimal pairings of base and remap dates. The output is a set of mapped day pairings between the base year (destination weather year) and the remap year (the weather year of the raw data). This process leverages temperature metrics from both years to create the day map, followed by a conversion step that transforms data from the remap year to align with the base year.

We decided to adjust all timeseries data related to the avoided costs such that its underlying weather is 2018 rather than 2012. To perform weather re-mapping, we followed the steps below:

1. Identify the Weather Years: We decided to adjust all timeseries data related to avoided costs so that the underlying weather is 2018.
    a. Base (Destination) Year: 2018
    b. Remap (Source) Year: 2012
2. Collect Hourly Temperature Data: We gathered temperature data from National Oceanic and Atmospheric Administration (NOAA) for both 2012 and 2018 from the following weather stations as proxies for each utility service area:
    a. Ameren (MISO): Springfield – Abraham Lincoln Capital Airport (SPI)
    b. ComEd (PJM): Chicago – O'Hare International Airport (ORD)
3. Apply the Weather Remapping Tool: The tool reads the hourly temperature data from both years. It then "reshuffles" the days of the 2012 avoided-cost timeseries, using the optimization to match the 2018 temperature patterns as closely as possible.
4. Generate the Re-Mapped Timeseries: The output is a newly arranged (re-mapped) 2012 dataset, now aligned with 2018 temperature trends.

Figure 45 and Figure 46 illustrate average temperature between the three data sets:

- Unmapped (2012): The original 2012 weather year data
- Base (2018): The 2018 weather year data, used as the "destination"
- Remapped: The re-mapped dataset that preserves the structure of 2012 data but aligns it with 2018 weather conditions.

As shown in the figures, temperature data after remapping are more aligned with the base weather year.

Figure 45: Weather Remapping Results - Ameren (Hourly and Month-Hour Averages)

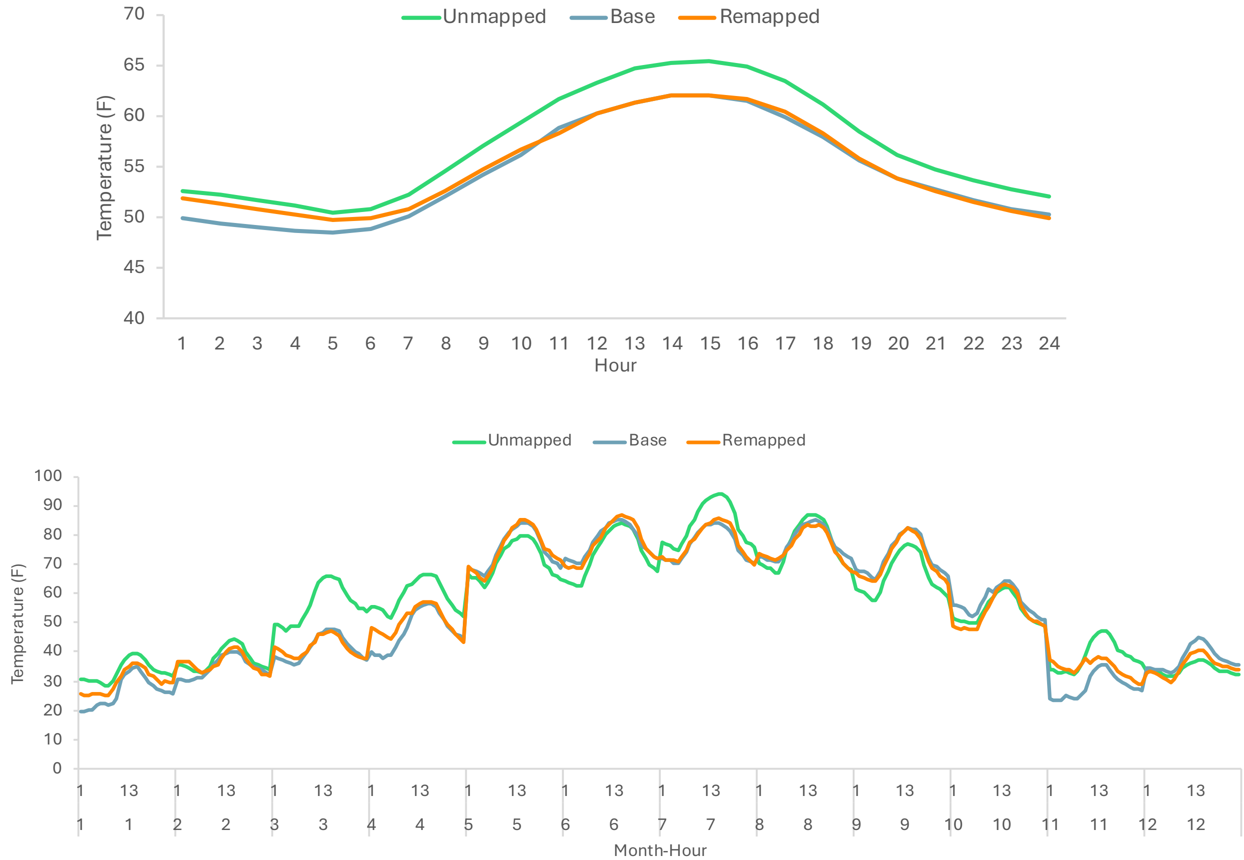
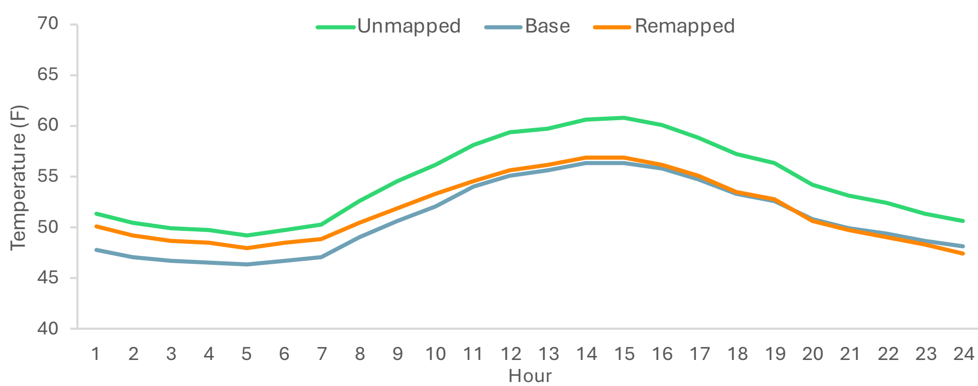
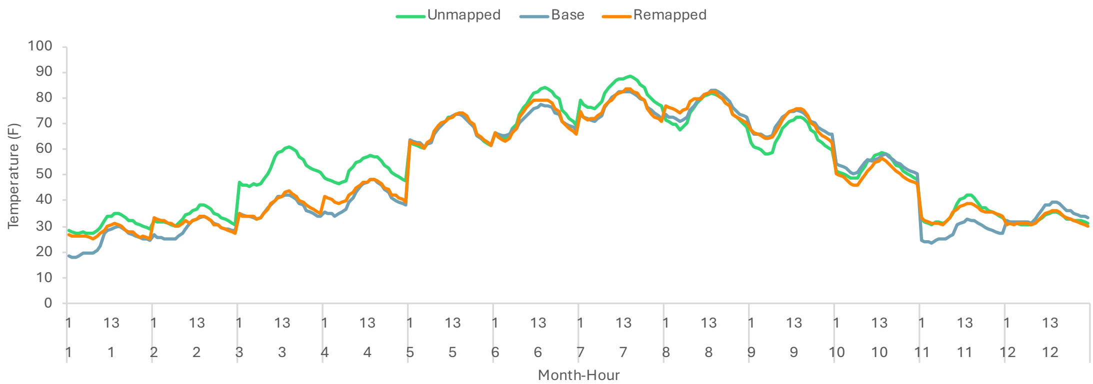


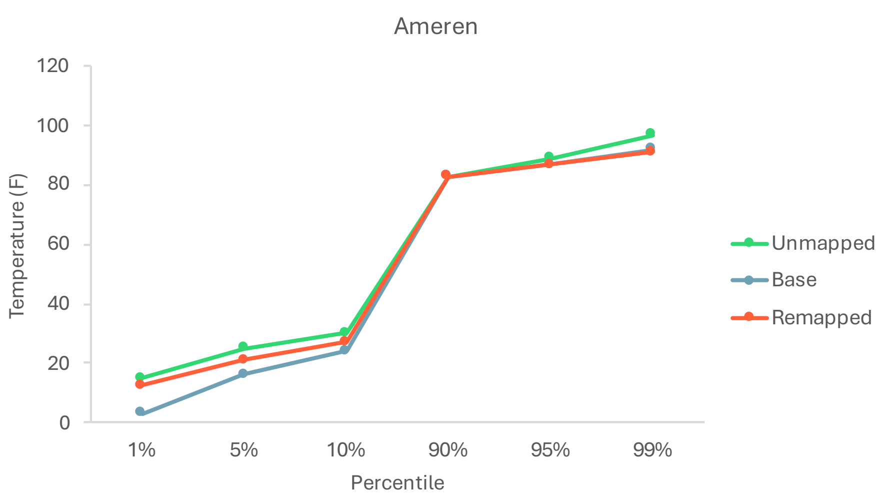
Figure 46: Weather Remapping Results - ComEd (Hourly and Month-Hour Averages)

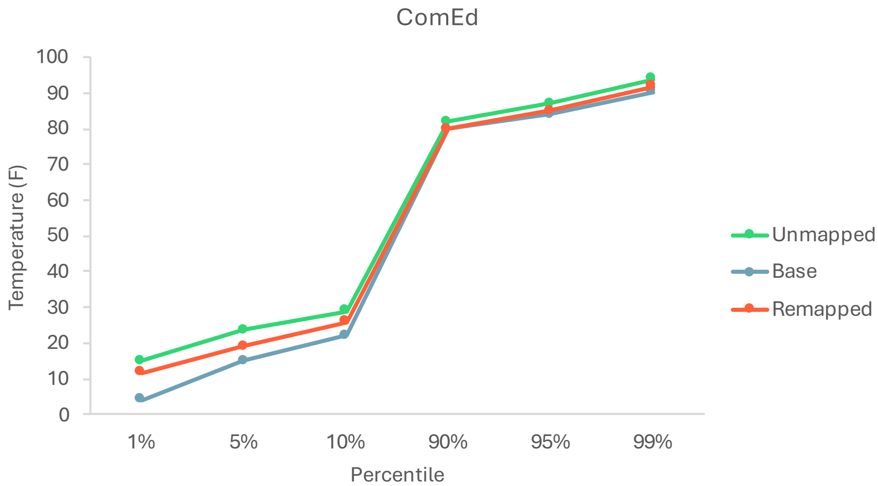




To evaluate the effectiveness of the weather remapping process, temperature statistics (1st, 5th, 10th, 90th, 95th, and 99th percentiles) were calculated for hourly temperature data across three datasets: 2018 original, 2012 original, and 2012 remapped. The remapping process demonstrates strong temporal alignment with the target year but is inherently limited in reproducing extremes that are absent in the original dataset, as the tool does not perform extrapolation. For instance, it lacks the ability to create colder days that were not part of the original data. However, the tool effectively moderates extreme highs to align better with the target year, as seen in the Ameren and ComEd cases, leveraging the availability of milder days in the dataset. This limitation is reasonable, as the tool reuses and adjusts existing data rather than generating new data.

Figure 47: Temperature Statistics – Percentile Charts for Ameren and ComEd




ComEd
Temperature (F)
100
90
80
70
60
50
40
30
20
10
0
1%
5%
10%
90%
95%
99%
Percentile
Unmapped
Base
Remapped

Appendix E. Detailed BCA methodology and Results

Table 26. Additional Assumptions and Data Sources

<table>
<tr><th>Input</th><th>Data Source</th><th>Notes</th></tr>
<tr><td>Capital Cost - Solar</td><td>NREL ATB 2024</td><td>Use overnight capital costs (OCC, $/kW) as the metric. For commercial solar, use Solar – PV Dist. Comm (assumed 200 kW). For residential solar, use Solar – PV Dist. Res (assumed 7.9 kW). Apply the moderate scenario and assume Class 3 (with a capacity factor of approximately 17%–18%). Interconnection costs are included in the OCC, as outlined in the NREL documentation. Costs are converted from 2022 real dollars to nominal dollars using the inflation rate assumed in the BCA tool.</td></tr>
<tr><td>Capital Cost - Storage</td><td>NREL ATB 2024</td><td>Use overnight capital costs (OCC, $/kW) as the metric. For commercial battery storage, use Commercial Battery Storage (assumed 1800 kW and is applicable for sizes within 100 – 2000 kW). For residential battery storage, use Residential Battery Storage (assumed 5 kW). Apply the moderate scenario. Interconnection costs are included in the OCC, as outlined in the NREL documentation. Costs are converted from 2022 real dollars to nominal dollars using the inflation rate assumed in the BCA tool.
To ensure consistency in model assumptions in BCA tool, we selected the cost forecast for the following duration for each configuration
Storage Duration Inputs<table><tr><th>Customer Type</th><th>Solar + Storage</th><th>Storage</th></tr><tr><td>Residential</td><td>2.5</td><td>4</td></tr><tr><td>Commercial</td><td>2</td><td>4</td></tr></table></td></tr>
<tr><td>Interconnection Cost</td><td>NREL ATB 2024</td><td>Interconnection costs are included in the OCC, as outlined in the NREL documentation.</td></tr>
<tr><td>O&M Cost - Solar</td><td>NREL ATB 2024</td><td>Same as Capital Cost – Solar but using Fixed O&M cost forecasts ($/kW-yr)</td></tr>
<tr><td>O&M Cost - Storage</td><td>NREL ATB 2024</td><td>Same as Capital Cost – Storage but using Fixed O&M cost forecasts ($/kW-yr)</td></tr>
<tr><td>ABP (Illinois Shines / Solar for All Incentive)</td><td>ABP REC Pricing Model</td><td>2024-2025 REC prices are used in the calculation of ABP incentive</td></tr>
<tr><td>Customer Rates</td><td>Ameren and ComEd</td><td>Rates DS-1, DS-2, and DS-3 are used for Ameren customers. BES-Residential Single Family, BES-Residential Multi Family, BES-Small Load, and BES-Medium Load are used for ComEd customers. Minimum, fixed, energy, transmission and distribution charges were gathered from utility websites.</td></tr>
<tr><td>Customer Load Data</td><td>ResStock and ComStock</td><td>Residential single family and multifamily load shapes for both LMI and non-LMI customers come from ResStock. Commercial load shapes for small and mid-size offices and primary and secondary schools come from ComStock.</td></tr>
<tr><td>Solar Generation Profiles</td><td>NREL SAM</td><td>Solar shapes are simulated using generic assumptions with a location in Chicago to represent ComEd customers and a location in Springfield to represent Ameren customers.</td></tr>
</table>

Application of Storage Dispatch Logic

Storage dispatch logic varies between the two distinct storage technologies modeled:

- **Hybrid storage (Solar+Storage)** is charged exclusively from excess solar generation. The battery cycles daily, charging when there is excess solar generation and dispatching to meet customer load in most expensive hours. In the case that there is no performance credit or TOU rates, storage will discharge arbitrarily to meet load. In the case that there is a price signal where exports are valued more than imports, storage will discharge completely to capture exported energy value.
- **Standalone storage** is charged from electricity provided by the grid, opting to charge when imported energy in the lowest price hour of the day is less expensive than imported energy in the most expensive hour multiplied by storage efficiency losses. In the case where all imported energy prices are the same, or that the difference in price is not sufficient to overcome storage losses the battery will not cycle. Storage dispatch is also set to perform demand charge arbitrage. This is applied such that the storage will dispatch a portion of its capacity to reduce loads that are greater than the 95th percentile of load for a given month to reduce potential demand charges.

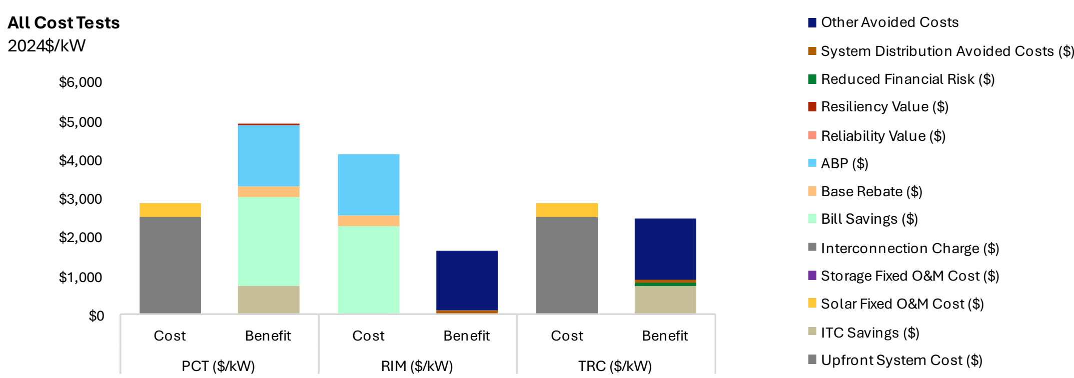
Benefit Cost Analysis Results for all cases

The following charts depict results of each cost test performed for all cases modeled for this study.

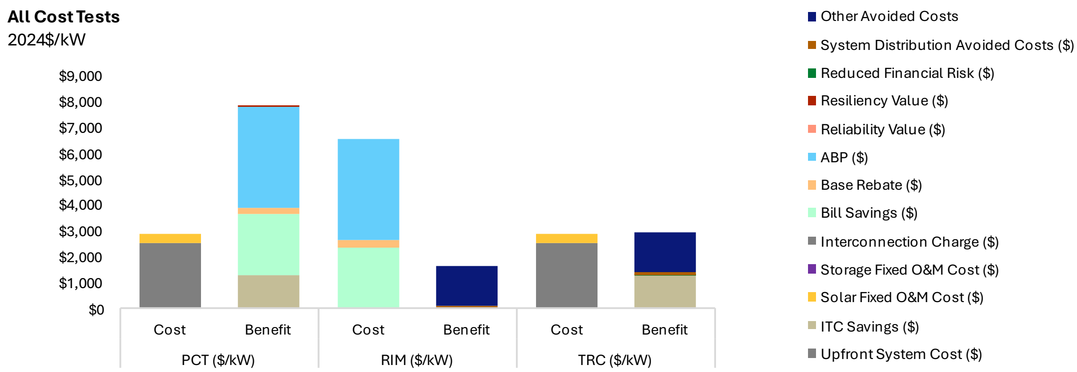
Ameren Residential Results

Single Family

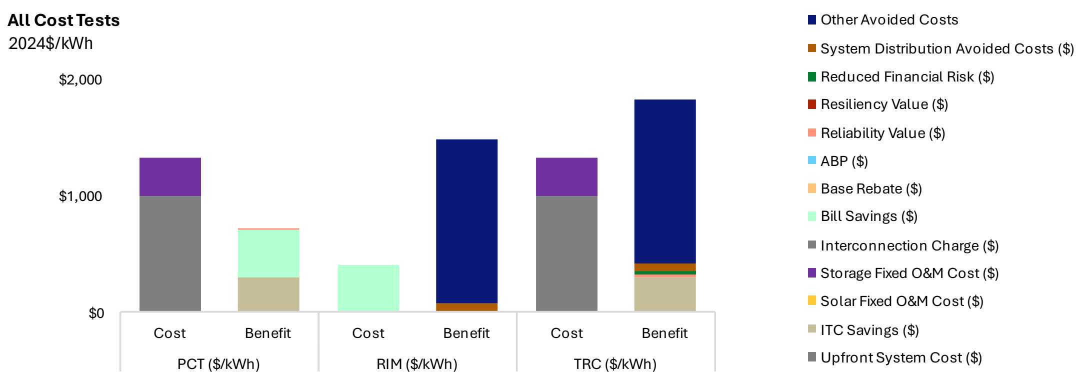
Solar – Non-LMI



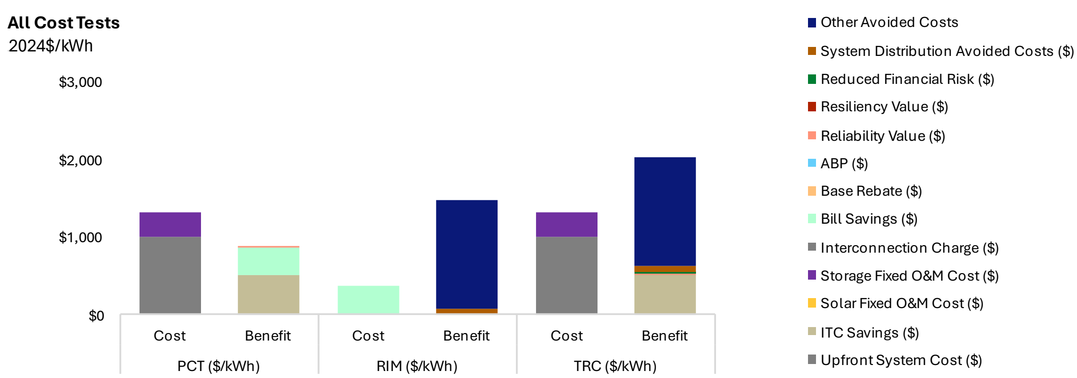
Solar – LMI



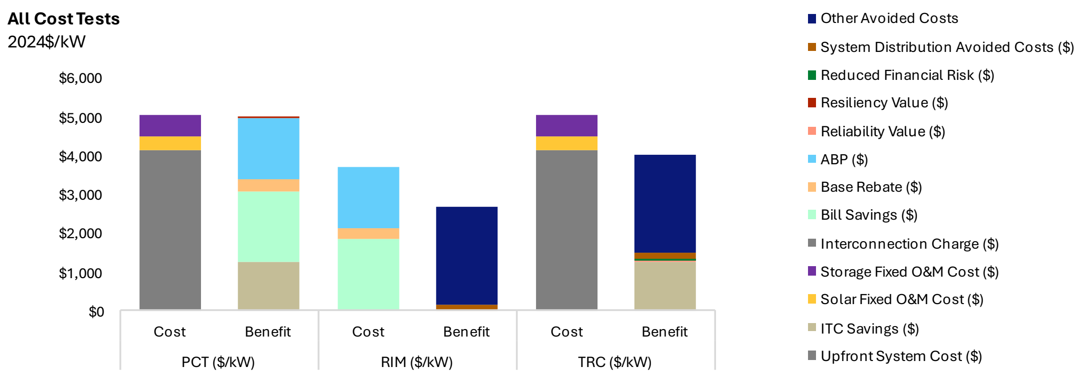
Storage – Non-LMI



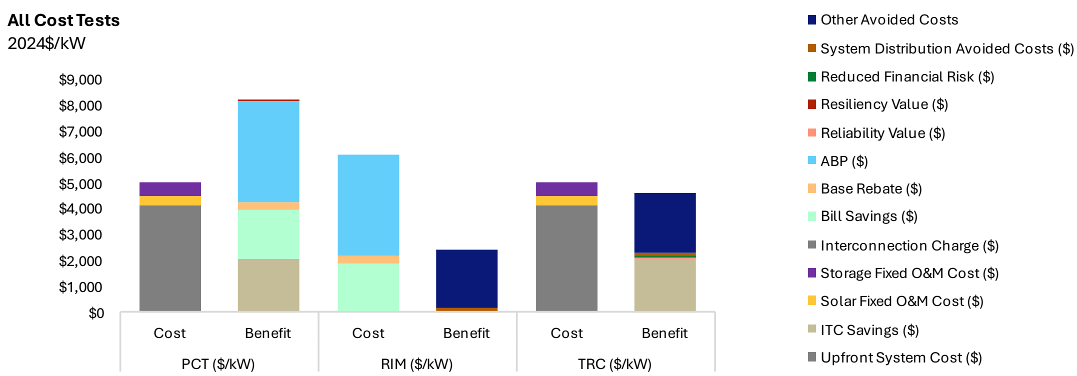
Storage – LMI



Solar + Storage – Non-LMI

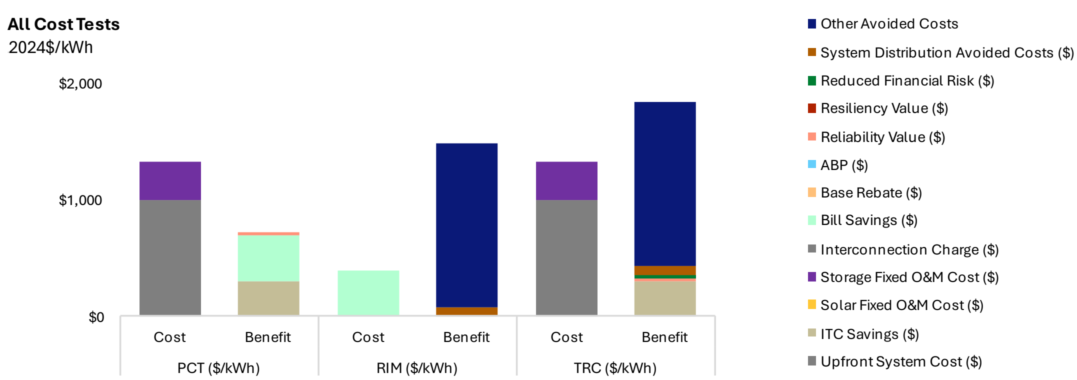


Solar + Storage – LMI

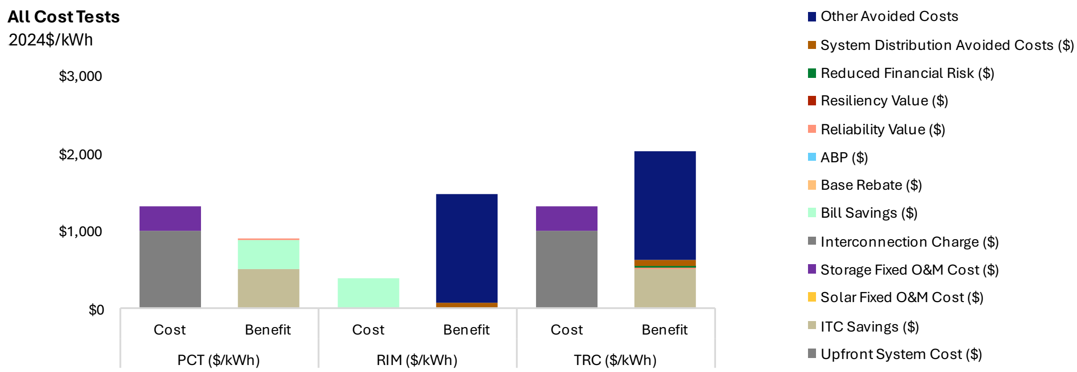


Multi-Family

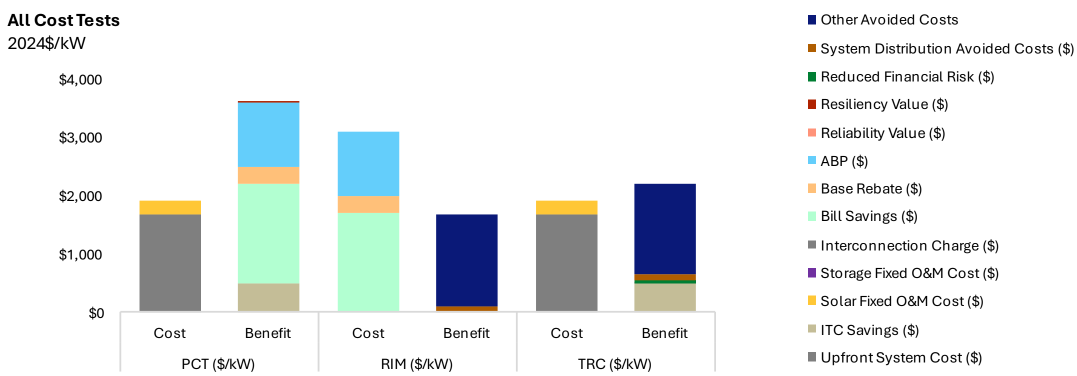
Storage – Non-LMI



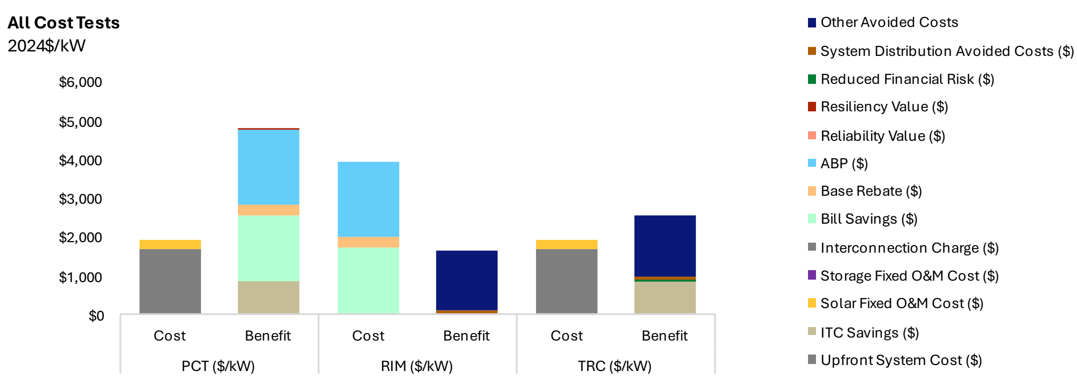
Storage – LMI



Community Solar – Non-LMI

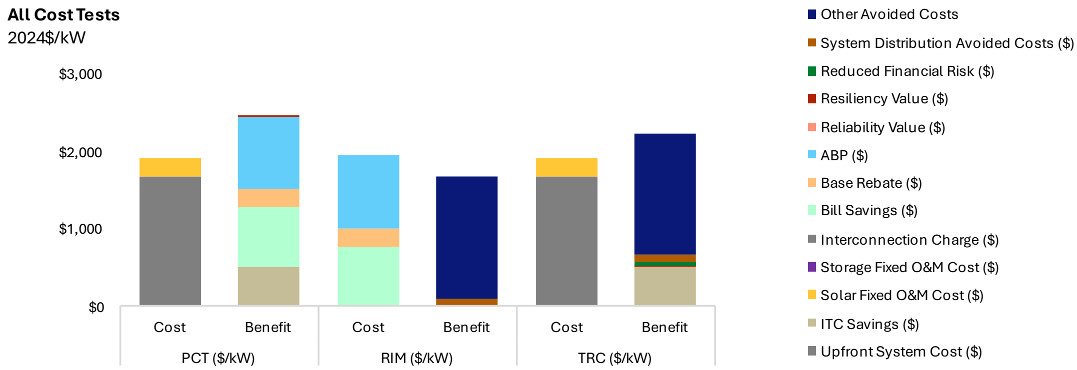


Community Solar – LMI

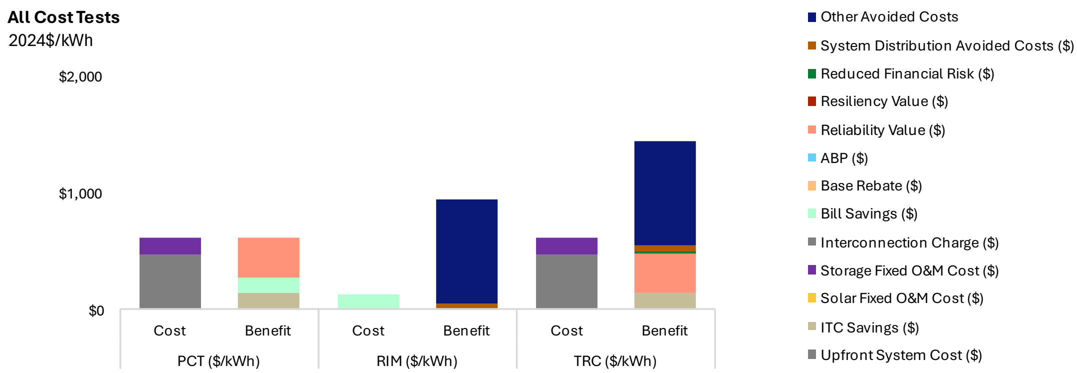


Commercial – Medium Office

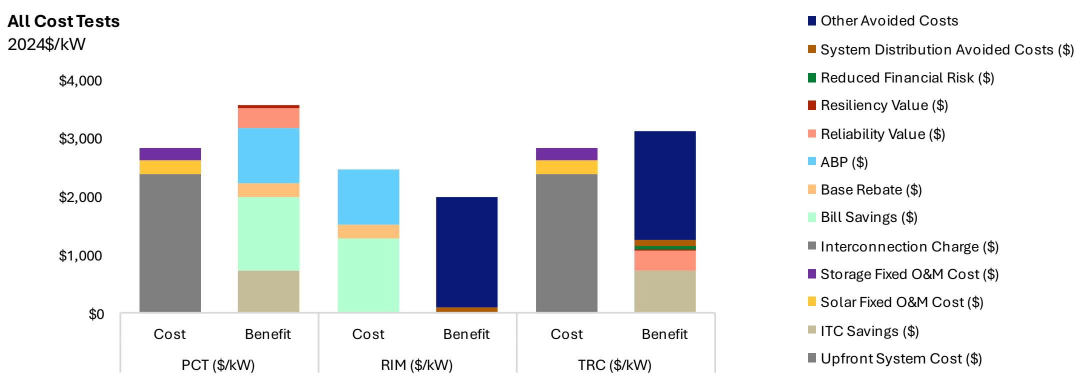
Solar



Storage

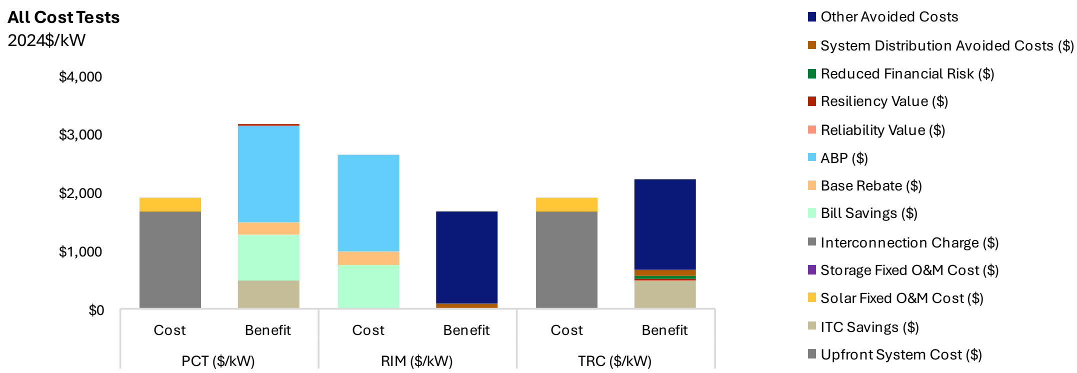


Solar + Storage

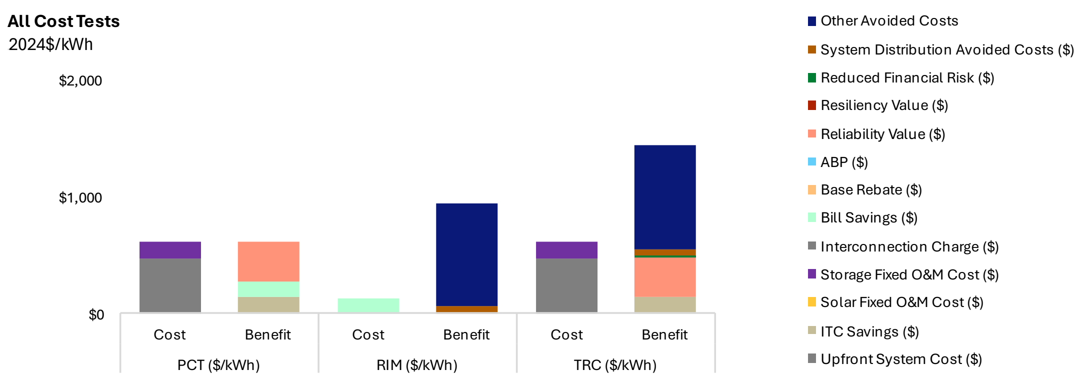


Commercial Primary School

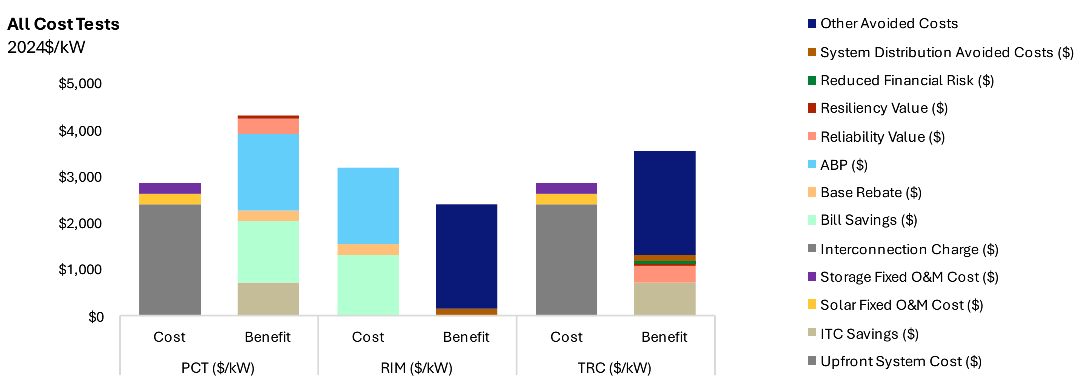
Solar



Storage



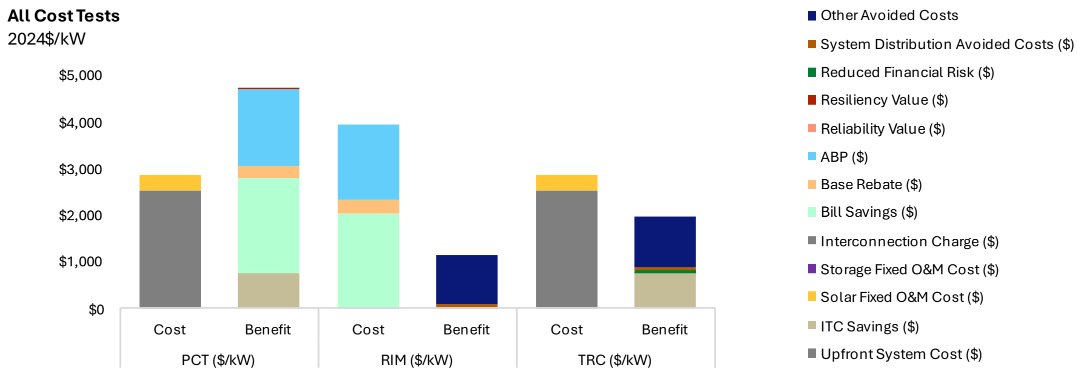
Solar + Storage



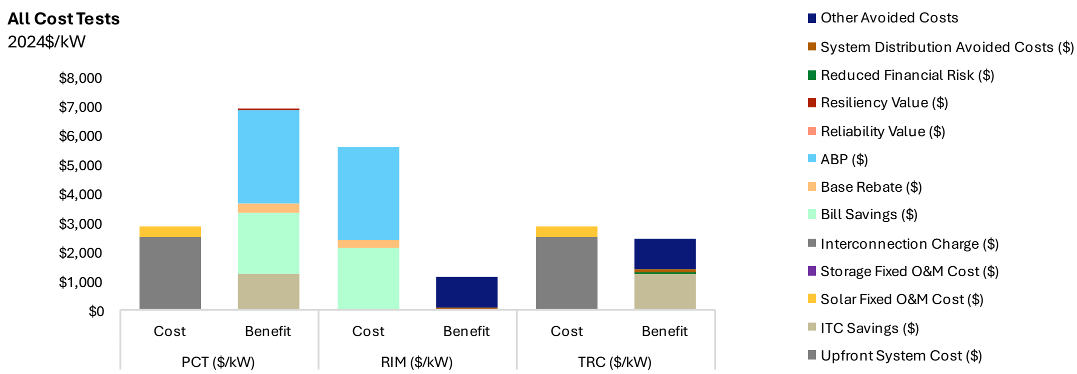
ComEd Residential Results

Single Family

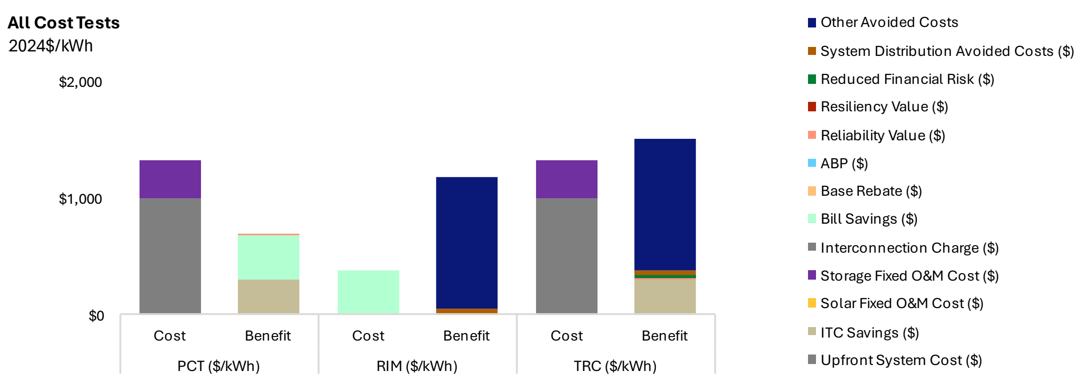
Solar – Non-LMI



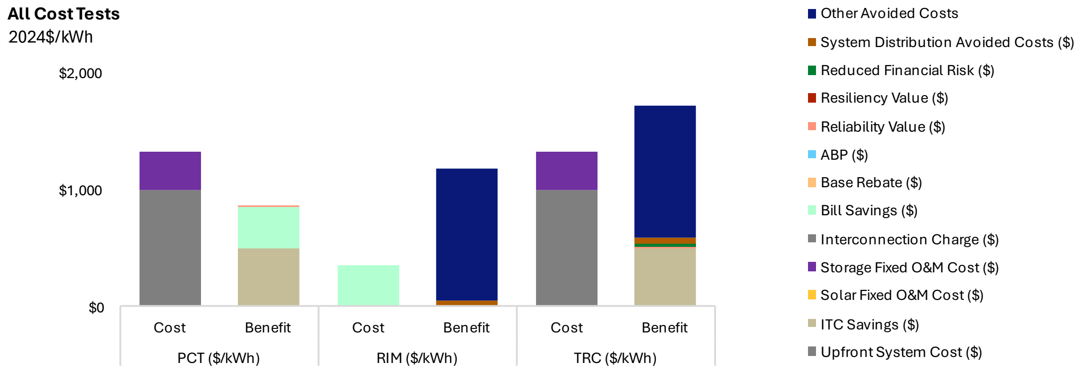
Solar – LMI



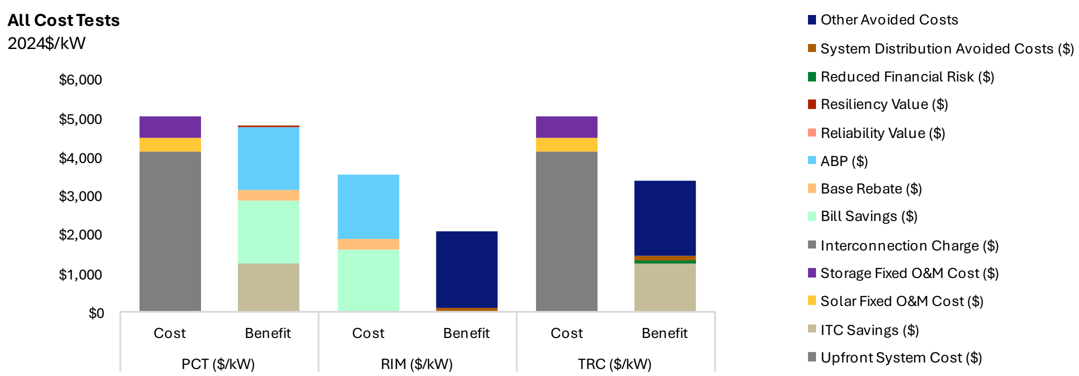
Storage – Non-LMI



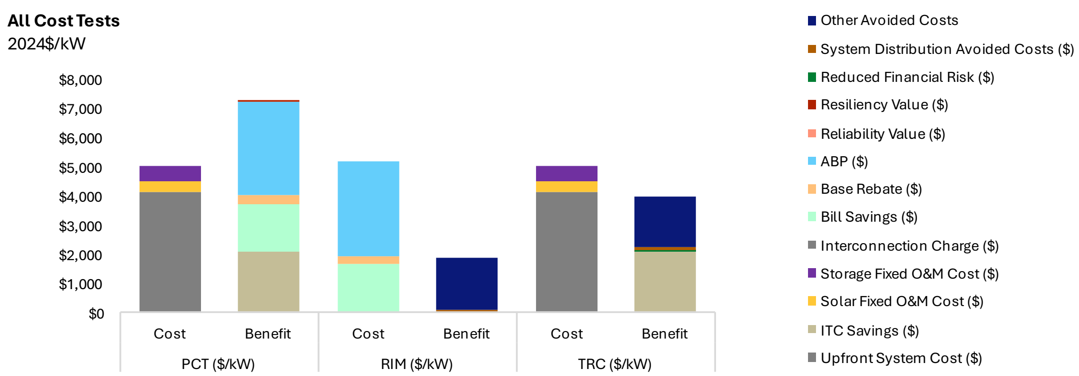
Storage – LMI



Solar + Storage – Non-LMI

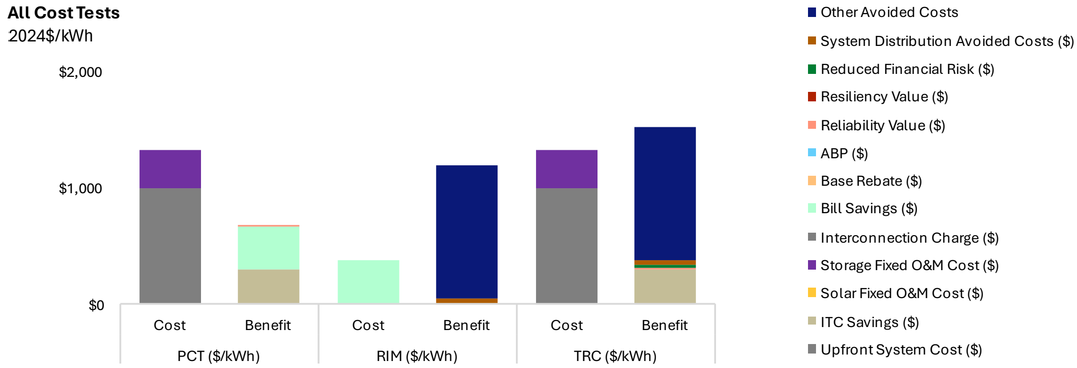


Solar + Storage – LMI

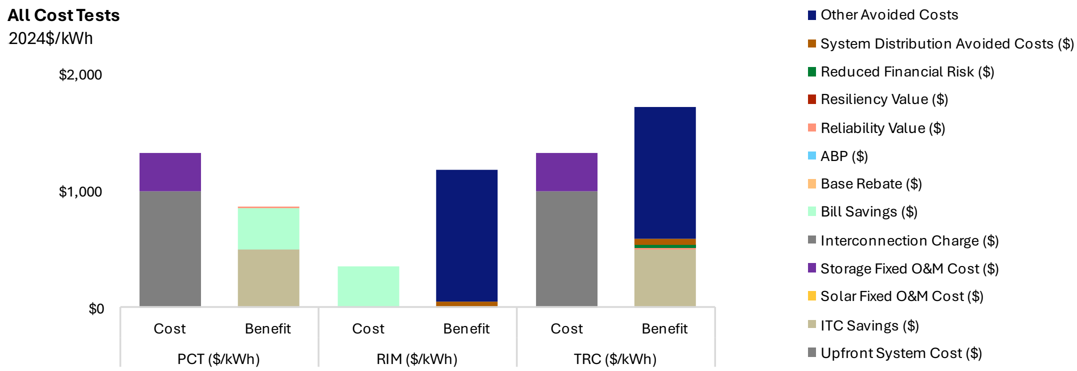


Multi-Family

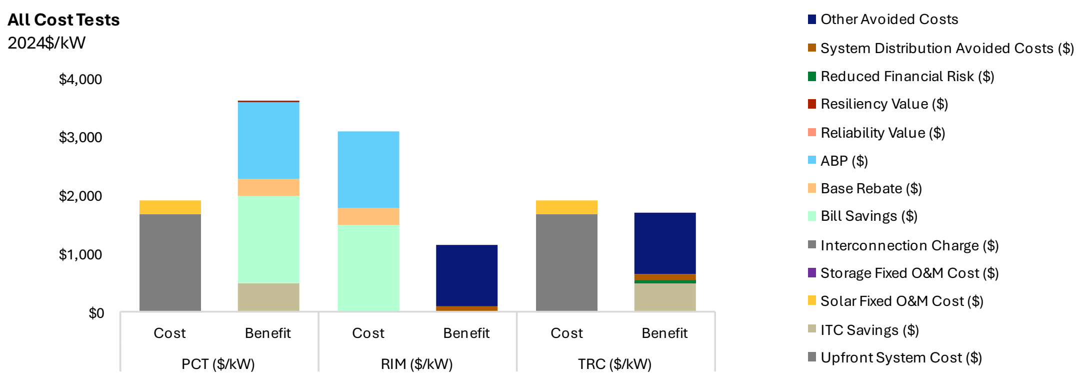
Storage – Non-LMI



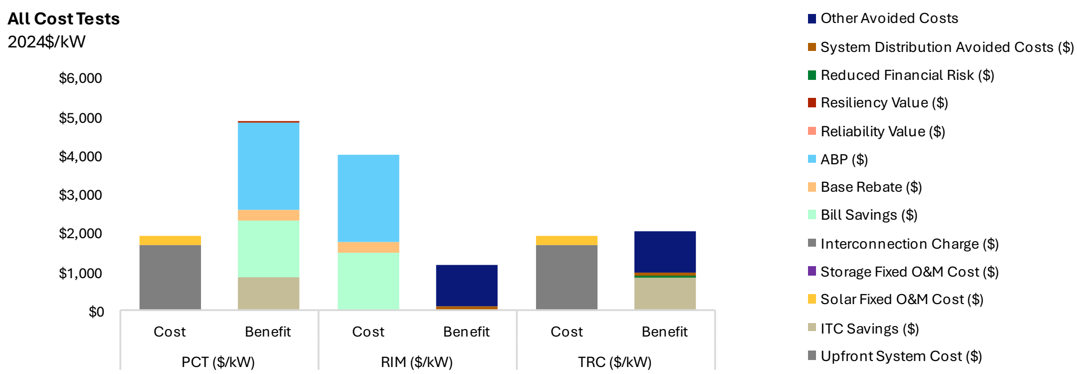
Storage – LMI



Community Solar – Non-LMI

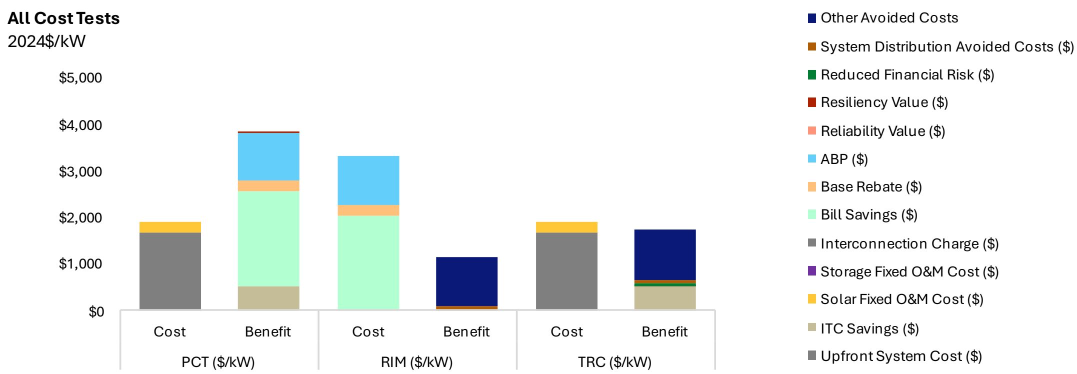


Community Solar – LMI

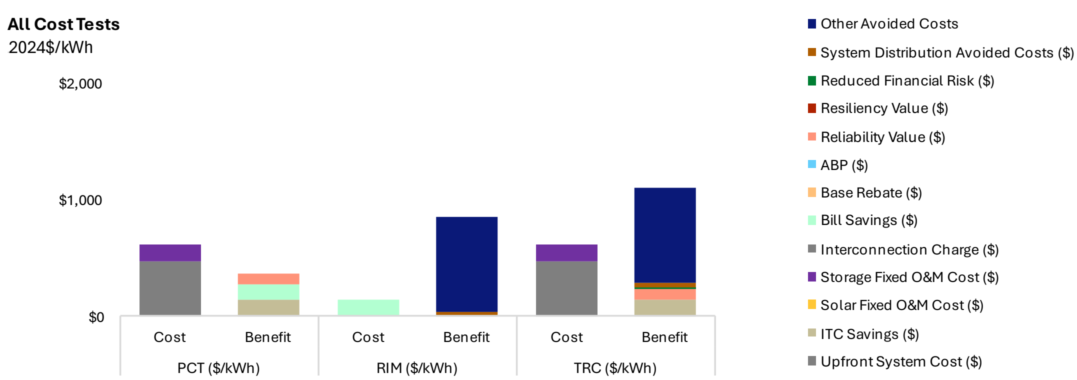


Commercial – Medium Office

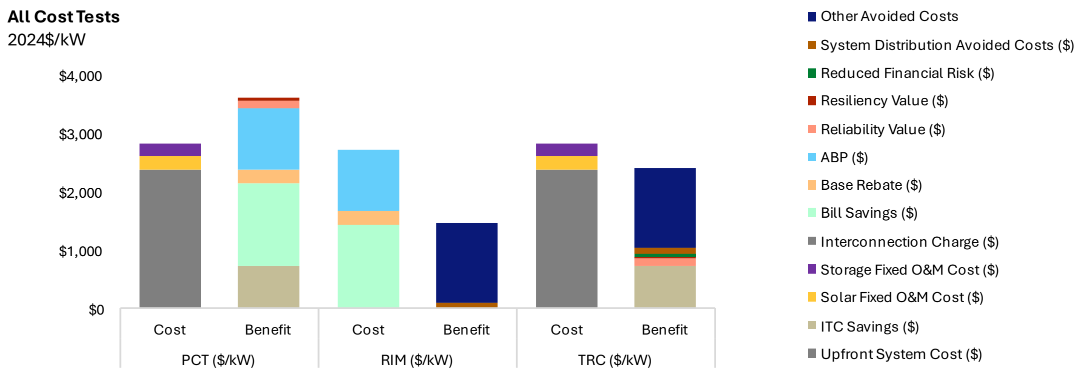
Solar



Storage

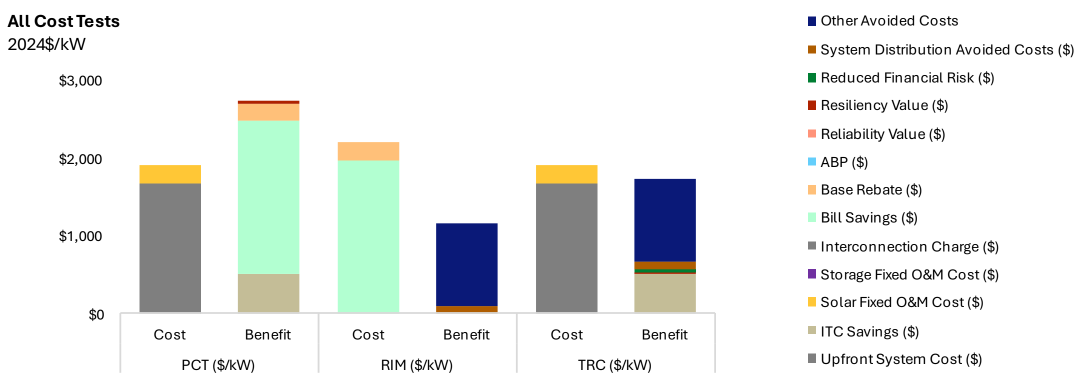


Solar + Storage

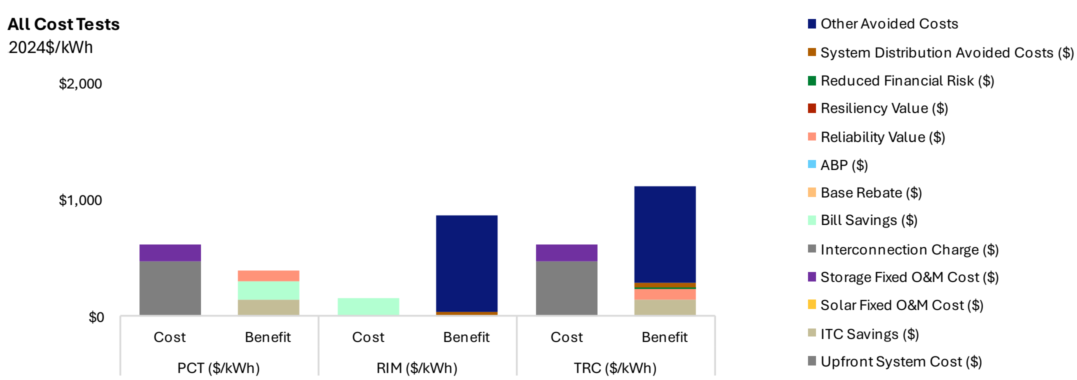


Commercial Primary School

Solar



Storage



Solar + Storage