Valuing Distributed Batteries

Benefits of an Emerging Deployment Model

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SECTION 1

Summary

Introduction

The purpose of this study is to estimate the value of distributed batteries through a repeatable framework. Distributed batteries can provide fast, flexible capacity while delivering value to the power system and participating customers.

Dual Challenges

Rising distribution costs and rapidly growing demand from data centers, electrification, and manufacturing are putting pressure on both grid capacity and customer affordability.

The Distributed Battery Solution

Distributed batteries provide fast, flexible capacity that can support both local and bulk-system needs, defer infrastructure investment, and enhance customer resilience.

Assessing the Opportunity

We estimate the value of this emerging distributed battery model relative to traditional utility-scale batteries and develop a transparent, repeatable framework that can be applied across utility systems.

ANALYSIS SCOPE

We analyze a specific distributed battery model developed by Base Power, with the following features:

- **Siting:** Batteries are hosted at residential premises and connected front-of-meter; customers receive whole-home backup at little to no cost.
- **Operation:** Batteries are modeled with a 4-hour discharge duration and dispatched to maximize bulk-system value while also providing transmission and distribution benefits.
- **Control:** Utilities have direct, real-time control and telemetry.
- **Deployment:** We compare two deployment cases: A “targeted case” in which batteries are deployed to areas with distribution capacity constraints, and an “untargeted” case in which that is not a consideration.

The added value of distributed batteries

Distributed batteries can deliver up to 66% greater system value than utility-scale batteries, by unlocking transmission and distribution benefits that are only achieved by grid-edge resources.

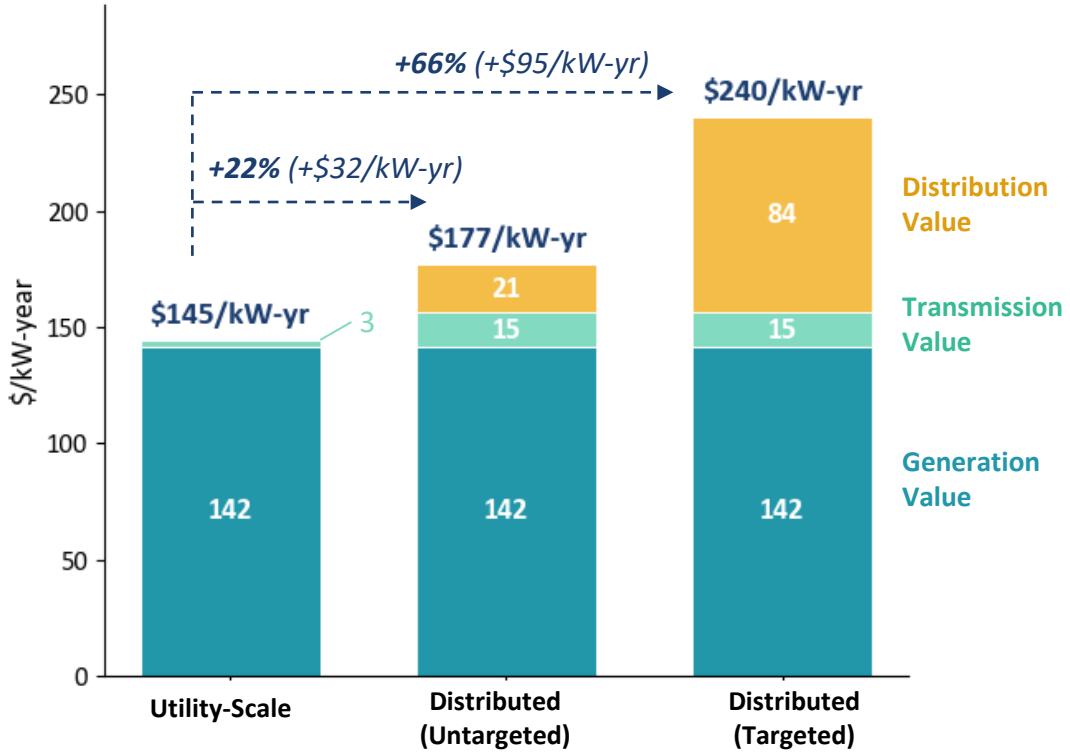
Distributed batteries can unlock local grid value in addition to bulk-system value:

- When dispatched to maximize energy and capacity value, distributed batteries provide similar generation value to utility-scale batteries.
- When battery output coincides with peak demand on feeders and substations, it can also defer load-driven distribution investments and, at sufficient scale, transmission investments.

Distributed batteries provide incremental total system value of $32/kW-yr (+22%) under untargeted deployment and $95/kW-yr (+66%) when batteries are targeted to distribution-constrained areas.

The incremental value remains material across a wide range of system conditions. Sensitivity analysis indicates that the incremental value of distributed batteries is robust across a range of market and system conditions, with some upside potential.

Annual System Value, by Battery Type



Note: Values in real 2024 dollars.

System-wide cost savings

Distributed batteries can save millions of dollars annually for a typical medium- to large-sized utility, if deployed cost competitively with utility-scale batteries.

To put the benefits in context, we scale the results to a utility of approximately 2 million residential customers, under two illustrative distributed battery deployment levels: 200 MW and 1,000 MW.

Across these scenarios, distributed batteries provide $5–$65M/year of incremental value relative to utility-scale batteries. Compared to a representative utility revenue requirement increase of $200 million/year, distributed batteries could offset up to 30% of the increase if developed at the same cost as utility-scale batteries.

	Planning-based potential deployment (200 MW)	Long-run technical potential deployment (1,000 MW)
Illustrative scale	1% of residential customers	5% of residential customers
Incremental value vs. utility-scale	$5–$17M/yr	$23–$65M/yr

ANALYSIS SCOPE

Several conditions must be met to achieve the value estimated in this study:

- The battery's load impacts must be incorporated into the load forecasting and T&D system planning process.
- Aggregate deployment must be of sufficient scale to have a meaningful impact on substation and feeder loads.
- Where battery dispatch only partially relieves a distribution constraint, additional DERs or grid investments may be required before the deferral value can be realized.
- For the targeted deployment approach, the utility must be able to identify and direct procurements toward high-value locations.
- As deployment scales, charging may need to be managed to avoid secondary battery-driven peaks on the distribution system in deployment hotspots.

SUMMARY

Overcoming the barriers

Regulators and utilities will need to address several barriers to achieving the value identified in this study.

	KEY BARRIER	POTENTIAL SOLUTION
1	**IRP models undervalue distributed storage** Often omitted, treated as demand response, or modeled with generic inputs that exclude avoided T&D.	**Model it as a dispatchable candidate resource** Use commercial cost/performance data (e.g., RFP bids) and capture capacity, energy, ancillary services, and avoided T&D.
2	**RFP eligibility excludes distributed fleets** Artificial requirements such as minimum-MW thresholds can make portfolios ineligible.	**Adapt procurement rules** Allow distributed resources to qualify as aggregated portfolios, with minimum size and site control requirements tailored to those portfolios.
3	**Evaluation methods miss the full value stack** Analysis may understate capacity accreditation, dispatchability, locational value, or distinct stacked services.	**Credit measurable system and locational benefits** Recognize RA/capacity and avoided T&D value and allow transparent value stacking across distinct services.
4	**VPP and tariff design constrain participation** Valuable features such as third-party ownership and exports to the grid may be prohibited.	**Use open, performance-based VPP structures** Enable aggregators and standalone assets, net export, dispatch incentives, and multi-year contracts.
5	**Cost assumptions may lag market conditions** Rapidly evolving distributed battery costs and business models may not be reflected in planning assumptions.	**Regularly update and benchmark resource costs** Use current market evidence and consistent cost definitions to compare distributed batteries with alternative resource options.

SECTION 2

Introduction

Background

The power sector is grappling with two significant challenges.

1 AFFORDABILITY

Household electricity bills are rising, and energy affordability has become a defining focus for policymakers, regulators, and utilities. A key driver of this trend is the cost of the distribution system, which has grown by approximately 6% annually in real terms since 2014 and has accounted for more than 30% of the national average increase in retail electricity rates.[1] Innovative, non-traditional solutions are needed to contain these costs.

2 A CONSTRAINED GRID

Rapidly growing demand for electricity – driven by data centers, electrification, and manufacturing – is outpacing the availability of traditional grid infrastructure, which is limited by supply chain constraints and lengthy development timelines. These constraints are slowing economic growth, stressing grid reliability, and introducing new challenges related to equity and fairness.

Distributed batteries are emerging as an important potential solution to these problems.

By being located close to customer load, distributed batteries have the potential to provide not only bulk system (generation and transmission) value, but also services to the distribution system, **helping to address one of the costliest steps in electricity delivery.** Additionally, host customers receive improved resilience during system outages.

Distributed batteries also are not subject to the same onerous development timeline of utility-scale resources. They can be deployed in modular increments where there is existing capacity on the distribution system. This can **accelerate load interconnection by several years** while allowing supply to more closely track load growth.

1. Lawrence Berkeley National Lab, Electric Utility Distribution Costs: Scoping Study on Trends, Drivers, and Possible Response Strategies, May 2026.

Purpose of this study

We evaluate the value of distributed batteries and provide a repeatable framework to inform utility planning.

The study has two objectives:

1 **Estimate the value of residential-sited batteries relative to utility-scale batteries for a utility system.** We specifically evaluate an emerging model for deploying and operating the batteries that is being developed by Base Power.

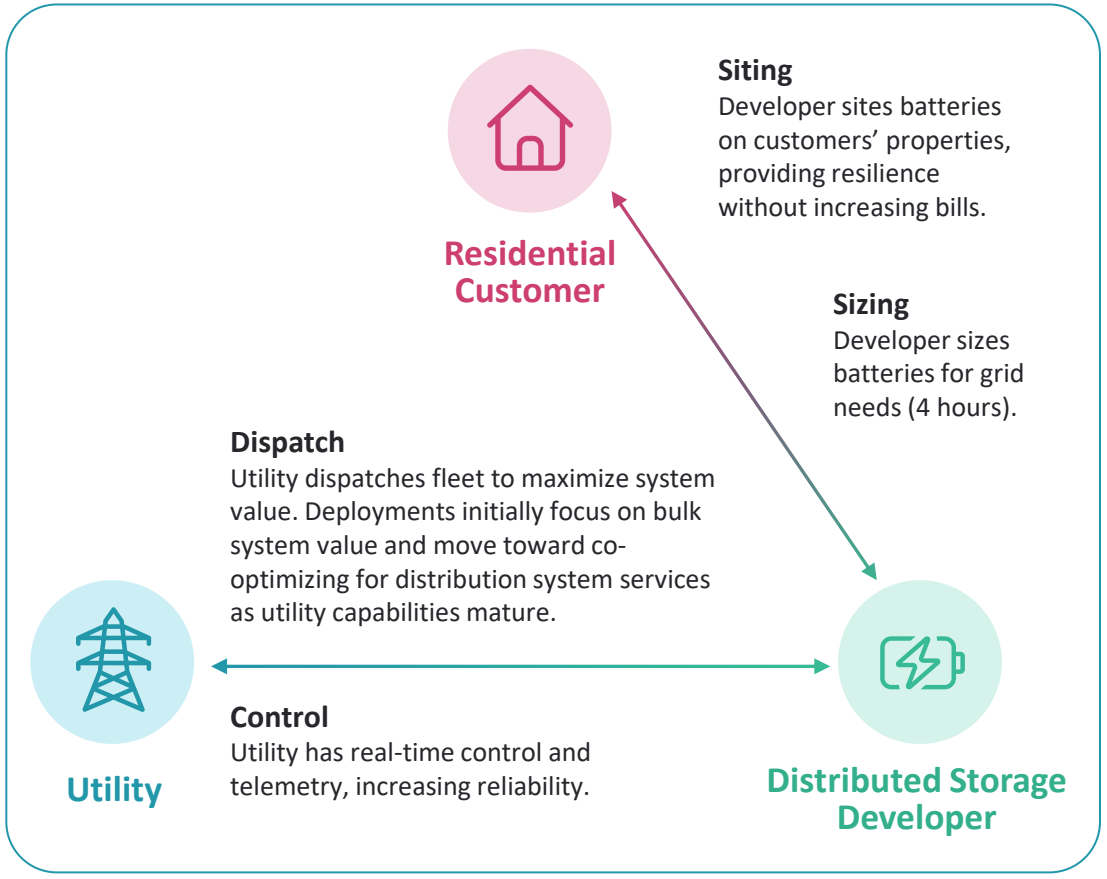
2 **Describe a repeatable methodology for estimating the value of distributed batteries that can inform utility planning and procurement.** We focus on laying out an approach for estimating distribution investment deferral value, which is a key differentiating value stream provided by distributed batteries relative to utility-scale resources.

HOW TO USE THIS STUDY

- This study focuses on storage value, not storage cost.
- Planners should use the methodology to estimate value and then separately assess cost-effectiveness based on procurement, installation, program, and operating costs.
- The analysis assumes a level of distributed battery deployment sufficient to contribute to distribution investment deferral. It is not a forecast of maximum achievable adoption or total addressable market.
- The methodology in this study can help inform integrated resource planning and procurement analysis; it should not be used as a replacement for detailed transmission and distribution planning studies.
- The analysis is tied to utility data where applicable and otherwise relies on plausible assumptions. Any utility applying the framework should update the inputs to reflect its own system characteristics.

An emerging model for distributed battery development

Our analysis focuses specifically on an emerging approach to battery development with unique features related to siting, size, control, and dispatch. These features can drive value for both customers and the utility.



Siting
The batteries are distributed but effectively sit in front of the customer's meter: they provide resilience benefits to the host customer during an outage, but do not impact their load or bill. Participating customers allow the battery to be sited on their property and receive whole-home backup at little to no cost.

Sizing
Battery size is decoupled from household load and optimized for grid needs. We model a residential battery with a 4-hour duration.

Control
Utilities have direct, real-time control and telemetry of the batteries, allowing distributed batteries to be dispatched 24/7 with the same level of orchestration and reliability as utility-scale batteries.

Dispatch
In our model, we assume the batteries are dispatched to maximize their bulk system value. In restructured markets, this means maximizing capacity, energy, and ancillary services value. In vertically integrated markets, this means maximizing generation and grid balancing value. We then quantify the incremental distribution value that results from that dispatch pattern (*see next section for further discussion*).

SECTION 3

Analysis Scope

Scope Overview

We use recent market and utility data to simulate the value of distributed and utility-scale batteries to the power system.

GEOGRAPHY

Where relevant, we draw on MISO data and data from a Midwestern utility to estimate battery value. The utility's cost and load characteristics are broadly similar to those of many US utility systems, so the estimates provide a useful illustration of potential battery value. These data do not fully characterize the conditions on a particular distribution system; further, system-specific analysis would be needed to support planning or investment decisions.

VALUE

We quantify the generation, transmission, and distribution value that can be provided by the batteries, with a particular focus on distribution value, as this is the key differentiator in resource value between distributed and utility-scale batteries. This perspective on value is generalizable to both restructured and vertically integrated utilities. Other important sources of value from distributed batteries (e.g., speed of deployment) are discussed qualitatively.

STUDY HORIZON

We use historical and forecasted market price, transmission system, and distribution system cost data for the period between 2024 and 2039.

SCALE

Initially, we present battery value per kilowatt of storage nameplate capacity on an annualized basis (i.e., $/kW-yr). Then, we illustrate how that value would scale to the utility level under two scenarios of future distributed battery deployment.

SENSITIVITY ANALYSIS

We test the sensitivity of our results to a broad range of distribution system conditions, to explore the robustness of our findings regarding the incremental value of distributed batteries.

Quantified sources of battery value

Batteries can "stack" several value streams. By being located at the edge of the grid, distributed batteries are positioned to provide additional value that is incremental to that of transmission-connected batteries.

GENERATION

In wholesale markets, batteries provide capacity value, energy price arbitrage (both temporal and between day ahead and real-time markets), and ancillary services (e.g., frequency regulation, spin). In vertically integrated utilities there are analogous value streams, including avoided capex investment in other resource types, energy cost savings by shifting load from hours with higher marginal energy costs to hours with lower marginal energy costs, and real-time balancing services that take advantage of the near-instantaneous response and ramp rate of batteries. **Both utility-scale and distributed batteries can provide this value, as long as the distributed batteries provide sufficient control and telemetry.**

TRANSMISSION

Batteries sited near load in transmission-constrained areas may help defer upgrades needed to serve growing demand if they reliably relieve the relevant constraint. **Distributed batteries are located at customer premises and are therefore more likely than a typical utility-scale portfolio to be deployed in populated load areas. This creates a potential advantage for addressing load-growth-related transmission needs.** Both distributed and transmission-connected batteries can provide this value when appropriately located and operated; project-specific studies would be needed to determine whether either deployment could defer a particular upgrade (see appendix for further detail).

DISTRIBUTION

If batteries can discharge to serve load downstream of a substation or feeder at times when that equipment otherwise would be capacity constrained, batteries can create system headroom and contribute to distribution investment deferral opportunities. **Only distributed batteries can provide this value**, because transmission-connected (utility-scale) batteries are located upstream of the distribution system. We discuss the potential source of this value throughout this report.

How the distributed batteries provide value: An illustration

Distributed batteries can charge during low-cost hours and discharge during high-value system peak periods, while also creating distribution headroom when bulk-system and local peaks coincide.

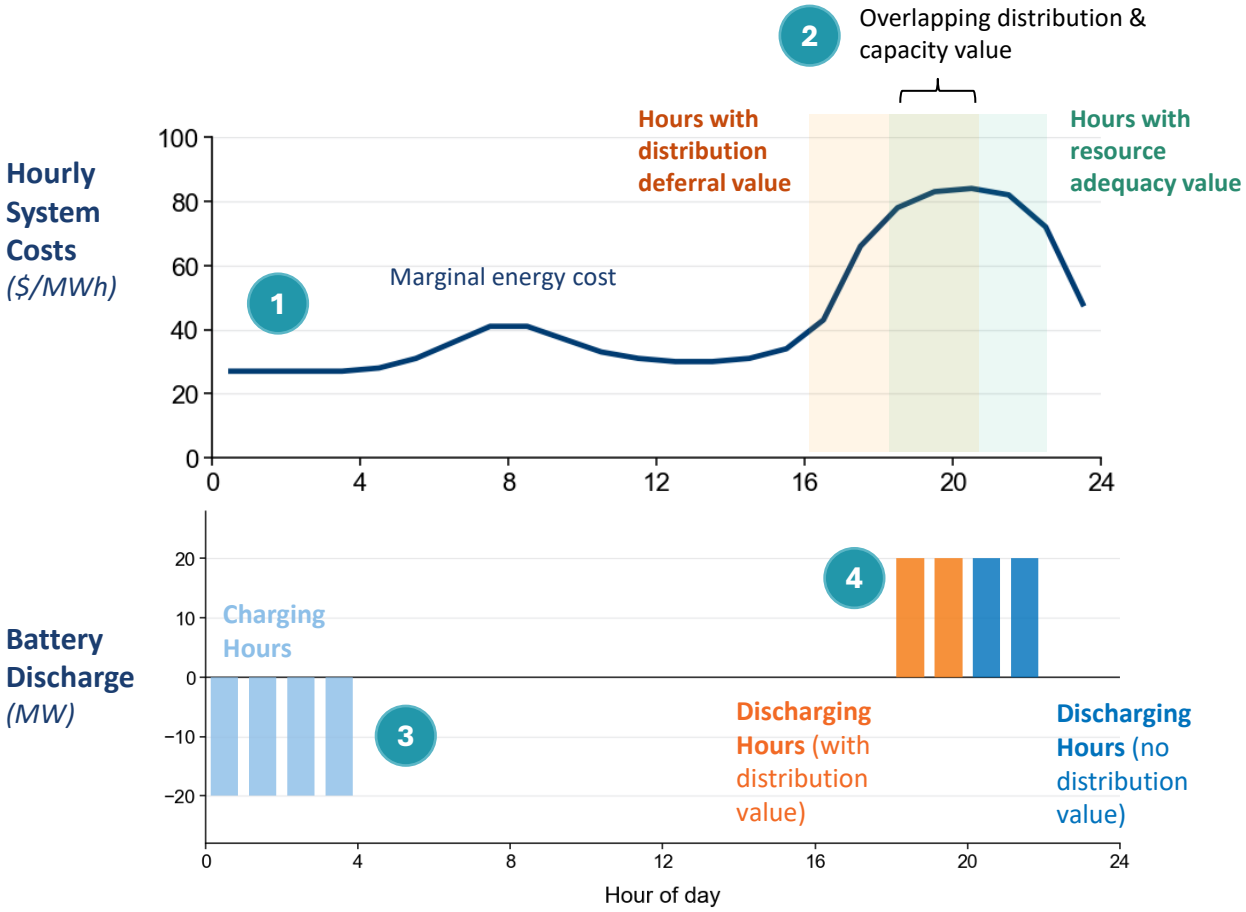
1. During off-peak hours, energy costs are low and there are typically no distribution capacity constraints or resource adequacy needs.

2. During evening peak hours, resource adequacy needs and marginal energy costs are highest. Local distribution constraints may partially overlap with these same hours.

3. The battery charges when the system is unconstrained and marginal costs are low, helping minimize system costs and, under rapid load growth, improve asset utilization.

4. Battery dispatch prioritizes bulk-system value (energy and resource adequacy). When dispatch coincides with local distribution peaks, it can also create distribution headroom. In this study, we use this overlap as a proxy for Distribution Load Carrying Capability (DLCC)* rather than estimating DLCC through full statistical analysis.

**See Section 5 for description of DLCC.*



Two battery deployment cases

We analyze two approaches to deploying the distributed batteries; one which targets deployment specifically at constrained locations of the grid, and another that does not.

CASE 1: UNTARGETED DEPLOYMENT

In the Untargeted case, batteries are deployed anywhere customers are willing to host them, without explicit consideration for whether they can provide near-term distribution value. This limits the average per-kilowatt distribution value of the battery fleet as a result.

CASE 2: TARGETED DEPLOYMENT

In the Targeted case, batteries are deployed specifically to capacity-constrained locations of the distribution system, elevating the per-kW distribution value of the fleet. This could be achieved through locational incentives and targeted customer outreach, an approach already being used by some utilities (e.g., National Grid's ConnectedSolutions+).

Other Deployment and Operation Models

These cases are just a subset of ways in which distributed batteries can be deployed and operated.

In other applications, the batteries may be operated as "grid-aware" resources and dispatched with distribution system value as the priority. This would increase distribution value relative to our estimates and, if combined with bulk system value, could lead to a larger overall value.

Other deployment methods could include aggregating behind-the-meter batteries for utility or RTO/ISO dispatch through VPP/DER aggregation programs or connecting standalone batteries to the distribution system without a host customer.

Section 5 discusses considerations for estimating the distribution value of a broader range of use cases.

Analysis framework

The analysis uses a repeatable, screening-level framework to estimate battery value.

	1 Estimate generation value	2 Estimate transmission value	3 Estimate distribution value
Input	• Battery configuration and performance characteristics • Marginal generation capacity, energy and ancillary services (balancing) costs • Battery effective load carrying capability (ELCC)	• Share of battery capacity located near load (100% of distributed batteries, 20% of utility-scale batteries based on interconnection queue data) • Per-kW cost of load growth-driven planned transmission projects	• Battery dispatch profile (from step 1) • Number of load-driven substation upgrade needs across the system over a 10-year planning period • Average cost of substation capacity expansion projects • Multiplier to account for downstream feeder upgrade costs • Timing of substation- and feeder-level peak demand conditions
Analysis	• Simulate dispatch of battery to maximize energy and ancillary services / balancing value • Apply ELCC to marginal capacity cost to assign capacity value	• Credit avoided marginal transmission cost to the portion of battery capacity sited near load; calculate blended average value per-kW of battery capacity, accounting for share that is not located in load pocket	• Establish marginal cost of distribution capacity, with consideration for locations that do not require upgrades • Calculate weighted average marginal cost of distribution capacity in locations with battery deployment, with different weights in the Untargeted and Targeted cases • Estimate coincidence of battery discharge profile with top 50 substation- and feeder-level peak demand hours • Calculate contribution of batteries to valuable distribution load reductions based on the factors above
Output	• Battery dispatch profile • Total generation value ***Distributed value = utility-scale value***	• Transmission value ***Distributed value > utility-scale value***	• Distribution value ***Distributed value only***

See Appendix for additional detail.

See Section 5 for additional detail.

SECTION 4

Key Findings

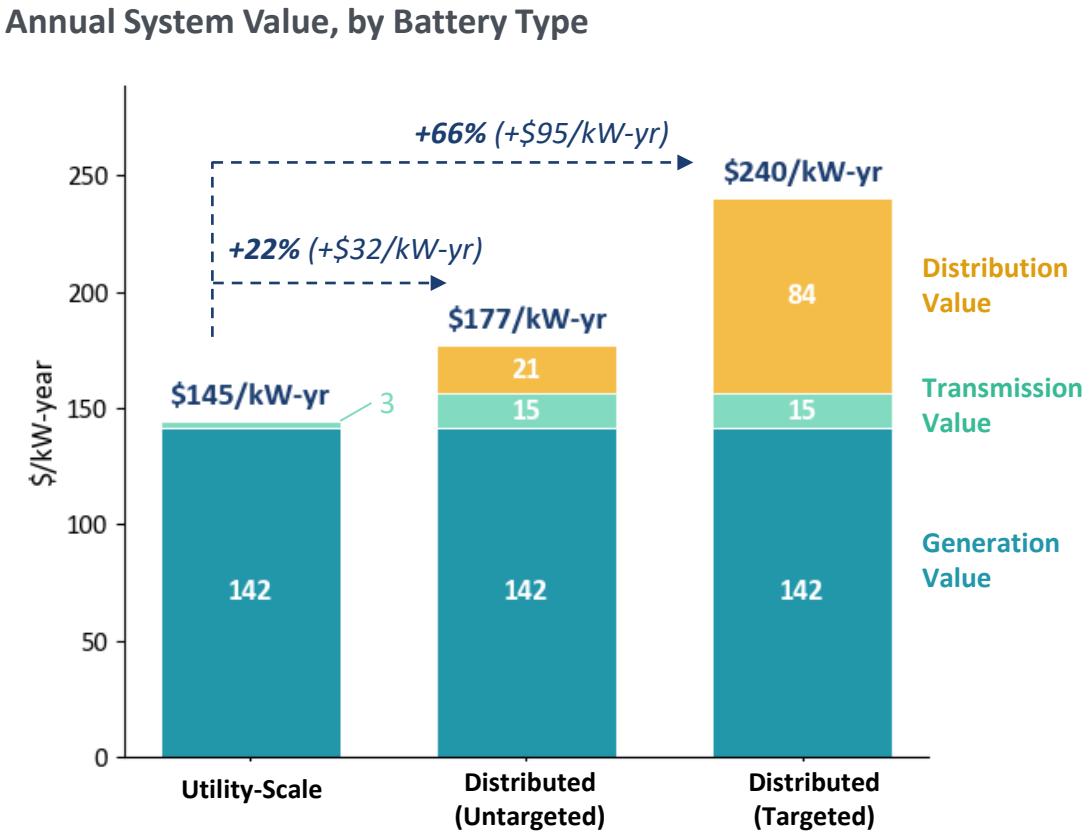
The added value of distributed batteries

By being located at the grid edge, distributed batteries can provide transmission and distribution investment deferral value that is incremental to the generation value provided by utility-scale batteries.

When dispatched to maximize bulk system energy and capacity value, distributed batteries can provide equivalent generation value (i.e., energy and capacity) to utility-scale batteries with the same configuration.

Additionally, as resources located at the end of the distribution system, distributed batteries can help to delay load-driven constraints on the distribution system when their output coincides with the peak demand on feeders and substations. Some transmission investment relief is possible as well, if capacity of the distributed batteries reaches sufficient scale.

Consequently, the average system value of distributed batteries is 22% higher ($32/kW-yr) than utility-scale batteries when adopted broadly across a utility service territory (i.e., non-targeted deployment). This average incremental value increases to 66% ($95/kW-yr) when the distributed batteries are deliberately deployed exclusively to capacity-constrained areas of the distribution grid.

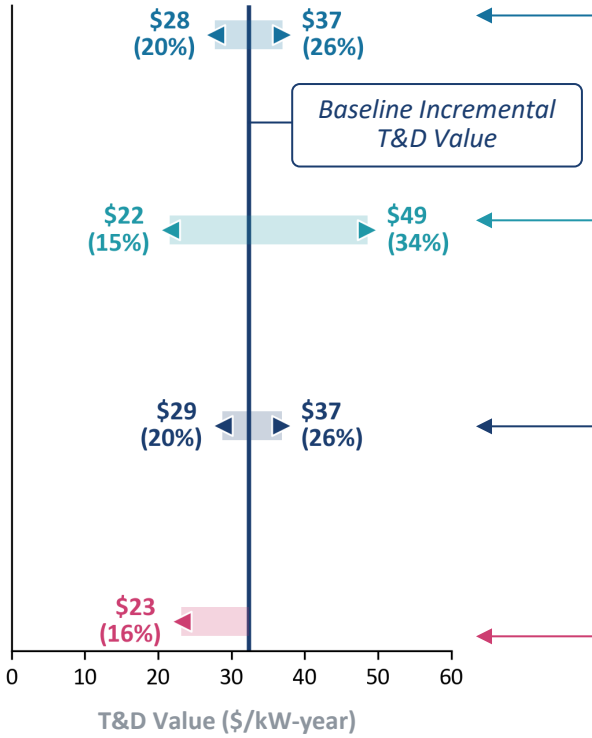


Note: Values in real 2024 dollars.

Sensitivity analysis results for Untargeted Deployment

System conditions vary across utilities, yet untargeted distributed batteries provide robust value across a range of system characteristics; the T&D value represents a 15% to 34% boost in value relative to utility-scale system benefits.

T&D Value Across Sensitivities
Untargeted Battery Deployment



Note: Percentages reflect the incremental value provided compared to the utility-scale battery.

Distribution Load Carrying Capability

The extent to which generation value-optimized battery dispatch naturally aligns with local, distribution-level peak-loading hours determines how much distribution load the battery can relieve. We vary substation and feeder coincidence factors by ±10% from default assumptions of 50% and 40%, respectively, supported by a review of coincidence factors at utilities in other jurisdictions. In general, utilities with larger shares of residential load and/or significant cooling load are likely to experience higher coincidence factors.

Share of Constrained Substations

The share of substations and feeders expected to require capacity upgrades over the study horizon represents the addressable market for distribution investment deferral. We vary the constrained share of the system from a 15% baseline assumption to 10% and 20%. Utilities with lower average load hosting capacity (e.g., those that are less overbuilt or have experienced recent distribution-level load growth) are likely to have a larger share of their system requiring near-term load-driven upgrades.

Equipment Costs

Deferral value increases as the cost of new distribution system equipment rises. Our base analysis uses project costs from a Midwestern utility. Sensitivity cases apply a ±20% adjustment to all project costs to represent plausible variation across US utilities. Higher costs are more likely for utilities serving dense urban areas or constrained sites, where land, labor, permitting, underground construction, and complex rebuilds of aging substations can increase the total cost of developing additional capacity.

Feeder Upgrades

Feeder deferral requires sufficient battery deployment within a relatively concentrated area. The baseline assumes both substation and feeder upgrades can be deferred, while a conservative sensitivity excludes feeder value and attributes distribution benefits only to substation deferrals. Feeder value is most likely to be achievable where residential load is concentrated, and capacity shortfalls are modest relative to feeder size. This sensitivity case isolates the distribution value to be fully attributable to substation upgrade deferrals.

System-wide cost savings

Scaling the estimates to a representative utility with 2 million residential customers indicates incremental value of up to $65 million, which could materially stem future growth in electricity bills.

	Planning-based market potential scenario	Long-run technical potential scenario
	Assumes 200 MW of distributed battery deployment, equivalent to roughly 1% of the illustrative utility's residential customers having a battery, or 10% of the utility's storage capacity need being addressed with distributed batteries.	Assumes 1,000 MW of distributed battery deployment, equivalent to roughly 5% of the illustrative utility's residential customers having a 10 kW battery, or distributed battery capacity equivalent to roughly 10% of system peak demand.
Non-targeted Deployment	**$5M** p.a. savings relative to utility-scale	**$23M** p.a. savings relative to utility-scale
Targeted Deployment	**$17M** p.a. savings relative to utility-scale	**$65M** p.a. savings relative to utility-scale

Context: Compared with a representative annual utility revenue requirement increase of $200 million, the estimated net savings from distributed batteries could offset up to roughly 30% of the increase if the batteries could be developed and deployed at the same cost as utility-scale batteries. This could significantly mitigate rate pressure for consumers.

Notes: Brattle analysis and illustrative assumptions. Gross annual system value should not be interpreted as the payment or revenue available to the battery developer. The 10% distributed battery share assumption and the 10% peak-management share are illustrative planning assumptions. The Untargeted Scenario assumes battery capacity deployment proportional to peak load under each substation. The Targeted Deployment scenario assumes 100% of battery capacity is deployed under the 15% of substations that are capacity-constrained within the study horizon. See Appendix for more detail.

Additional benefits

Several additional benefits are not quantified in our analysis but are key drivers of the distributed battery value proposition.

SPEED
Faster Deployment

Distributed batteries can be deployed quickly, because they avoid long generation interconnection lead times and are not subject to significant supply chain constraints. **Distributed batteries can be online in 1-2 years**, compared to 3-5 years for utility-scale batteries or 5-10 years for new gas generation, thus playing a key role in relieving current supply bottlenecks.

AFFORDABILITY
Lower Cost Burden

The distributed battery business model analyzed in this study virtually eliminates upfront cost barriers to consumers through third-party ownership, financing, and VPP payments. Customers gain access to battery resilience benefits **with no direct battery investment cost**. The added incremental value of the batteries can provide system benefits to all ratepayers.

RESILIENCE
Backup and Reliability

The standalone residential-sited batteries analyzed in this study are approximately 40 kWh each. This modular size, combined with faster speed of deployment, allows the battery capacity to grow with load and **reduces stranded asset risk due to load forecasting uncertainty.**

MODULARITY
Scalable and Flexible

If configured appropriately, distributed batteries can **provide downstream backup power during system outages**. As a result, host customers could power critical loads in their homes for several days while electric service is out.

SECTION 5

Framework for Estimating Distribution Value

Framework overview

The framework proposed in this study measures the location-specific cost of serving load growth, credits only the DER output that can reliably contribute to addressing distribution capacity constraints and reflects DER portfolio siting and operating choices in the application of the framework.

BATTERY PORTFOLIO DISTRIBUTION VALUE = **MCOS in battery-sited locations** × **DLCC of the battery portfolio in battery-sited locations**

1

Marginal Cost of Service (MCOS) Study: Locate and price grid needs

Forecast local constraints and calculate MCOS—the annualized cost of serving an incremental kW of load in each location. Many locations will have sufficient grid capacity and therefore, zero MCOS.

2

Distribution Load Carrying Capability (DLCC) Study: Accredit DER capacity

Model DLCC—the contribution of DER operation to meeting the distribution grid need based on asset load shape and the timing, duration, and magnitude DER operation.

3

DER Value: Apply MCOS and DLCC based on DER siting and operations

Account for whether DERs are in the right locations and operate at the right times. Cap total value based on the expected distribution capacity need over an appropriate time horizon.

This framework can be broadly applicable to various types of DER deployment models, including programs, rates, and procurement mechanisms.

FRAMEWORK FOR ESTIMATING DISTRIBUTION VALUE

Calculating the locational marginal cost of service

Location-specific MCOS is a key input for estimating the distribution value of DERs.

$$\text{MCOS } (\$/kW\text{-}yr) = \frac{\text{PV of annualized incremental distribution cost to serve forecasted load growth}}{\text{PV of cumulative annual forecasted load growth}}$$

The metric represents the annualized cost of serving a kW of incremental load in a location, given the forecasted load growth, available grid capacity, and cost of expanding grid capacity.

Numerator: Distribution system cost to serve forecasted load growth

1. **Forecast asset-level constraints**
   Identify when forecasted load exceeds planned capability. Planned capability should be adjusted to reflect any capacity expansion projects already in progress.
2. **Estimate mitigation cost**
   Develop ballpark solution costs where planning-grade estimates are unavailable. Locations without constraints within the study period are zero marginal cost. The study period should match the lifetime of the DER assets being evaluated.
3. **Convert to annual ratepayer cost**
   Apply an economic carrying charge reflecting the utility's pre-tax weighted average cost of capital (WACC), O&M, property taxes, and other applicable revenue-requirement components.
4. **Discount to present value**
   Use the same WACC as the discount rate.

Denominator: Forecasted load growth

1. **Measure cumulative annual load growth**
   Forecast growth relative to the location's existing load. Sum the annual kW peak that is incremental to the base year's peak.
2. **Discount over the same study horizon**
   Use the same study period and discount rate as the numerator.

FRAMEWORK FOR ESTIMATING DISTRIBUTION VALUE

Illustrative MCOS calculation for a constrained substation

At this illustrative substation, load is forecast to exceed available capacity in 2035. Based on the projected load growth and the cost of addressing the constraint, the MCOS in this location is $84/kW-year, calculated through the steps outlined below.

1 Forecast the capacity need

Projected peak load exceeds the 22.5 MW substation rating in 2035.

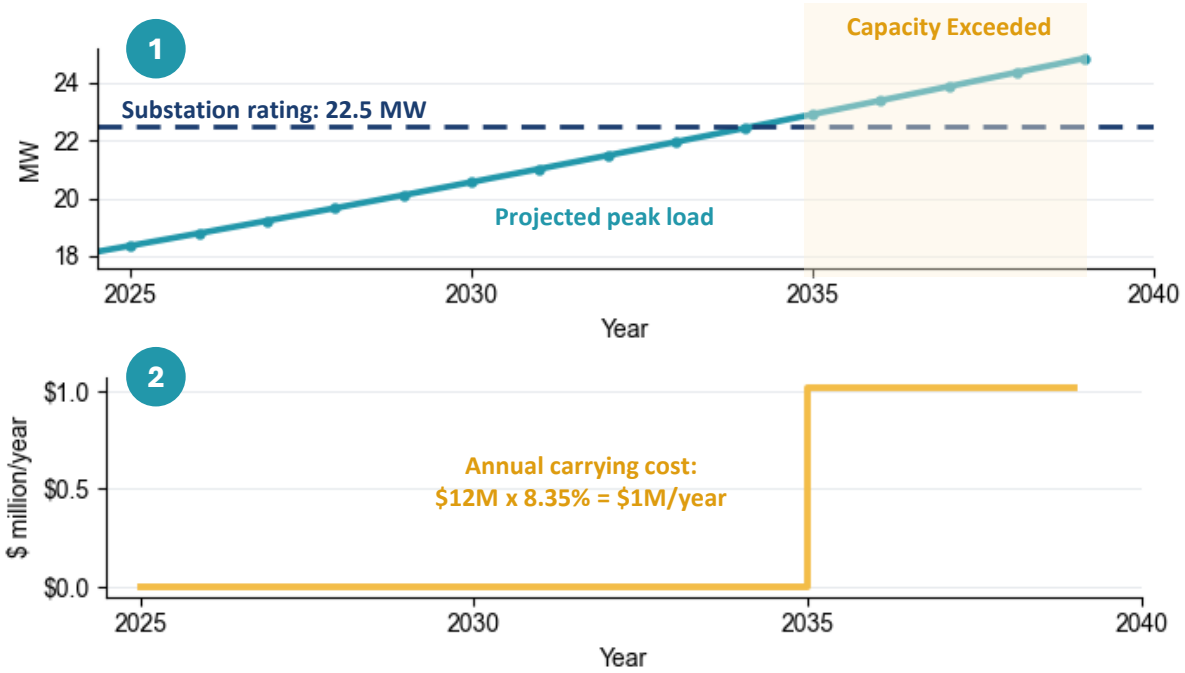
2 Estimate and annualize the upgrade cost

$12 million upgrade is required in 2035. It is converted to an annual ratepayer cost using an 8.35% real economic carrying charge.

3 Levelize cost over load growth

Over the 2025–2039 study period, the present value of annual carrying costs is divided by the present value of cumulative annual load growth:

- PV of annual carrying costs: $3.2 million
- PV of annual incremental load growth above the 2025 base year load: 38 MW-years



$$\text{MCOS } (\$/kW\text{-yr}) = \frac{\text{PV of annualized incremental distribution cost to serve forecasted load growth}}{\text{PV of cumulative annual forecasted load growth}} = \frac{\$\ 3.2\ M}{38\ MW\text{-year}} = \$\ 84/kW\text{-yr}$$

The levelized distribution capacity cost associated with incremental load growth at this location is $84/kW-year over the study period.

Using the MCOS to estimate the locational value of a DER

The MCOS represents the levelized incremental cost to serve each kW of load growth in a location. Additional steps are needed to use this metric to estimate the value of a DER's expected operation.

Establish resource-specific distribution load carrying capability

The extent to which a DER can reliably reduce loading on a specific distribution asset depends on the operating characteristics of the DER and the load profile on the distribution asset. A location- and technology-specific distribution load carrying capability metric should be used to represent this for planning and valuation purposes.

See next page for an illustrative DLCC calculation.

Establish maximum distribution capacity need

Each forecasted distribution constraint is based on a specific amount of load growth exceeding the existing grid capacity. This represents a cap on the amount of load reduction that can lead to avoided/deferred costs in the location within the study horizon. Once sufficient capacity is added to the system to mitigate the constraint, additional capacity does not have incremental distribution value within the study horizon. Caps should be identified for each location to represent this maximum valuable capacity.

Select appropriate study and contract horizon

The MCOS metric is defined such that the DER asset's distribution value should be locked into the calculated value for the entire study period. This raises certain key considerations when selecting the study horizon:

- The study horizon should be equal to the DER asset's lifetime or contract period.
- The contract period should be long enough to provide the developer/customer with reasonable revenue certainty.

STUDY UPDATES

All studied metrics should be updated on a frequent cadence to reflect conditions that can change the value of DERs. MCOS can change with new load forecasts and solution costs/timing. DLCCs can diminish as more DER capacity is installed in a location or increase if load shapes change and become more coincident with DER operation.

Defining distribution load carrying capability

A location- and resource-specific DLCC should be developed to account for the extent to which a DER can reliably reduce loading on a specific distribution asset given the expected operating characteristics of the DER.

1 Forecasted asset load profile

The load shape of the distribution asset will determine the timing of load reductions needs.

2 Target load reduction

Set a meaningful level of target load reduction based on the forecasted rate of load growth and limit exceedance at the asset. The illustration shows a 5% reduction. This identifies the timing and duration of load reductions needed for meaningful distribution value in this location.

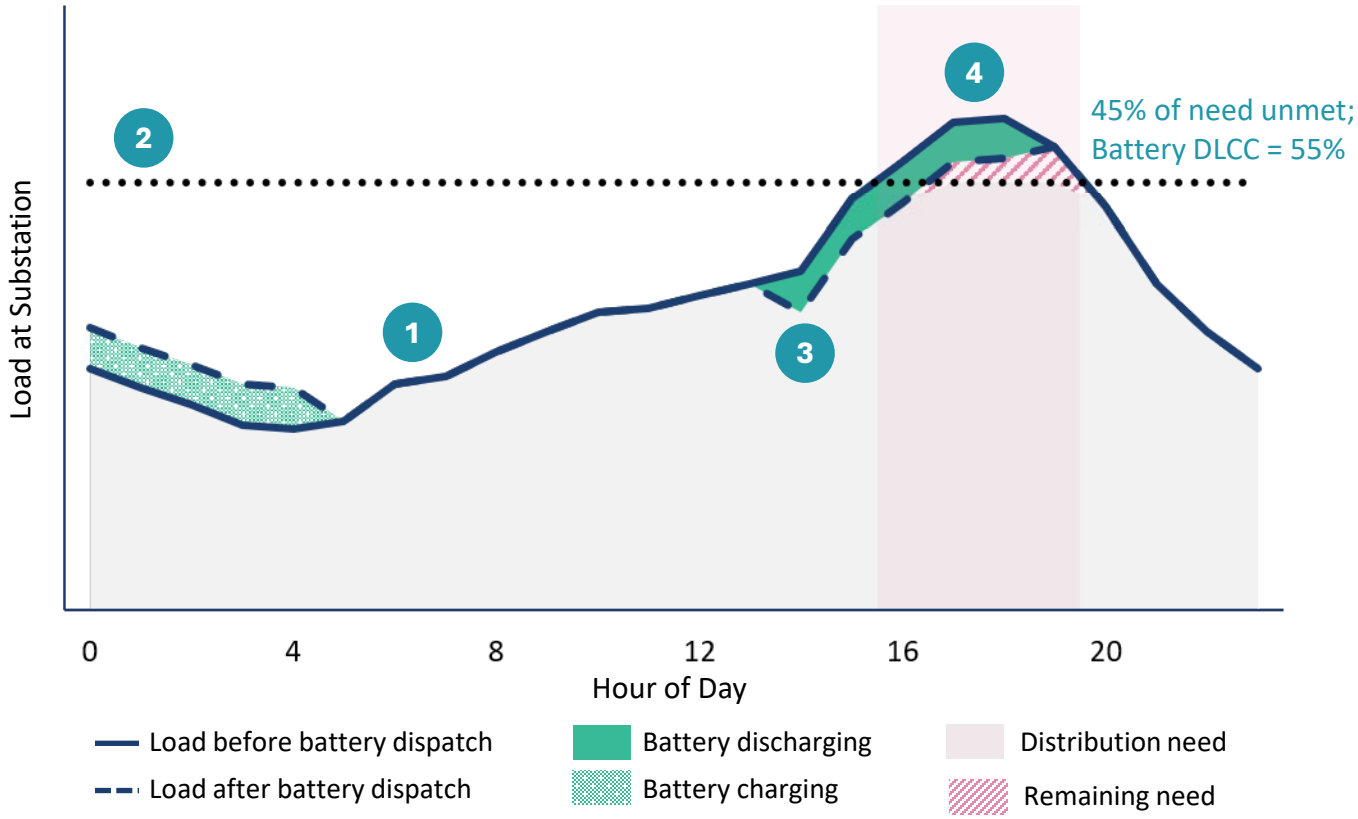
3 Expected DER operating profile

The magnitude, duration, frequency, and timing of load reductions that the DER is expected to provide. In this study, the battery's operation is modeled based on the hours of high energy prices, with no consideration of distribution grid needs.

4 Load carrying contribution

The fraction of the DER's output that is likely to contribute to meeting the distribution grid need. Where data is available, this analysis can be conducted probabilistically, with consideration of different possible load shapes and DER operating profiles.

Illustrative DLCC Analysis for Batteries at a Substation



FRAMEWORK FOR ESTIMATING DISTRIBUTION VALUE

DLCC proxy used in this study

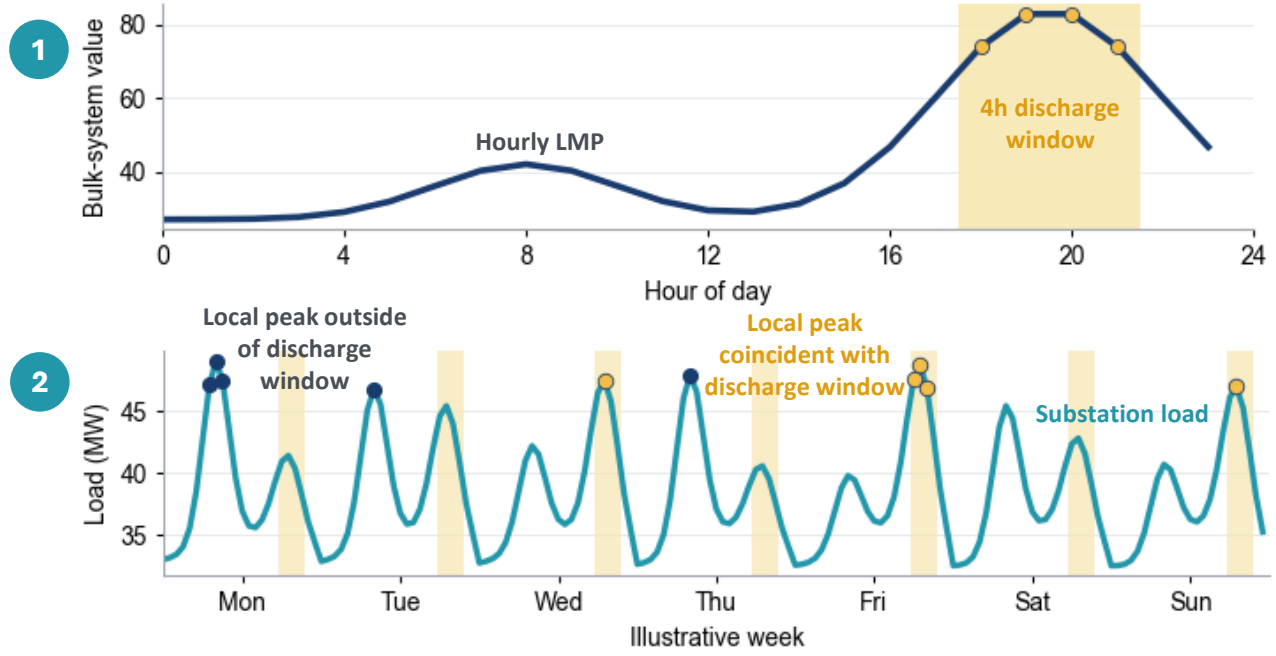
In this study, battery operation is optimized based on energy prices. The distribution load reductions stemming from this use case are dependent on the alignment between high energy prices and the hours that drive local distribution grid needs. We use this price-load coincidence as a proxy for DLCC.

1 Identify expected discharge hours

Identify when batteries are likely to discharge based on the intended use case. For the 4-hour batteries in this study, we selected the four highest LMP hours of each day of the year.

2 Measure coincidence with local peaks

Select a representative set of critical load hours for each asset and measure how often they overlap with expected battery discharge. To develop the proxy DLCC used in this study, we considered the top 50 annual load hours of a sample of substations. When selecting critical load hours, planners should consider how many hours of load reductions are needed to produce a meaningful peak load reduction on a location-specific basis; areas with flatter load shapes will require more hours of load reduction.



$$DLCC = \frac{Number\ of\ identified\ critical\ asset\ load\ hours\ that\ overlap\ with\ dispatch\ hours}{Total\ number\ of\ critical\ asset\ load\ hours}$$

Note for utility implementation: This method provides a screening-level proxy rather than formal DLCC estimate. Following initial battery deployments, utilities should use actual dispatch, availability, and measured performance to develop the DLCC. We use empirical substation and feeder load data and nodal energy prices from a US utility to develop the illustration in this study.

FRAMEWORK FOR ESTIMATING DISTRIBUTION VALUE

DLCC proxy developed based on real-world data

We used historical load and energy price data for a utility in PJM to develop the DLCC proxy used in this study. The data shows that across this utility's 41 substations, the coincidence between energy prices and top 50 distribution load hours ranges from 8% to 76%, with a weighted average of 44%. The range of coincidence factors shows the importance of conducting granular analysis to determine DLCCs.

Consider location-specific load shapes. Define critical hours at the asset level because peak timing, duration, and shape vary materially across locations.

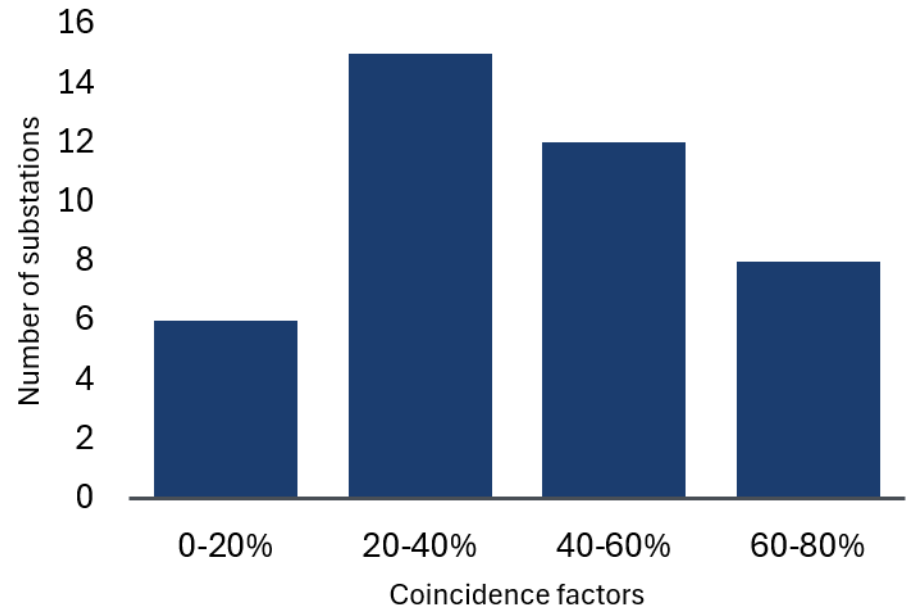
Use multiple years of data. Capture inter-annual weather and operating variation rather than relying on a single potentially atypical year.

Test potential future load and energy-price shapes. Electrification, DER adoption, generation mix, and market conditions may shift both local peaks and expected battery dispatch.

Refresh and calibrate DLCCs over time. Update estimates as load patterns change and validate assumptions using actual dispatch, availability, and measured performance.

Simplified assumptions are unlikely to result in realizable distribution value. As shown by the range of factors, applying the average in all locations would result in over- or under-accreditation of battery capacity and value in many locations.

Coincidence Between High Energy Price and Peak Substation Load Hours – Distribution Across 41 Substations at a Sample Utility

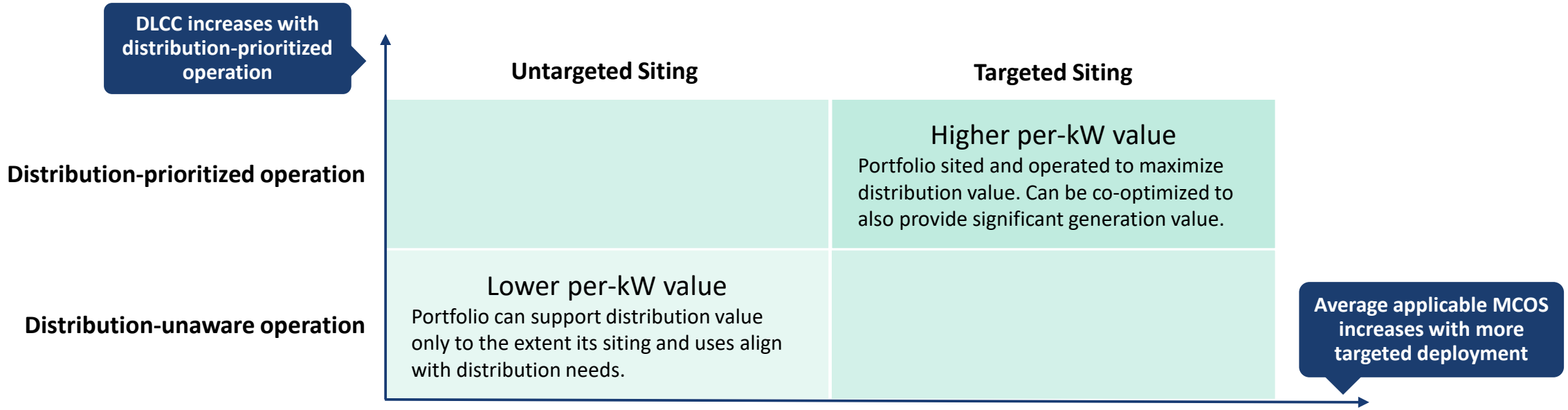


FRAMEWORK FOR ESTIMATING DISTRIBUTION VALUE

Potential siting strategies and operating modes

Siting strategy and operational priority are key determinants of the distribution value of distributed battery portfolios. A portfolio sited in locations with distribution constraints and operated to mitigate those constraints will have higher value than a geographically untargeted portfolio that prioritizes bulk system value streams.

BATTERY PORTFOLIO DISTRIBUTION VALUE = **MCOS in battery-sited locations** × **DLCC of the battery portfolio in battery-sited locations**



Potential evolution of the distribution use case

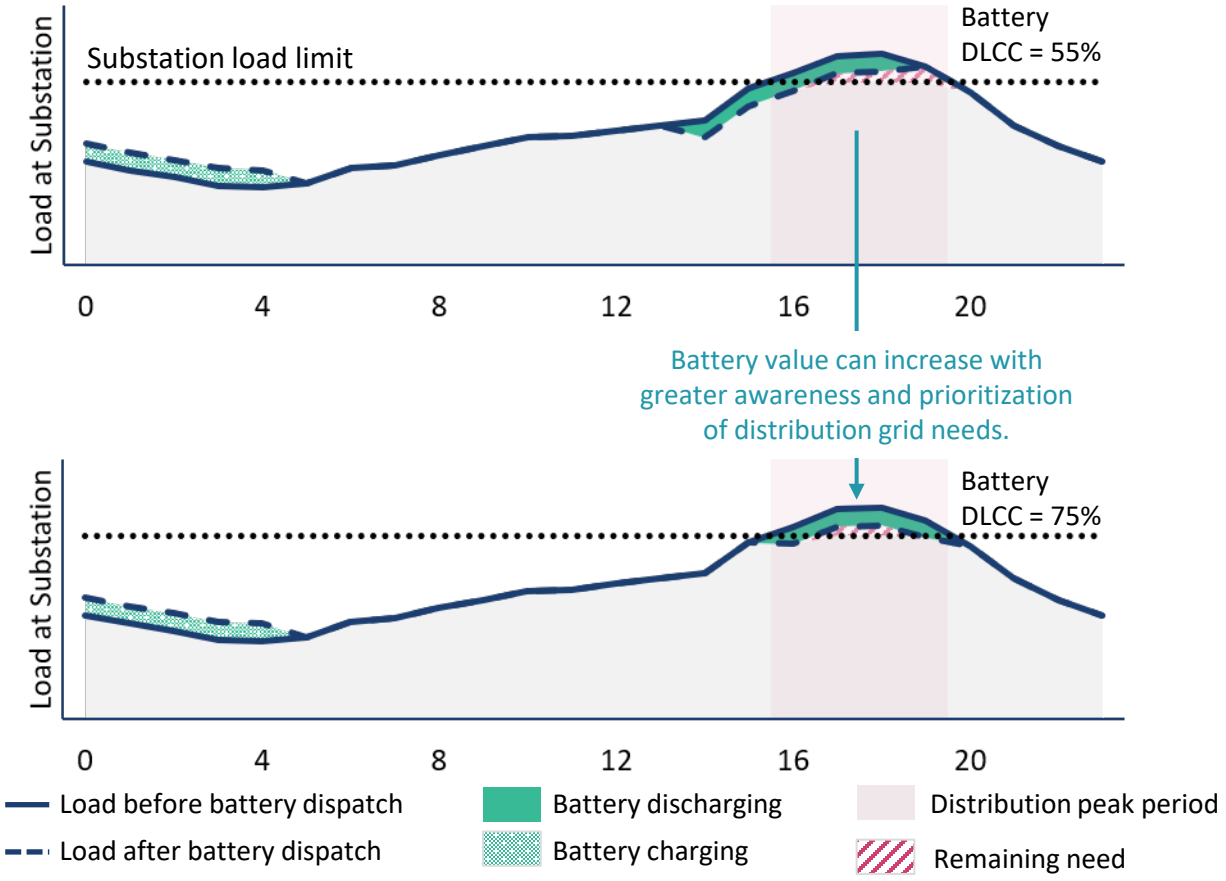
Utilities can move from relying on the coincidental distribution value arising from broad system-wide deployment to more optimized value created through targeted deployment and operation as DER orchestration capabilities evolve.

Distribution-unaware operation – *Lower DLCC*

This study focuses on the most likely operational strategy for distributed batteries deployed today – providing bulk system value. There are some T&D benefits arising from this type of operation, but they are lower than if the batteries were to be operated primarily as T&D assets. Planners generally account for this type of T&D impact through the load forecasting process, with load forecast modifiers to account for DER impacts on future T&D loads.

Distribution-prioritized operation – *Higher DLCC*

As utilities' DER orchestration capabilities evolve over time, distribution batteries can transition from being forecasted load modifiers to optimized T&D assets. This evolution will require development of utility planning and operational procedures and grid IT/OT systems, in addition to programmatic mechanisms that will allow the orchestration of DER deployment and operation. Optimization for distribution may involve some tradeoffs with other value streams, but the overall value stack has the potential to increase significantly.



SECTION 6

Conclusion

Overcoming the barriers

Regulators and utilities will need to address several barriers to achieving the value identified in this study.

	KEY BARRIER	POTENTIAL SOLUTION
1	**IRP models undervalue distributed storage** Often omitted, treated as demand response, or modeled with generic inputs that exclude avoided T&D.	**Model it as a dispatchable candidate resource** Use commercial cost/performance data (e.g., RFP bids) and capture capacity, energy, ancillary services, and avoided T&D.
2	**RFP eligibility excludes distributed fleets** Artificial requirements such as minimum-MW thresholds can make portfolios ineligible.	**Adapt procurement rules** Allow distributed resources to qualify as aggregated portfolios, with minimum size and site control requirements tailored to those portfolios.
3	**Evaluation methods miss the full value stack** Analysis may understate capacity accreditation, dispatchability, locational value, or distinct stacked services.	**Credit measurable system and locational benefits** Recognize RA/capacity and avoided T&D value and allow transparent value stacking across distinct services.
4	**VPP and tariff design constrain participation** Valuable features such as third-party ownership and exports to the grid may be prohibited.	**Use open, performance-based VPP structures** Enable aggregators and standalone assets, net export, dispatch incentives, and multi-year contracts.
5	**Cost assumptions may lag market conditions** Rapidly evolving distributed battery costs and business models may not be reflected in planning assumptions.	**Regularly update and benchmark resource costs** Use current market evidence and consistent cost definitions to compare distributed batteries with alternative resource options.

CONCLUSION

An opportunity to support affordability and economic growth

Distributed batteries can help meet growing grid needs faster while delivering value beyond traditional, utility-scale resources.

This study set out to analyze the potential value of an emerging approach to distributed battery deployment. We found that unique features of the model would allow the batteries to address significant challenges currently facing the power sector.

Addressing a critical need

Rapid load growth, rising distribution costs, and limited grid headroom are increasing the value of flexible, modular resources that can be deployed close to customers.

Significant value

Distributed batteries can provide the same bulk-system energy and capacity value as utility-scale storage, while adding transmission and distribution investment deferral, resilience, faster deployment, and affordability benefits. **We estimate total system value that is 22% above utility-scale storage with broad deployment, and 66% above when distributed battery portfolios are targeted to constrained locations.**

Achieving the value

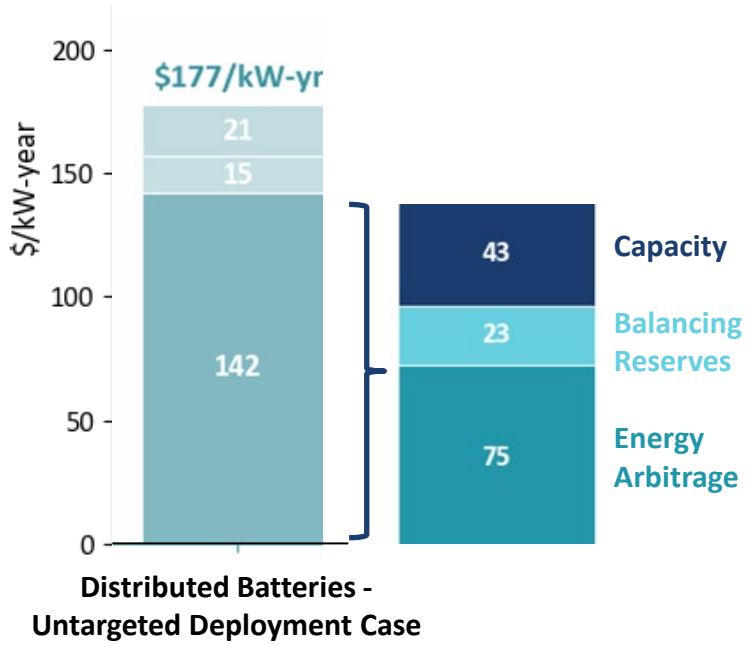
The incremental benefit is not automatic. It depends on where and at what scale the batteries are deployed, whether dispatch aligns with local grid needs, and whether utilities can manage charging as well as discharging.

SECTION 7

Technical Appendix

Calculation of generation value

Energy, spinning-reserve, and capacity values form the common wholesale market value foundation for all battery deployment cases in this study.



Distributed Batteries - Untargeted Deployment Case

Note: The $142/kW-year wholesale-market value is the same for utility-scale, targeted and untargeted battery deployment. The untargeted deployment bar is shown only to illustrate where the common wholesale-market value sits within the full untargeted battery value stack.

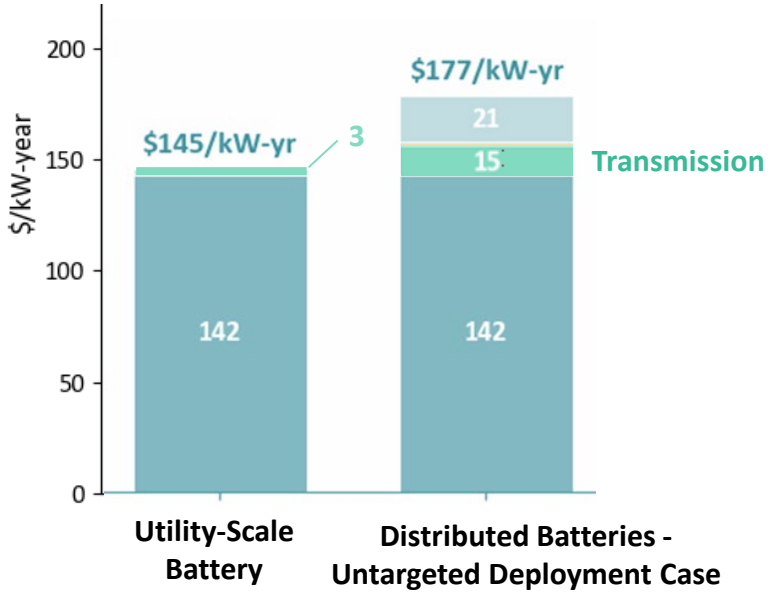
Modeling Approach	Data Requirements
Capacity Value: Capacity value reflects the battery's accredited contribution to meeting MISO resource-adequacy needs. For each season, we apply the storage accreditation percentage from MISO's indicative DLOL results to the LRZ 7 Net CONE value for Planning Year 2025/26. We then convert the seasonal results into an annual capacity value expressed in $/kW-year.	Capacity inputs include the MISO LRZ 7 Net CONE value for Planning Year 2025/26 and the seasonal storage accreditation percentages from MISO's indicative LOLE/DLOL results[1].
Balancing Reserves: A Brattle-developed battery dispatch model co-optimizes day-ahead energy and spinning-reserve participation for every hour of the year. The optimization respects the battery's power rating, energy duration, charging and discharging efficiency, and state-of-charge limits. Spinning-reserve revenue is calculated using hourly MISO reserve prices.	Market-price inputs include hourly MISO day-ahead and real-time LMPs and hourly spinning-reserve prices[2]. Battery operating inputs include the power rating, energy duration, round-trip efficiency, charging and discharging limits, and allowable state-of-charge range.
Day-Ahead and Real-Time Energy Arbitrage: The same optimization model calculates day-ahead energy-arbitrage value using hourly MISO LMPs and perfect price foresight. We then apply an incremental real-time value adder calibrated from prior Brattle analyses of imperfect-foresight day-ahead and real-time operation. This adder captures the additional value of adjusting the day-ahead position in the real-time market without assuming perfect real-time foresight.	

1. MISO Cost of New Entry (CONE) and Net CONE Calculation for Planning Year 2025/2026. Values are in $/MW-day. MISO, "LOLE Study Results PY 2025-2026". The Even Loss Scenario is used in value stack calculations.
2. Purchased from Hitachi Energy Velocity Suite Power Prices.

APPENDIX

Calculation of transmission value

Transmission value reflects avoided load-growth-driven grid investment and depends on whether the battery is connected close enough to load to defer that investment.



Note: Both distributed battery cases receive $15/kW-year in transmission value, versus approximately $3/kW-year for utility-scale batteries after the 20% location factor.

The modeled DER-BESS receive a higher transmission value estimate than the utility-scale BESS because the study assigns all DER-BESS capacity to urban counties, which it uses as a proxy for greater load-growth-related transmission needs. By comparison, approximately 20% of utility-scale BESS capacity is assigned to urban counties, based on the locations of projects in the interconnection queue. This reflects the study's geographic allocation assumption; neither urban county location nor customer siting alone establishes that a battery can relieve a particular transmission constraint. Project-specific electrical and operational analysis would be needed to determine whether either portfolio could defer a particular transmission project. A utility-scale BESS deliberately sited to address such a constraint could also provide substantial value.

Modeling Approach	Data Requirements
TRANSMISSION VALUE **Estimate Marginal Transmission Cost:** We select MTEP25 projects classified as load-growth projects with expected in-service dates from 2026 through 2030. We sum their reported costs, converting them from assumed 2025 dollars to real 2024 dollars. **Annualize the Value:** We divide the total project cost by the increase in MISO annual coincident peak load from 2026 to 2030, then apply a 8% real economic carrying charge to estimate an annual transmission cost per kW of peak-load growth. We apply an 80% battery capture factor to estimate the value available to batteries. **Apply the Location Adjustment:** Both distributed battery cases receive the resulting transmission value. Utility-scale batteries receive 20% of that value, reflecting the share of active Michigan battery capacity in the MISO interconnection queue located in urban counties. The difference is the estimated incremental value under these siting assumptions. Urban location is a proxy for potential access to load-growth-related transmission value; it does not establish that a battery can defer a particular project.	• Project inputs include MTEP25 project costs and project drivers[1]. • Load inputs include MISO's long-term forecast of coincident peak-load growth. Financial inputs include nominal WACC, long-run inflation assumption, fixed O&M factor, and transmission-asset life[2]. • Siting inputs include active Michigan battery projects from the MISO Generator Interconnection Queue and the HUD county classification used to identify urban locations[3].

1. MISO Transmission Expansion Plan 2025 (MTEP25).
2. MISO Long-Term Load Forecasting (2025). DTE nominal WACC calculated from most recent approved DTE rate of return reported in S&P Global.
3. Brattle analysis of the MISO Generator Interconnection Queue, using the HUD Urban Counties classification.

APPENDIX

Illustrative deployment scenarios and distribution value

The 200 MW and 1,000 MW cases are illustrative and bracket near-term planning and long-run technical potential; realized distribution value depends on how deployment aligns with modeled substation needs.

Planning-based market potential scenario (200 MW)

The 200 MW planning case uses DTE Electric's approved storage resource plan strictly for context, while remaining an illustrative market assumption.

DTE's most recent IRP (2022 CleanVision) targets more than 1,800 MW of energy storage in 2023-2042[1]. We assume that distributed batteries could provide approximately 10% of the 1.81 GW storage plan.

The illustrative 10% share is therefore a planning assumption (not a DTE or MPSC forecast). As an additional reasonableness check, 200 MW is equivalent to approximately 20,000 base-sized 10 kW installations[2], or about 1% of the utility's approximately 2 million residential accounts[3].

Long-run technical potential scenario (1,000 MW)

The 1,000 MW case represents a long-run technical-potential benchmark. For context, DTE's forecast 2026 system peak is approximately 10 GW, making 1,000 MW about 10% of system peak[4].

A separate customer-adoption calculation produces nearly the same result: 5% of approximately 2 million residential accounts x 10 kW per Base installation = 1,000 MW.

Because the calculation does not adjust for customer eligibility, adoption economics, battery availability, local grid constraints, or deployment timing, it should be interpreted as a long-run technical ceiling, not an expectation of realized adoption.

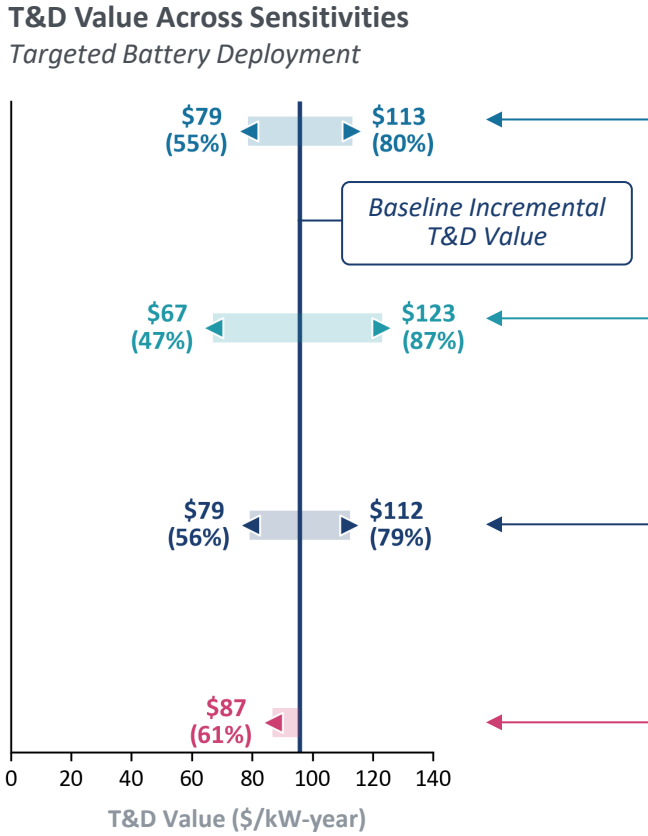
Distribution value calculation ($ millions)

Storage is allocated using the load-growth weights underlying the MCOS calculation. In the *untargeted* case, the total battery deployment is distributed across all substations according to these systemwide load weights, whereas in the *targeted* case it is allocated only among constrained substations. At each constrained substation, credited capacity is limited to the lesser of the modeled overload and 50% of the allocated battery nameplate capacity, reflecting the assumed coincidence between battery dispatch and local distribution needs. Credited capacity is valued using the full substation-specific locational MCOS. The total distribution value is calculated by summing the substation-level values across all constrained substations and adding the systemwide feeder value, which is applied to the entire battery deployment.

1. Michigan Public Service Commission, "Commission Approves Settlement Agreement on DTE Electric Co.'s Integrated Resource Plan," July 26, 2023, 2022 DTE IRP, "CleanVision"; identifies DTE's target of more than 1,800 MW of storage by 2042.
2. Base Power, Hardware Specifications; identifies ~40 kWh of energy capacity. Assume 10 kW per installation when battery is discharged as a 4-hour resource. https://www.basepowercompany.com/specs/core.
3. U.S. Energy Information Administration, Form EIA-861, 2024 Final Data; source for utility-level residential customer counts.
4. DTE Electric Company, Qualifications and Direct Testimony of Markus B. Leuker, MPSC Case No. U-21860, filed April 24, 2025, pp. MBL-34–MBL-35. DTE reports a 2023 service-area peak demand of 10,853 MW and forecasts a 2026 annual peak demand of 10,706 MW.

Sensitivity analysis results for Targeted Deployment

System conditions vary across utilities, yet targeted distributed batteries provide robust value across a range of system characteristics; the T&D value represents a 47% to 87% boost in value relative to utility-scale system benefits.



Note: Percentages reflect the incremental value provided compared to the utility-scale battery.

Distribution Load Carrying Capability

The extent to which generation value-optimized battery dispatch also naturally aligns with local, distribution-level peak-loading hours determines how much distribution load the battery can relieve. We vary substation and feeder coincidence factors by ±10% from default assumptions of 50% and 40%, respectively, supported by a review of coincidence factors at utilities in other jurisdictions. In general, utilities with larger shares of residential load and/or significant cooling load are likely to experience higher coincidence factors.

Share of Constrained Substations

The share of substations and feeders expected to require capacity upgrades over the study horizon represents the addressable market for distribution investment deferral. We vary the constrained share of the system from a 15% baseline assumption to 10% and 20%. Utilities with lower average load hosting capacity (e.g., those that are less overbuilt or have experienced recent distribution-level load growth) are likely to have a larger share of their system requiring near-term load-driven upgrades.

Equipment Costs

Deferral value increases as the cost of new distribution system equipment rises. Our base analysis uses project costs from a Midwestern utility. Sensitivity cases apply a ±20% adjustment to all project costs to represent plausible variation across US utilities. Higher costs are more likely for utilities serving dense urban areas or constrained sites, where land, labor, permitting, underground construction, and complex rebuilds of aging substations can increase the total cost of developing additional capacity.

Feeder upgrades

Feeder deferral requires sufficient battery deployment within a relatively concentrated area. The baseline assumes both substation and feeder upgrades can be deferred, while a conservative sensitivity excludes feeder value and attributes distribution benefits only to substation deferrals. Feeder value is most likely where residential load is concentrated, and capacity shortfalls are modest relative to feeder size. This sensitivity case isolates the distribution value to be fully attributable to substation upgrade deferrals.

For further information



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