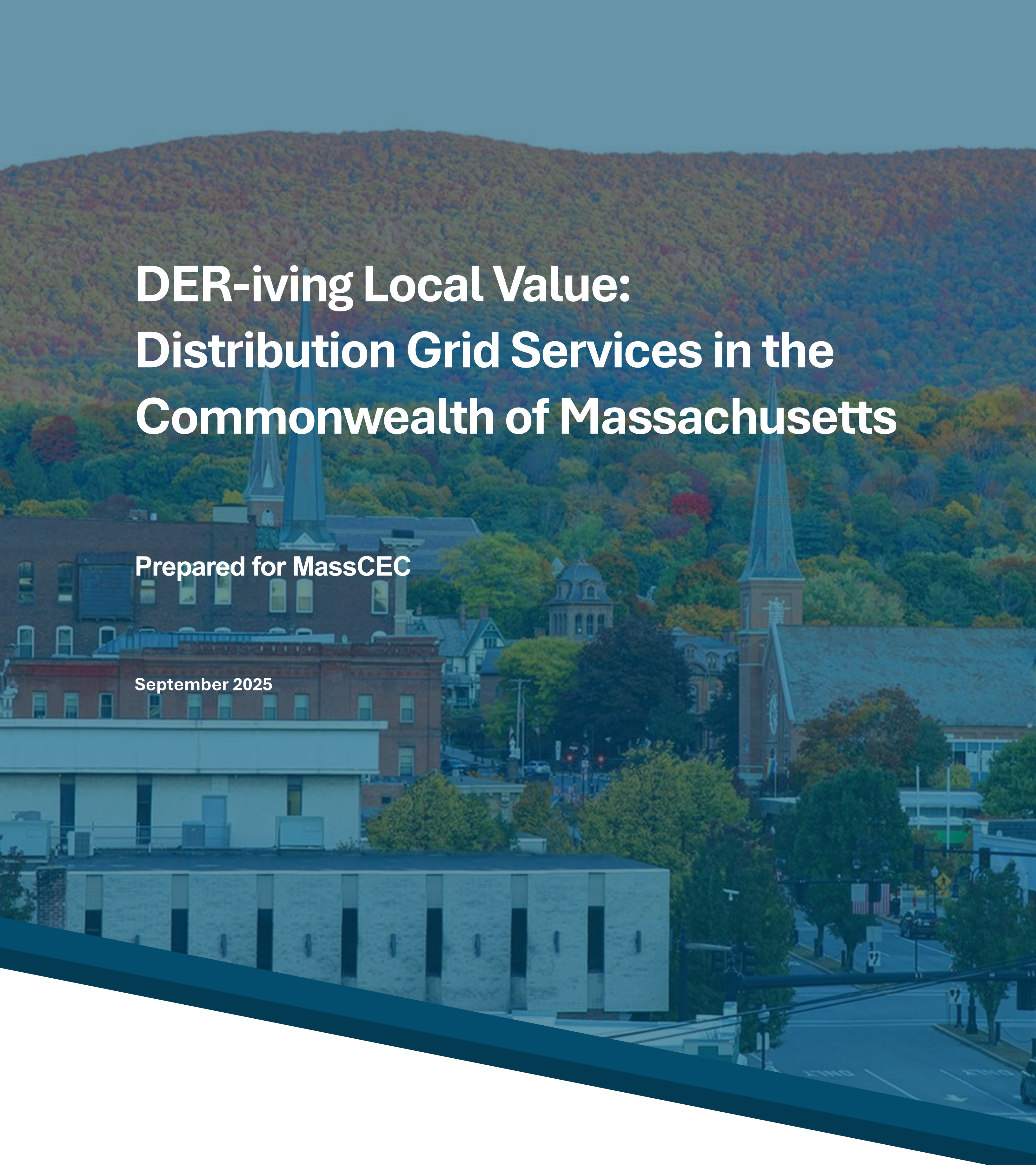

DER-iving Local Value: Distribution Grid Services in the Commonwealth of Massachusetts

Prepared for MassCEC

September 2025

Energy+Environmental Economics

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Table of Contents

Figures

Tables

List of Acronyms

Acronym	Definition
ACEEE	American Council for an Energy-Efficient Economy
ACP	Alternative Compliance Payment
ADMS	Advanced Distribution Management Systems
AESC	Avoided Energy Supply Components
AGO	Attorney General's Office
BCA	Benefit-Cost Analysis
BTM	Behind-the-Meter
CAIDI	Customer Average Interruption Duration Index
COBRA	Co-Benefits Risk Assessment
CPEC	Clean Peak Energy Credits
CPS	Clean Peak (Energy) Standard
CS	ConnectedSolutions
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management Systems
DOE	Department of Energy
DOER	Department of Energy Resources
DPU	Department of Public Utilities
EDC	Electric Distribution Company
EJ	Environmental Justice
EJC	Environmental Justice Community
EPA	Environmental Protection Agency
ESMP	Electric Sector Modernization Plan
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission

Acronym	Definition
FTM	Front-of-the-Meter
GHG	Greenhouse Gas
GWh	Gigawatt-hour
ICE	Interruption Cost Estimate
ISO-NE	Independent System Operator - New England
LBNL	Lawrence Berkeley National Laboratory
LEAP	Local Energy Action Program
LMI	Low or Moderate Income
MW	Megawatt
MWh	Megawatt-hour
NEM	Net Energy Metering
NOx	Nitrogen Oxides
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
NWA	Non-Wires Alternative
PIMs	Performance Incentive Mechanisms
RMI	Rocky Mountain Institute
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SMART	Solar Massachusetts Renewable Target
SOx	Sulfur Oxides
V2G	Vehicle-to-Grid
WACC	Weighted Average Cost of Capital

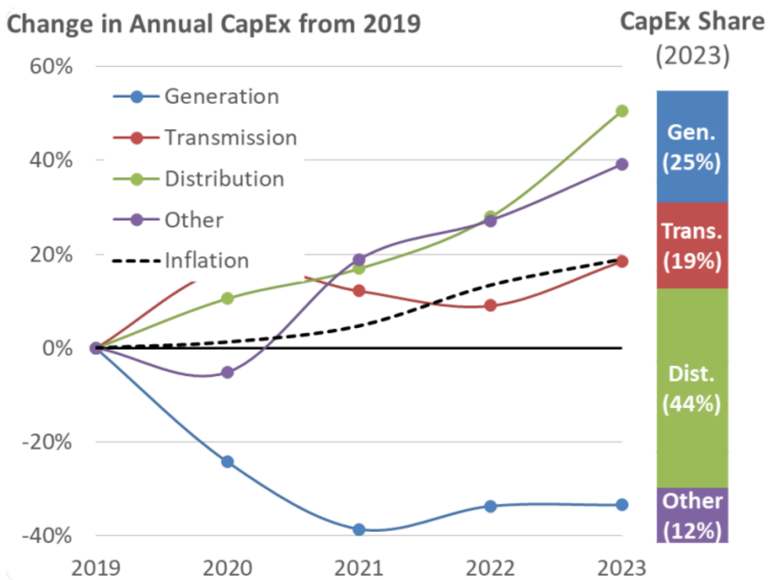
Additional industry-related acronyms and term definitions can be found in the glossary of the Grid Services Primer, included as Appendix B.

Executive Summary

Across the Commonwealth of Massachusetts and the entire United States, recent increases in electric rates have brought conversations around energy affordability into the spotlight. While the specific causes of rate increases merit a nuanced conversation, the need to use every available tool to put downward pressure on rates is obvious. Given this urgent need, states with ambitious climate goals are challenged to find how the vehicles of decarbonization, such as Distributed Energy Resource (DER) deployment, can create novel paths to affordability.

Distribution system spending accounts for a large fraction of utility revenue requirements, so cost control of this component may be a valuable lever to promote affordability. Modernization of the distribution grid is critical to maintain reliability, ensure resiliency in the context of a changing climate, replace aging infrastructure, and accommodate load growth including end use electrification. However, as Figure 1 from Lawrence Berkeley National Laboratory (LBNL) and the National Renewable Energy Laboratory (NREL) shows, the push for modernization is driving increases in capital spending that outpace growth in other categories. This motivates an important question: how can utilities, state agencies, and regulators find the least cost pathways to modernizing the distribution system and supporting decarbonization?

Figure 1. Growth in Utility CapEx Expenditures, from LBNL and NREL[1]



To gain insight into how the electric distribution companies (EDCs, also referred to broadly as 'the utilities') plan to modernize the distribution system and the cost of doing so, the Commonwealth

[1] "Retail Electricity Price and Cost Trends", Lawrence Berkeley National Laboratory and National Renewable Energy Laboratory, (2024). https://eta-publications.lbl.gov/sites/default/files/2025-01/retail_price_and_cost_trends_2024_update_final_v3.pdf

directed the EDCs to prepare Electric Sector Modernization Plans (ESMPs).[2] As a part of their ESMPs, the EDCs proposed a Grid Services Compensation Fund to support the development of distribution **Grid Services** offerings. These location-specific offerings intend to leverage existing DER capacity – including flexible load – to reduce distribution system infrastructure costs. To help promote Grid Services from concept to practice, the Massachusetts Clean Energy Center (MassCEC), in partnership with the EDCs, the Massachusetts Department of Energy Resources (DOER) and the Attorney General's Office (AGO), contracted Energy and Environmental Economics, Inc. (E3) with support from the Rocky Mountain Institute (RMI) as consulting partners for this study. The study provides frameworks for valuing and compensating Grid Services and recommendations for implementing offerings with consideration for equity and environmental justice.

In this study, we adopt a specific definition of Grid Services: the use of organically deployed (i.e. not deployed specifically for Grid Services participation) DERs to reduce distribution system costs relative to traditional solutions. We identify two scenarios through which DERs could provide valuable Grid Services:

> **Deferral of Infrastructure Investments** can occur if DER dispatch can reliably reduce peak demand on local infrastructure that is slated for upgrade due to load growth. In these scenarios, DERs extend the usability of existing grid assets and maintain reliable service while deferring planned upgrades. Delaying or eliminating the need for infrastructure investment creates value through the financial principle known as the time value of money; a dollar today is worth more than a dollar in the future because a dollar today can be invested and generate earnings over that time. If an EDC can delay or eliminate a capital-intensive infrastructure investment, such as a substation expansion or transformer upgrade, it can achieve financial and ratepayer savings.
>
> **Bridge-to-Wires** opportunities arise where DERs can provide flexible capacity to mitigate local reliability risks for which traditional infrastructure solutions cannot be deployed in time to meet need. In these scenarios, the DERs provide a 'bridge' of temporary relief while more traditional wires solutions are being built. Without DERs, an EDC may be forced to deploy costly interim backup equipment, delay connecting new load to the grid, or allow infrastructure assets to degrade from overuse, thus either incurring costs to replace them sooner or increase the risk of outages. If DERs can sufficiently shift load during peak periods, an EDC can avoid or reduce the need for these tradeoffs.

Neither of these scenarios represent a new concept, but today's circumstances present a new opportunity to mobilize Grid Services. The need for cost reduction is pressing but challenging given the need to accommodate a magnitude of forecasted load growth that has not been seen for decades. In addition, both scenarios further equip utilities with tools for managing uncertain load growth across their service territories. Fortunately, higher-than-ever DER penetrations coupled with

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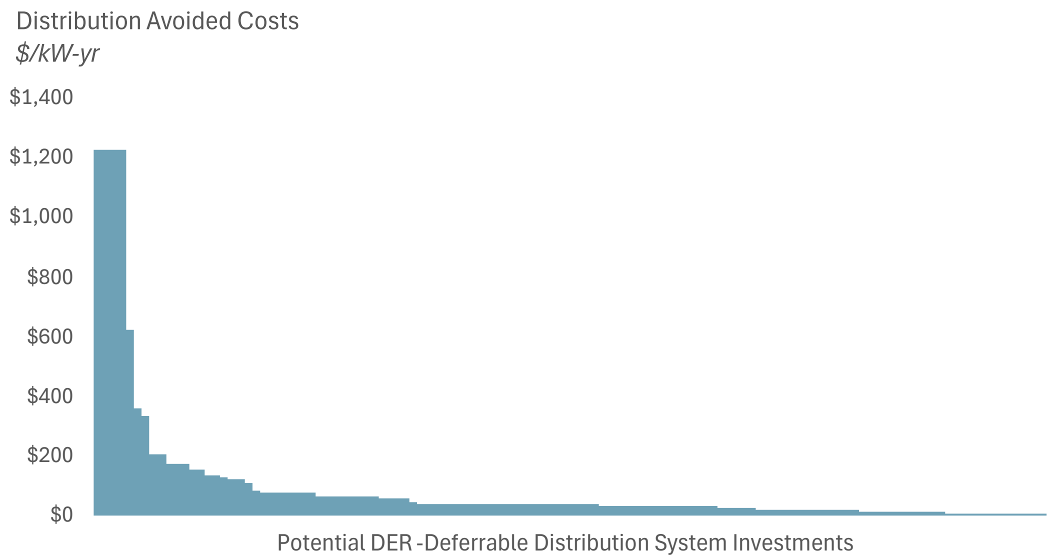
[2] The Massachusetts EDCs include Eversource, National Grid, and Unitil. Within this study, these EDCs are also broadly referred to as the utilities. The EDCs' ESMP filings may be found at: https://www.mass.gov/info-details/electric-sector-modernization-plans-esmps-information-and-recommendations

improvements in grid information granularity and DER-to-grid two-way communications equip grid operators with new resources to meet this challenge in novel ways.

Key Findings

1. **Distribution Grid Services require location-specific mechanisms not available through current programs which focus on bulk system value.**
   Existing compensation programs for DERs focus on value to the bulk (or regional, transmission-level) system. As a result, they allocate compensation to participants on a systemwide basis without regard for where the DER is connected. Systemwide average distribution values inaccurately represent benefits, which may be large in some locations, and near-zero in many others (see the example from California in Figure 2). Grid Services require spatially granular valuation and incentivization to target high value opportunities without wasting ratepayer funds on areas where there is little incremental benefit.

Figure 2. Example Range of Value for Addressing Distribution Grid Needs (from California public utility filings)



2. **Infrastructure deferral by DERs can deliver benefits that create quantifiable savings for customers and harder-to-quantify benefits for impacted communities.**
   The deferral or avoidance of infrastructure investments can offer savings to electric customers as illustrated in Figure 3. If DERs can effectively increase infrastructure capacity and asset utilization, ratepayer savings are generated due to the time value of money, the right-sizing of incremental investment, and the optionality benefit of allowing grid planners to gather additional information before making long-term investment decisions. In the current environment of dynamic load growth, this additional time and information is especially valuable to mitigate forecast uncertainty. Deferral scenarios may also result in benefits which do not affect EDC costs but can be tied to economic and job growth,

construction disturbances, and community ownership of energy resources. We recommend only quantifying the time value of money that arises directly from delayed investment as it is the largest and most certain impact of deferral.

Figure 3. DERs Providing an Investment Deferral Solution

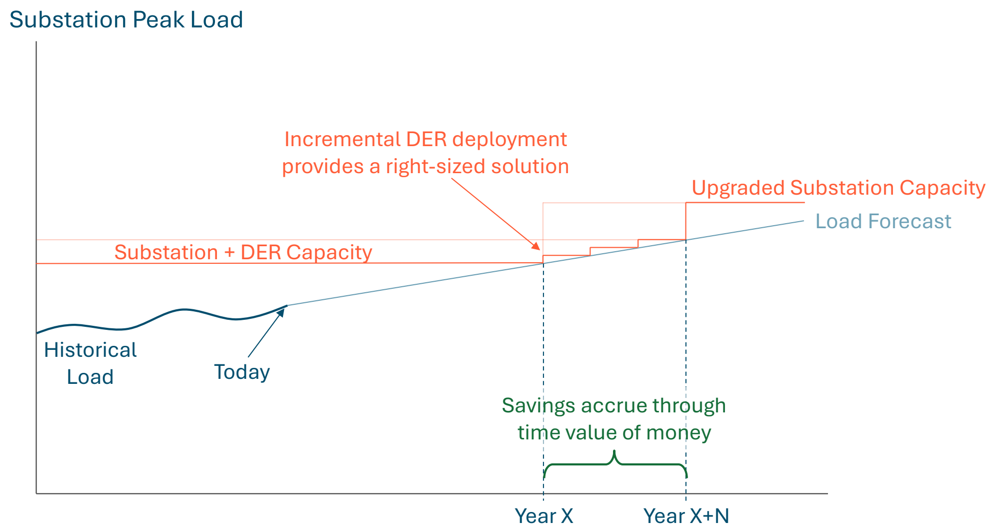
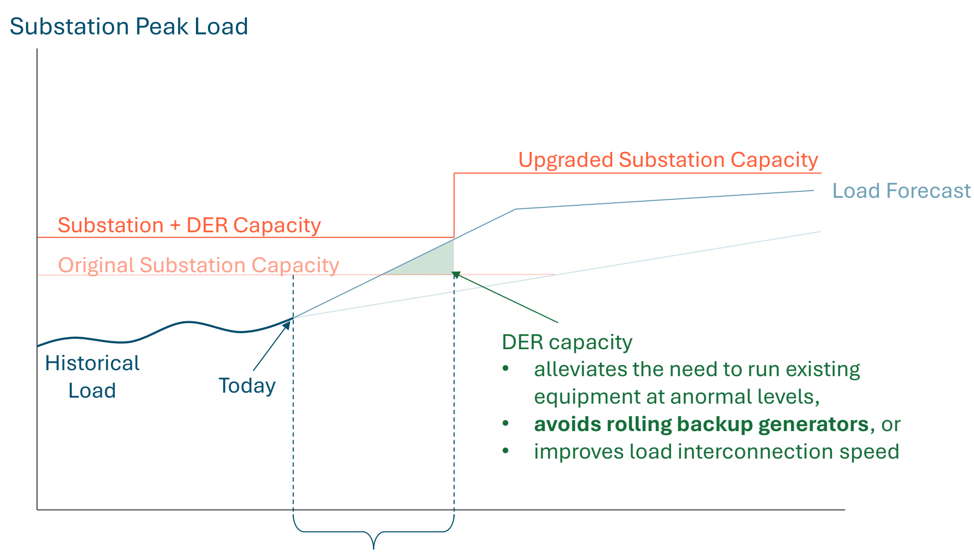


Figure 4. DERs Providing a Bridge-to-Wires Solution



3. **DERs can offer Bridge-to-Wires support where infrastructure upgrades are delayed and there is an immediate need.**

DERs providing Bridge-to-Wires support reduce the need to deploy backup generators, minimize running existing equipment above preferred levels, and facilitate faster-than-anticipated load growth. This scenario is illustrated by Figure 4. We suggest relying on the avoided cost of backup resources as a proxy for the value of Bridge-to-Wires solutions, but we also note the strong dependence of this proxy value on uncertain input assumptions such as the runtime and associated fuel cost of backup generation. Impacts which are not reflected in utility costs include potential effects on reliability and local air emissions. We expect opportunities for Bridge-to-Wires dispatch to be more frequent in the near term due to rapid load growth to taper off, but not vanish, as forecasting/planning processes adjust to this new paradigm.

4. **Benefits provided by DERs in investment deferral and Bridge-to-Wires scenarios should be carefully categorized by their impact on the utility revenue requirement and rates to create a clear understanding of ratepayer impacts.**

Figure 5 shows the different scenarios and value streams associated with Grid Services in our valuation framework, with gray text indicating values that are not recommended for direct consideration in determining compensation. Value streams that reduce the revenue requirement without also reducing sales will translate to lower average rates and ratepayer savings, which can be shared as incentives with participating DERs to promote reliable performance. Non-Rate Impacts are meaningful but do not reduce the revenue requirement or bills, so any inclusion of a Non-Rate Impact in DER incentives has the potential to increase costs for ratepayers.

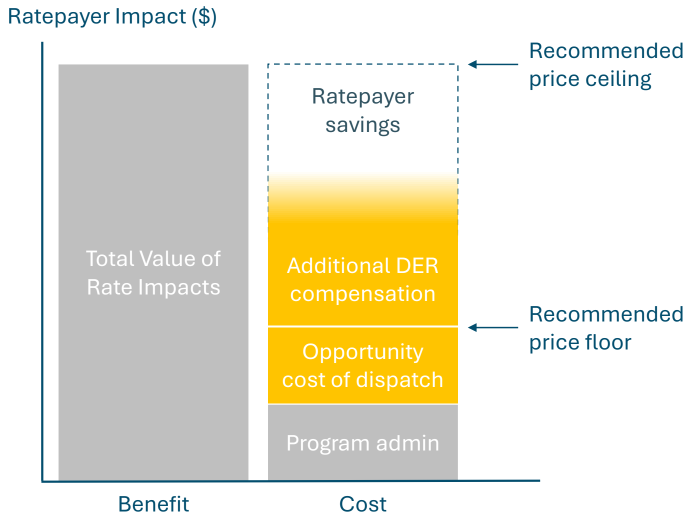
Figure 5. Grid Services Value Streams by Scenario

Capacity Constraint Scenario	Rate Impact Value Stream	Non-Rate Impact Value Stream
Investment Deferral	**Deferral Value** Value of Incremental Investment Optionality	**Environmental Justice Impacts**
Bridge-to-Wires	**Avoided Diesel Backup Generation** OR **Avoided Backup Storage**	**Environmental Justice Impacts** Value of Lost Load Improved Air Quality Avoided Degradation Load Growth Accommodation

5. **To ensure ratepayer savings, compensation for Grid Services should be capped by the net reduction in revenue requirement that the services provide.**

Figure 6 illustrates the relationship between the value of Grid Services in reducing utility costs, the price of utility spending on Grid Services offerings under different compensation levels, and the net value provided to ratepayers. Capping the total compensation to DERs (shown in gold) at the net reduction in revenue requirement ensures no cost to ratepayers. Given that the primary purpose of Grid Services is to reduce ratepayer costs, a goal of the offerings should be to maximize ratepayer savings, while still providing enough of an incentive to DERs to reliably mobilize the needed capacity. Policymakers may choose to supersede this boundary in pursuit of other policy goals but should be aware that doing so can increase rates for non-participants. Environmental justice stakeholders expressed wariness of exceeding a cap by noting that in other programs such cost shifts have resulted in inequitable outcomes.

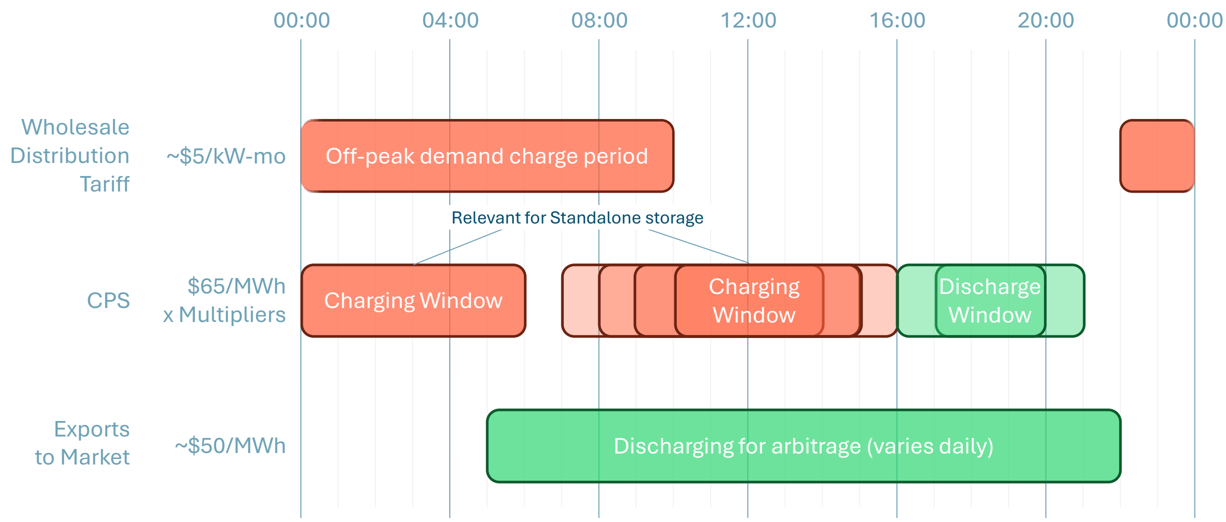
Figure 6. Recommended DER Compensation Floor and Ceiling Values Based on Ratepayer Benefits and Costs from Grid Services



6. **Encouraging DER participation will require that compensation for Grid Services exceed DERs' opportunity cost for forgoing other revenue opportunities.**

Dispatch signals driven by other DER programs, rate design, and wholesale markets may align or conflict with signals for local Grid Services dispatch. As an example, Figure 7 illustrates the components, not including Grid Services, that contribute to a Front-of-the-Meter (FTM) DER's dispatch decision. The opportunity cost of dispatching in response to these other signals forms an effective price floor for Grid Services compensation, which varies by day and hour. In most cases this opportunity cost is weak enough that a modest Grid Services incentive is sufficient to provide incremental participant benefits. When local grid needs and bulk system dispatch align, additional Grid Services incentives may not be required. Where this price floor exceeds the Grid Services value, it is not cost effective to introduce Grid Services offerings.

Figure 7. Existing Dispatch Signals for Front-of-the-Meter DERs



7. **Dispatch signals across all DER programs, including Grid Services offerings, should be coordinated for efficient use of ratepayer funds**.

The existence of an opportunity cost for DER dispatch reveals a market inefficiency. The state and EDCs should develop a plan to adjust existing DER program rules as needed to allow for efficient price signaling. This approach would mitigate the potential inefficient and undesirable scenario where different ratepayer-funded programs (such as SMART, Clean Peak, or ConnectedSolutions) exist in competition with one another and thereby artificially drive compensation upwards. The combined value of dispatch to the entire energy system, incorporating both bulk system needs and localized Grid Services, should dictate the timing of dispatch signals for DERs based on their locations. This points to the larger goal of harmonizing and consolidating programs for bulk and locational grid services to the extent feasible. While eliminating the opportunity costs associated with wholesale energy arbitrage or retail rate design may take longer, this should remain a long-term goal as well.

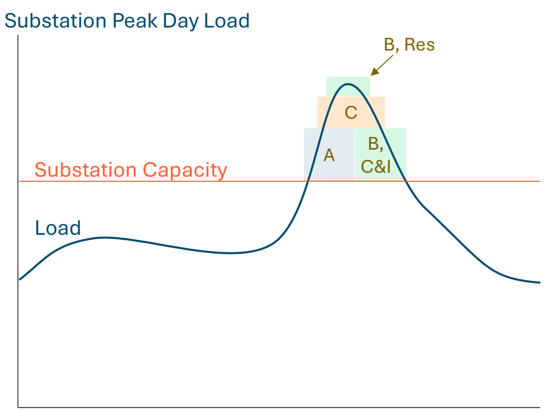
8. **A comprehensive approach is required to support equity and environmental justice in the context of Grid Services offerings.**

In addition to limiting cost shifts and rate increases for non-participants, policymakers and utilities must engage impacted communities early in program development, and during decision making processes. This engagement should meet stakeholders where they are by providing accessible materials and by utilizing trusted community leaders to understand on-the-ground concerns and perspectives and to disseminate information in ways that resonate. Objectives and solutions for Grid Services should then incorporate input shared by these communities. As noted by stakeholders, targeted financial incentives such as EJ-specific adders may comprise one partial solution to allow for increased participation, but it can be a challenge to ensure the incentives make it to the intended recipients. Other barriers to participation, including access to DERs and barriers to DER ownership for those living in rental housing, will require more substantial external funding or creative tailor-made solutions but could be coordinated with Grid Services offerings by targeting specific locations and requiring incentivized equipment to participate in Grid Services programs, where applicable.

9. **Grid Services offerings will be most effective without a one-size-fits-all approach.** While the framework for valuation of Grid Services should be singular, Grid Services offerings themselves should be numerous and varied, such that more DERs owners are able to find offerings in which they are able to participate. As these offerings are trialed, EDC grid operators will gain experience figuring out how to combine them to achieve the desired grid impact. For example, near-term offerings may choose to prioritize simplicity of implementation and testing of compensation levels to understand reliability of dispatch. Subsequent offerings in the longer term may lean into short tenure market-based solutions to improve cost efficiency and planning flexibility. Figure 8 provides a visual demonstration of a suite of offerings that targets different combinations of customer types and technologies stacking together to alleviate a capacity constraint.

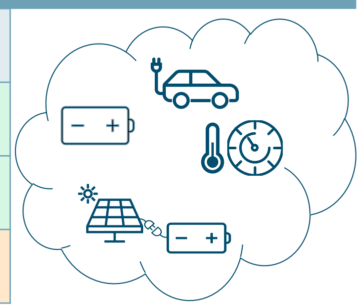
Figure 8. Stacking Grid Services Offerings to Fulfill a Need

Utility Planner's Perspective



Customer's Perspective

Customer/ DER Type	Grid Services Offerings	Potential DER Participants*
Residential	Offering A	
Residential	Offering B	
Commercial & Industrial	Offering B	
Front of the Meter	Offering C	



**Eligible DERs shown are a non-exhaustive sample for illustration only*

10. **The value of Grid Services in the long-term will be maximized by iterative information improvement and "learning by doing" in the near-term.** Identification of opportunities for deferral requires proactive planning that reaches beyond today's practices. The Department of Public Utilities' (DPU's) ruling on the utility ESMPs notes this need, as they "exclude [some substation and feeder] investments from recovery through the interim cost recovery mechanism largely because of [their] determination that legacy distribution system planning practices are outdated".[3] We envision scenario-based policy-compliant distribution level load forecasting as the tool needed for identifying deferral

[3] D.P.U. 24-10-A/D.P.U. 24-11-A/D.P.U. 24-12-A, (2025). https://www.mass.gov/doc/final-esmp-order-82924/download

opportunities at increasingly smaller scales (i.e. below the substation level) in the context of uncertain load growth.

Aside from the planning process, the near term marks a crucial period of "learning by doing". In this early period, grid operators and the state should test program designs with DER owners, invest as needed in new technological capabilities, build relationships with key technology vendors and flexibility service providers, and continue to develop cost recovery frameworks that rely less on capital projects. Trialing Grid Services offerings will provide data on the locations of DERs, their willingness to respond to price signals, the reliability of their response, and how best to conduct customer outreach on Grid Services. Additionally, planners and operators will be learning how to leverage new tools at their disposal including more detailed forecasts, Distributed Energy Resource Management Systems (DERMS), market platform software, improved communications/telemetry, and eventually interval meter data. Evaluation, Measurement and Verification (EM&V) to note the successes and areas for improvement in these early years will provide valuable insight for the Commonwealth and other states embarking on similar journeys.

1. Introduction

Through *An Act Driving Clean Energy and Offshore Wind* enacted in 2022, the Commonwealth of Massachusetts, and subsequently the Department of Public Utilities (DPU), require that each investor-owned electric distribution company (EDC) put forth an electric-sector modernization plan (ESMP) to proactively upgrade their distribution systems.[4] Per the Act, these plans are intended to:

- Improve grid reliability, communications and resiliency
- Enable increased, timely adoption of renewable energy and distributed energy resources
- Promote energy storage and electrification technologies necessary for decarbonization
- Prepare for future climate-driven impacts on the distribution and transmission systems
- Accommodate increased electrification and other potential future demands on distribution and, where applicable, transmission systems
- Minimize or mitigate impacts on Massachusetts ratepayers

These aims also fall under the DPU's broader jurisdiction and mission to promote safety, security, reliability of service, affordability, equity, and greenhouse gas emission reductions.[5] On August 29, 2024 and June 13, 2025, the DPU issued orders approving (with modification) the ESMPs filed by the EDCs and setting parameters for the plans and eligible cost recovery.

Within their ESMPs, the Massachusetts EDCs of Eversource, National Grid, and Unitil each proposed the establishment of a Grid Services Compensation Fund to support and compensate dispatchable DERs (including flexible load) for providing Grid Services.[6] While the EDCs differ in their consideration of Grid Services as a type of Non-Wires Alternative (NWA) or not, they are consistent in how they imagine Grid Services distinctly from traditional NWA solutions. Traditional NWAs seek dedicated solutions procured through competitive bids and selection. Solutions are often large scale and newly built to serve the NWA, though DER aggregators have begun to challenge this assumption. Meanwhile, Grid Services offerings seek to leverage the existing bank of non-specific resources to be deployed as needed, with enrollment occurring through an incentive program or marketplace.

Project partners for this Grid Services Study include the Massachusetts Clean Energy Center (MassCEC), Energy and Environmental Economics (E3), the Rocky Mountain Institute (RMI), the Massachusetts Department of Energy Resources (DOER), the Attorney General's Office of Ratepayer Advocacy (AGO), and the EDCs. MassCEC, in consultation with the DOER, AGO, and EDCs, contracted E3 and RMI to study and provide recommendations to inform the EDC's development of Grid Services offerings. The study identifies methodologies for determining the locational value that

[4] St. 2022, Chapter 179 Section 53 https://malegislature.gov/Laws/SessionLaws/Acts/2022/Chapter179
[5] "Mission Statement", Massachusetts Department of Public Utilities. https://www.mass.gov/orgs/department-of-public-utilities#org-nav-mission
[6] D.P.U. 24-10-A/D.P.U. 24-11-A/D.P.U. 24-12-A, (2025), p.198. https://www.mass.gov/doc/final-esmp-order-82924/download

DERs can provide to the distribution grid and recommends approaches for creating Grid Services offerings as mechanisms to compensate this value. The study also presents a roadmap for the implementation of Grid Services offerings. In both components of the Study—developing valuation methodologies and developing an implementation roadmap—specific consideration is given for building in equity and supporting environmental justice communities (EJCs).

As a part of the study process, between December 2024 and June 2025 the project partners hosted four public workshop sessions, and three environmental justice and equity focus groups. Stakeholder participants in the workshops and focus groups included community and environmental advocates, DER providers, aggregators, and energy-related technology companies, among others. This report and accompanying materials describe and incorporate feedback from these sessions and from stakeholder emails and follow-up surveys. Sections 4 and 5 of this report discuss this feedback in context, and Appendix A. provides a summary of common feedback themes. A comprehensive feedback tracker in spreadsheet format is available on the MassCEC Grid Services Study website to accompany the report.[7]

The Grid Services Study is not intended to calculate and assign specific values for Grid Services. Grid Services value must be assessed based on the individual grid needs that are addressed and will vary by location and timing of the grid need and solution. Rather, this study makes recommendations and seeks to provide transparency into the general methods by which these values may be calculated and ultimately mobilized through Grid Services offerings. Recommendations within this report reflect E3's perspective on these topics and should not be considered as commitments by individual project partners.

The Grid Services Study builds upon a prior "Value of Distributed Energy Resources for Distribution System Grid Services" (Value of DERs) study and report conducted by Baringa Partners on behalf of MassCEC.[8] The Value of DERs work defined several individual frameworks for analysis and compensation structures which are referenced within this Grid Services Study. E3 and the DOER are also conducting a separate Load Management Study in parallel to this study.[9]

Figure 9 highlights some of the key distinctions between the Grid Services Study and the Load Management Study. The Load Management Study provides insight into the supply of grid flexibility by quantifying the technical and feasible potential of DERs responding to drivers that could include existing DER programs, Grid Services offerings, rates, and other signals. This compilation of dispatchable DER potential helps indicate to distribution planners the capacity that might be leveraged for Grid Services, but there is a disconnect in geographic scale: the Load Management Study only describes statewide potential, whereas Grid Services applications require response from

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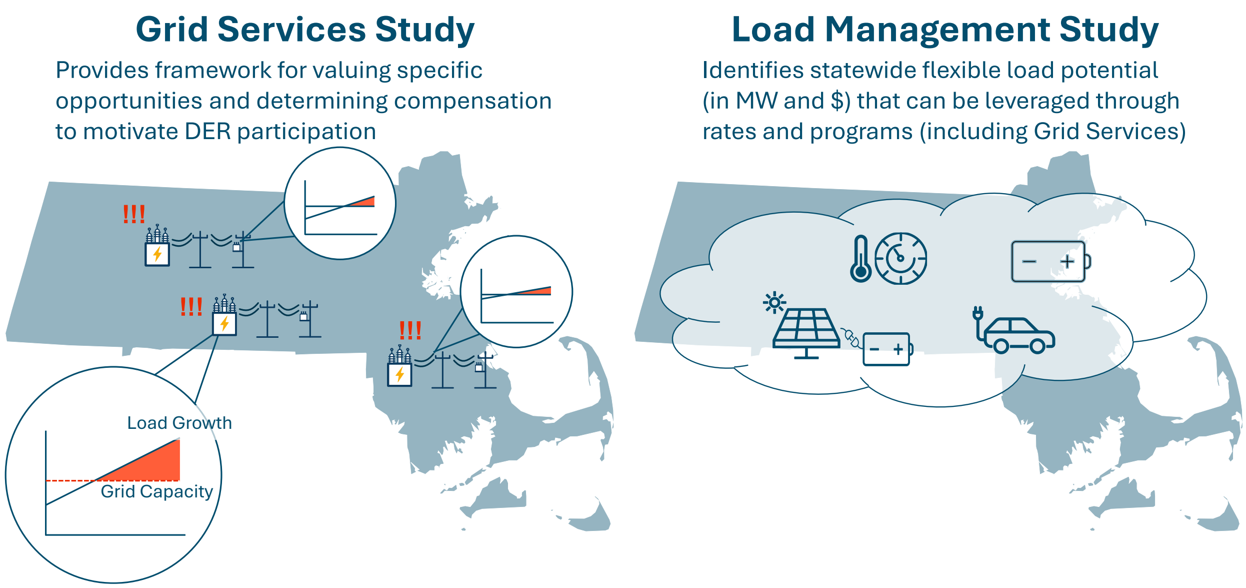
[7] "Grid Services Study", Massachusetts Clean Energy Center. https://www.masscec.com/resources/grid-services-study

[8] "The Value of Distributed Energy Resources for Distribution System Grid Services," Baringa Partners, (2024). https://www.masscec.com/sites/default/files/documents/The%20Value%20of%20Distributed%20Energy%20Resources%20for%20Distribution%20System%20Grid%20Services.pdf

[9] "Peak Potential: Load Management for an Affordable Net-Zero Grid", Massachusetts Department of Energy Resources. https://www.mass.gov/info-details/peak-potential-load-management-for-an-affordable-net-zero-grid

local DER capacity. We imagine that future updates to the Load Management Study could disaggregate statewide results down to a geographic scale that aligns with the needs of Grid Services.

Figure 9. Parallel Grid Services Study and Load Management Study



The remainder of this introduction will describe a vision for Grid Services from multiple perspectives, the landscape of DER programs in Massachusetts, and considerations for environmental justice within this study. The introduction leads into the primary design framework and guiding principles for the study, methods for the evaluation of DER benefits, and recommendations for near- and long-term implementation of Grid Services offerings. This report includes several appendices and is accompanied by two spreadsheet models illustrating the methodologies for valuing Grid Services impacts. Within Appendix B. , readers will find a primer on DERs and Grid Services that was developed for the public stakeholder workshops and which provides includes a glossary and other information tailored to those new to the topics discussed.

1.1. A Vision for Localized Grid Services

As described by the Massachusetts EDCs in the first public workshop for this Grid Services Study,

> "*The EDCs envision a future in which customer flexibility is further integrated into distribution network planning and operations as a complementary lever to physical distribution investments, maximizing the value of customer flexibility to reduce the costs of the clean energy transition.*"[10]

This vision imagines distribution system operators (the EDCs) using DERs enrolled in Grid Services offerings as a tool to manage local constraints, cost-effectively improve system efficiency and reliability, and reduce the cost of network investments through deferral and avoidance of

[10] Grid Services Study Stakeholder Workshop 1, December 2024.

infrastructure.[11] In proposing this Grid Services Study, the project partners also proposed provisions for the added value of DERs in EJCs.[12] This vision is shaped by the DPU Order guiding the ESMPs,[13] and supports the DPU's mission to provide reliability and affordable and equitable approaches to reducing greenhouse gas (GHG) emissions.

In public workshops and focus groups for this study, stakeholders volunteered further perspectives on visions for Grid Services. These visions include offerings that challenge traditional roles and address historic injustices in the energy system, support community ownership of energy resources, make DERs more affordable through additional value and revenue streams, and promote overall electricity affordability. These concepts, along with other suggestions provided by stakeholders, offer insight into the aspects that resonate most deeply with stakeholders and shape our definition of successful Grid Services offerings.

Integrating these different perspectives, we arrived at five core aspects of the vision for Grid Services. Grid Services should:

1. **Incorporate the full achievable potential of DERs in utility planning to optimize grid investments and reduce costs for ratepayers**
2. **Integrate DER dispatch calls into distribution system operator practices to provide real-time system relief during stress events**
3. **Enable and accelerate electrification by alleviating local constraints**
4. **Reduce the need for other financially and/or environmentally costly short-term solutions**
5. **Ensure equitable distribution of Grid Services benefits by providing direct benefits to EJCs, including compensation to support environmental justice (EJ) ownership of DERs**

As Grid Services offerings seek to fulfill these roles and respond to the needs of an evolving distribution grid, they also fill a gap among the many programs available to DERs in Massachusetts today. Where existing programs seek to decarbonize and manage grid needs at a bulk-system level—addressing challenges that are common across the shared generation and transmission system—Grid Services offerings will address needs at the local distribution level. These offerings will support infrastructure that might serve an individual neighborhood or community. Because Grid Services address specific points or assets on the system, the value that DERs can provide is similarly precise.

[11] "Electric Sector Modernization Plan", Eversource, (2024), p. 332. https://www.eversource.com/content/docs/default-source/default-document-library/eversource-esmp%20.pdf; "Future Grid Plan", National Grid, (2024), p. 266. https://www.nationalgridus.com/media/pdfs/our-company/massachusetts-grid-modernization/future-grid-full-plan.pdf

[12] "Electric Sector Modernization Plan", Unitil, (2024), p. 125. https://unitil.com/sites/default/files/2024-01/Unitil-ESMP-2025-2050-DPU-FINAL.pdf

[13] D.P.U. 24-10-A/D.P.U. 24-11-A/D.P.U. 24-12-A, (2025). https://www.mass.gov/doc/final-esmp-order-82924/download

Figure 10. The Electricity Grid and Distribution System Needs

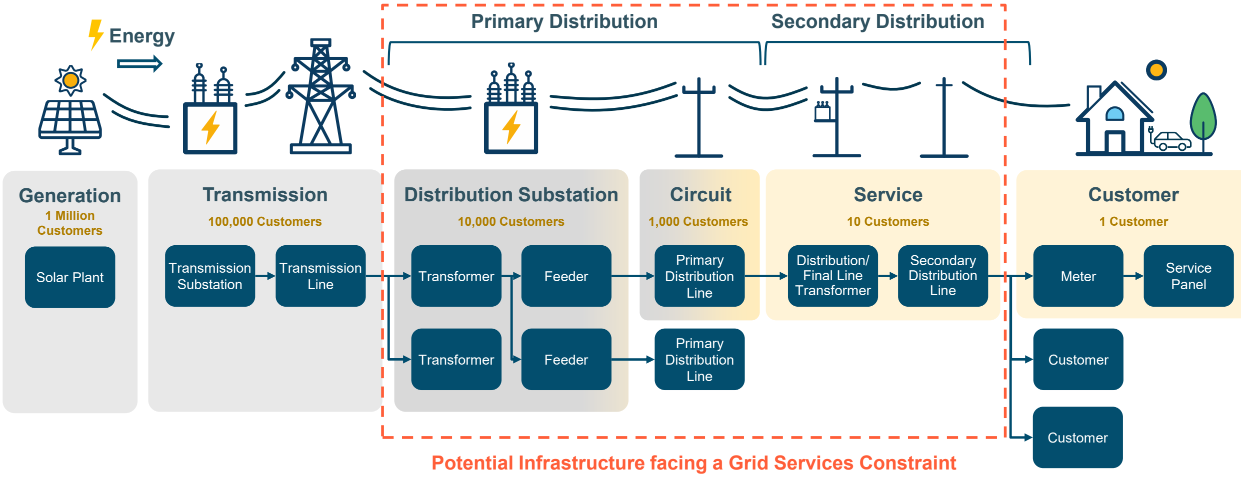


Figure 10 illustrates the flow of energy from upstream utility-scale generation sources through the transmission and distribution infrastructure and on to end consumers. As energy flows from left to right in the diagram, the grid infrastructure branches into progressively smaller pathways, so that downstream each piece of equipment serves fewer consumers. Grid Services offerings are intended to address needs that arise at this more granular level, shown by the dashed red outline. For example, if a distribution final line transformer is forecasted to be overloaded, the action to avoid an overload must occur downstream of the transformer. Given the local nature of the distribution grid, stakeholders highlighted that community involvement can be particularly meaningful because distribution system needs are shaped by the timing of local demands and can only be served by resources local to the need as an alternative to infrastructure upgrades.

The evaluation of DER impacts at a local level is a new frontier for most jurisdictions. Historically, programs that compensate distribution Grid Services have estimated systemwide average values, paying the same amount to all DERs, regardless of location. This approach can work well for programs that focus on bulk system benefits but is less effective for addressing localized distribution system needs. Using systemwide average values for distribution Grid Services can result in ratepayer funds being spent in some areas where there is little incremental distribution benefit and failing to sufficiently incentivize DERs in areas where they could be providing value. New York and California have begun to offer or investigate location-specific compensation for DERs, though the effort requires more granular planning and improved visibility into grid needs and customer and DER behaviors.[14]

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[14] New York's Value Stack for DERs includes a Locational System Relief Value component available to projects offering relief in specific priority zones. "Value Stack Resources", NYSERDA. https://www.nyserda.ny.gov/All-Programs/NY-Sun/Contractors/Value-of-Distributed-Energy-Resources/Value-Stack-Resources; California is in the early stages of evaluating location-specific values for the distribution component of the Avoided Cost Calculator. Heleno, M., Li, Y., Moreira, A., Deason, J., "Avoided Distribution Cost Study Research Plan", Berkeley Lab, (2025). https://pda.energydataweb.com/api/view/4184/LBNL%20Draft%20Research%20Plan.pdf

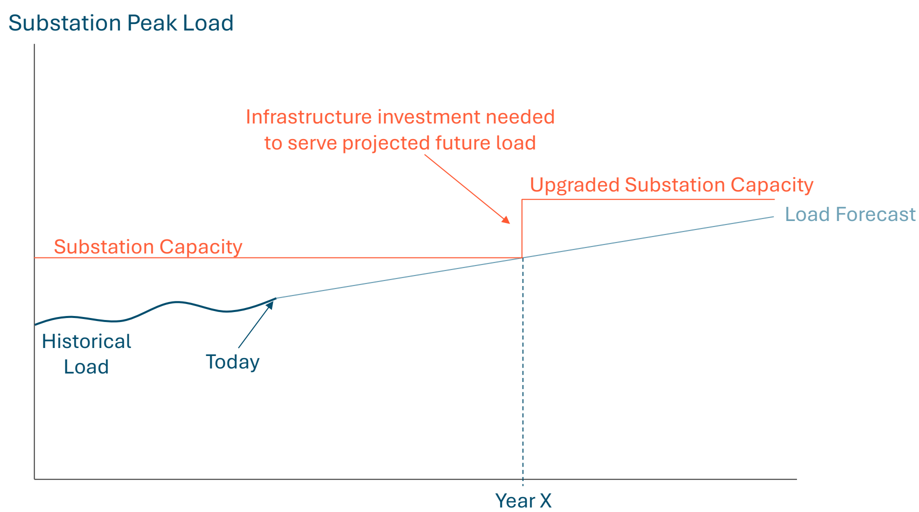
Grid modernization efforts and new technologies provide opportunities to supplement systemwide programs with approaches to manage more local constraints. Evolving systems and software help grid operators to detect or predict where new loads and DERs will materialize. This level of granularity can also be valuable in making sure that compensation goes to the right place at the right time, providing appropriate signals to DERs. In the immediate future this can help DERs optimize their dispatch to meet local needs; in the longer term it can encourage the siting of DERs where they will provide the most benefit.

Acknowledging that this Grid Services vision will require a concerted effort and the development of new capabilities, we propose a phased approach, beginning with this study and then transitioning Grid Services offerings development to the EDCs with a series of recommended near-term objectives and then longer-term considerations. The near-term objectives are poised to cover implementation over the next five years as the EDCs test approaches, learn from them, and scale the offerings, while sharing findings and best practices among themselves and with the public through biannual ESMP reports. The longer-term considerations should also be kept in mind, but especially address standing up sustainable and adaptable offerings for the EDCs' 2029 ESMP plan updates and beyond.

1.2. Grid Services to Relieve Local Capacity Constraint Scenarios

When we imagine Grid Services, we consider two types of local capacity constraints that could be relieved by DER dispatch: (1) Deferral of Infrastructure Investments and (2) Bridge-to-Wires Solutions. Opportunities for these applications result from the risk of load downstream of distribution infrastructure exceeding the infrastructure's rated capacity. Figure 11 offers a simple depiction of this situation for a substation that is forecast to become undersized in a future year, year X. To avoid this shortfall, traditionally an upgrade to increase substation capacity is planned for completion by year X. However, DERs offer the potential to relieve the capacity constraint, providing a critical grid service.

Figure 11. Forecast Need for Distribution Infrastructure Investment

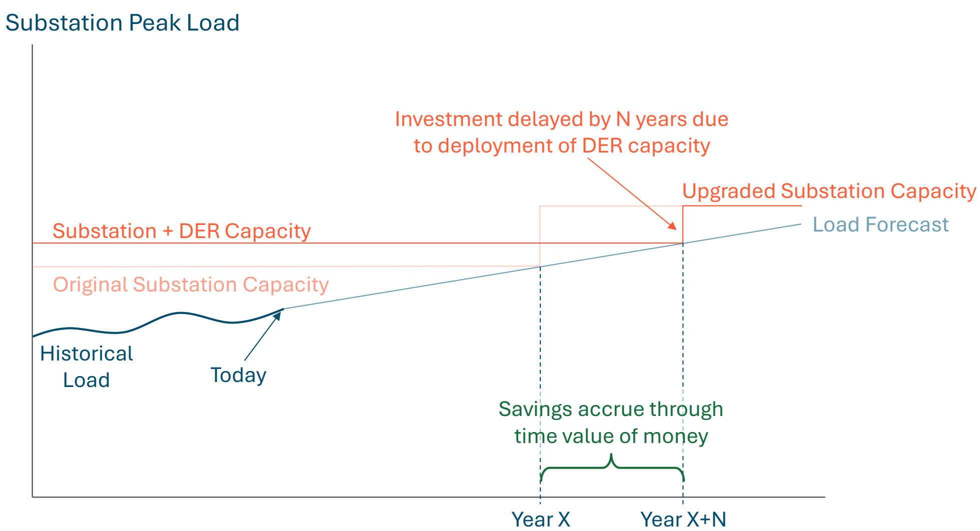


1.2.1. Deferral of Infrastructure Investments

DERs have the potential to reduce or shift load to times of day when local infrastructure is not constrained, thereby preventing capacity shortfalls. By dispatching sufficient DER capacity, EDCs can extend the life of existing infrastructure and defer costly upgrades, creating distribution grid benefits and cost savings.

Figure 12 builds on the example capacity constraint presented in Figure 11, but provides an alternate solution to near-term infrastructure build-out. In this scenario, DERs enrolled to provide Grid Services dispatch to reduce the local peak below the existing substation capacity in year X. While the DERs enrolled continue to provide enough capacity to counter local peak load growth, the new infrastructure investment can be delayed. In this example, the infrastructure investment is delayed by N years due to DER dispatch. As we discuss in Section 3.1.1, this delay of capital expense by N years creates both monetized and qualitative value for the ratepayers and the state.

Figure 12. DERs Providing Deferral of an Infrastructure Investment



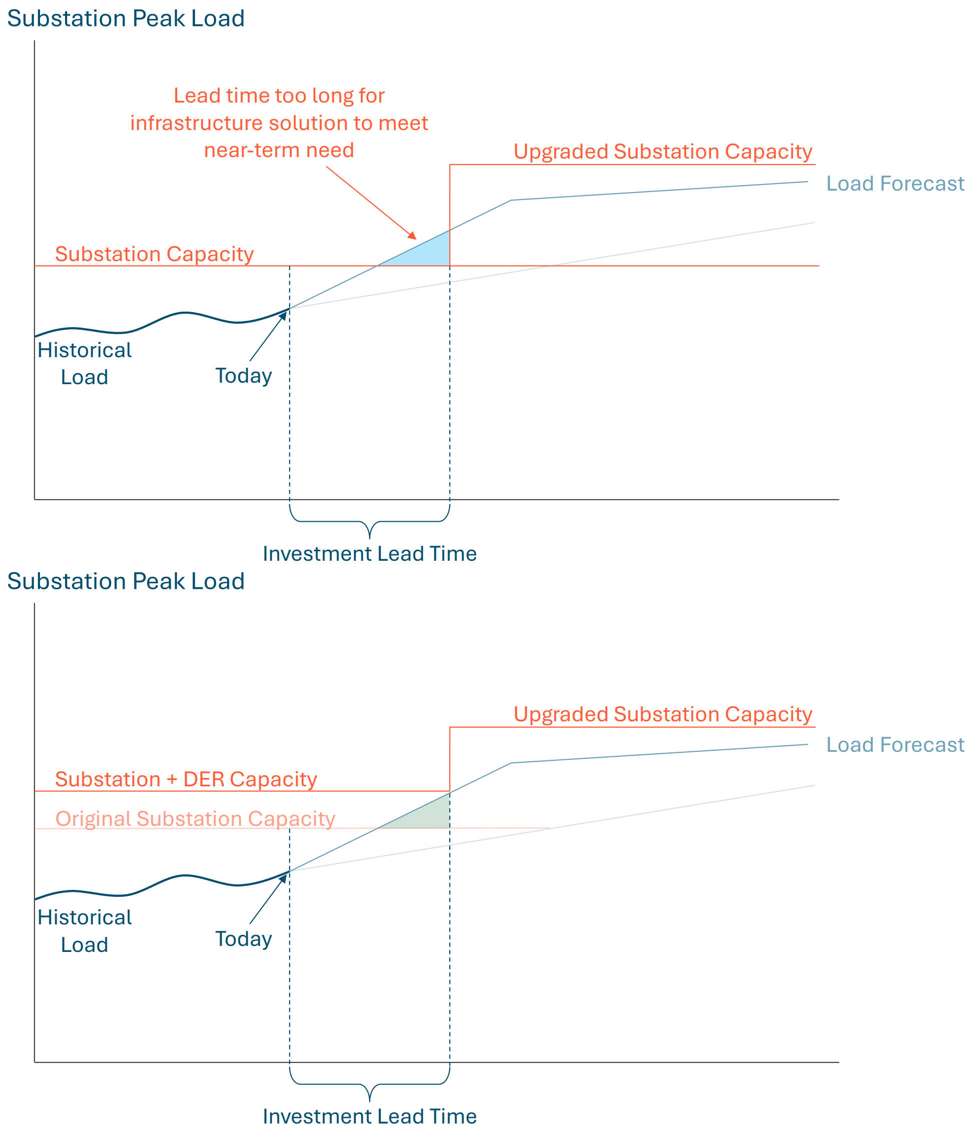
Generally, longer deferment of an investment through utilization of DERs translates to more value, but this principle has its limits. For example, an asset reaching the end of its useful life will have limited or no opportunity for upgrade deferral. Also, deferral is limited by the volume of DERs that can be enrolled to meet the distribution capacity shortfall. In areas where DER penetration is low, investment deferral may not be possible. As DER penetration increases, the number of opportunities and total potential value for deferral is expected to increase in turn.

1.2.2. DERs as a Bridge-to-Wires Solution

Another scenario where DERs can provide a localized distribution benefit occurs when an EDC identifies an imminent distribution capacity shortfall but cannot implement a traditional infrastructure upgrade before the shortfall is expected to arise. The top panel of Figure 13 introduces this challenge by noting the investment lead time necessary to plan and execute a project such as a substation capacity upgrade. In this example, even if permitting and construction for the new infrastructure were to begin today, the upgraded infrastructure would not be available until after it is first needed.

As indicated by the bottom panel of the figure, DERs dispatched for Grid Services could bridge the gap—by dispatching DERs during critical periods of peak demand, grid operators may be able to address the shortfall until new capacity is online. This DER “bridge” to increased infrastructure capacity avoids less desirable outcomes, which might include deployment of costly interim backup equipment, delays in connecting new load to the grid, or allowing infrastructure assets to degrade due to consistent operation above standard operational levels. Section 3.1.4 discusses how we can assess the value of this bridge through some of these avoided outcomes.

Figure 13. Bridge-to-Wires Need and DER Solution



Opportunities for DERs to provide Bridge-to-Wires solutions are becoming increasingly common as the grid enters an era of rapid load growth after two decades of negligible change. Large increases in load are expected from policy-supported electrification of transportation and buildings, but there is high uncertainty around the timing and location of those changes. These, combined with generally uncertain development of new large-scale loads, such as from data centers, threaten to create the need for widespread upgrades that will compound already stressed infrastructure development timelines. Traditional reactive approaches to distribution planning are evolving to be more proactive but do not consistently anticipate the specific timing and location of these needs. As distribution planners implement new forecasting practices and gain further experience with these trends, this should alleviate the needs for many, but not all, Bridge-to-Wires applications.

1.3. The Landscape of Existing DER Programs

Enrollment and dispatch of DERs to provide Grid Services will exist within a larger landscape of DER incentive programs in Massachusetts. The Commonwealth has four principal incentive programs in place that are available to broad subsets of DERs: ConnectedSolutions, the Clean Peak Energy Standard, the Solar Massachusetts Renewable Target, and Net Metering. Aggregations of DERs may also directly participate in wholesale markets as directed by FERC Order No. 2222 to be compensated for the energy and capacity they provide depending on where they connect to the grid.[15]

In contrast to the location-specific nature of Grid Services, each of these existing programs seeks to manage grid needs and promote decarbonization at the bulk-system level. Collectively, these programs already compensate DERs for several categories of benefits, including energy, generation capacity, transmission capacity, and GHG emission reductions. To avoid redundancy and over-compensating DERs for these bulk-system benefits, Grid Services offerings should focus only on the locational distribution system benefits that are not explicitly valued in other DER programs. Where silos separate these programs today, EDCs and regulators should look for synergistic opportunities across programs that might reduce administrative expenses and send more efficient price signals to participants.

Mass Save ConnectedSolutions

The ConnectedSolutions (CS) program[16] aims to reduce peak energy use by incentivizing behind-the-meter (BTM) demand response through energy storage discharge, smart thermostat control, and usage curtailment. During peak events—typically a few hours in summer afternoons or evenings—customers receive a signal to curtail usage or discharge energy to the grid and are paid either a flat per-season incentive or a per-kWh incentive based on their average performance over a season.

[15] "Order No. 2222 Key Project", ISO New England. https://www.iso-ne.com/committees/key-projects/order-no-2222-key-project

[16] "ConnectedSolutions", Mass Save. https://www.masssave.com/residential/programs-and-services/connectedsolutions

Clean Peak Energy Standard

Established by DOER, Massachusetts's Clean Peak Energy Standard[17] promotes the use of clean energy to meet demand during peak periods—typically 4-hour evening windows—which would otherwise be met with GHG emitting resources. The Clean Peak Standard compensates clean generation technologies that operate during peak periods, demand-reducing resources that reduce peak load, and storage technologies that shift clean energy into peak periods.

The Clean Peak Energy Standard includes a Distribution Circuit Multiplier. This multiplier doubles the incentive for the first 10 years to eligible Clean Peak resources sited on circuits pre-identified as having limited capacity. The multiplier represents a less precise attempt to compensate DERs for local Grid Services, and the multiplier should be phased out as Grid Services offerings become robust. Otherwise, a DER receiving the Distribution Circuit Multiplier and Grid Services compensation would be paid twice for the same benefit.

SMART

The Solar Massachusetts Renewable Target Program (SMART)[18] is an incentive program where solar system owners receive a fixed payment per kWh of energy produced.[19] The program is primarily a BTM solar incentive program, but it includes adders to the fixed payment for pairing with energy storage. SMART's energy storage incentive focuses on supporting the buildout of solar plus storage projects, leaving the incentivization of preferred dispatch behavior to other programs.

Net Energy Metering

Net Energy Metering (NEM)[20] allows distributed energy resources, such as rooftop solar, to earn credits for excess electricity exported to the grid, effectively offsetting the customer's electricity consumption on their retail bill. NEM credits are calculated based on DER generation exported to the grid at any time or location. While NEM compensation incentivizes DER adoption, it doesn't account for the location of the DERs on the distribution system, or of the timing of energy exports relative to local distribution needs.

1.4. Environmental Justice and Equity Considerations

The current evolution of the electric grid provides an opportunity to also ensure the prioritization of equity and environmental justice in both process and outcomes. In developing recommendations

[17] "Clean Peak Energy Standard", Massachusetts DOER. https://www.mass.gov/clean-peak-energy-standard
[18] "Solar Massachusetts Renewable Target (SMART)", Massachusetts DOER. https://www.mass.gov/solar-massachusetts-renewable-target-smart
[19] Formerly under a declining block incentive structure, DOER changed the SMART program structure in June 2025 to annually update the incentive levels for generation units and the available capacity eligible to receive an incentive for a given program year. "Smart 3.0 Program Details", Massachusetts Department of Energy Resources. https://www.mass.gov/info-details/smart-30-program-details
[20] "Net Metering", Massachusetts DPU. https://www.mass.gov/net-metering

for Grid Services, this study explores how Grid Services offerings may advance equity and environmental justice.

As described by the Massachusetts Office of Environmental Justice and Equity, "Environmental justice is based on the principle that all people have a right to be protected from environmental hazards and to live in and enjoy a clean and healthful environment. Environmental justice is the equal protection and meaningful involvement of all people with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies and the equitable distribution of environmental benefits."[21] For the purposes of the Grid Services Study, environmental justice community subsequently refers to communities which have been marginalized on the basis of race, culture, ethnicity, or socioeconomic status or have borne disproportional environmental burdens.[22] In the energy sector, environmental justice focuses on how energy systems contribute to pollution and climate change—and how those impacts, along with access to clean energy, are distributed across communities.

Our approach to incorporating feedback and recommendations related to environmental justice is guided by three core facets:

Recognition Justice – Recognition of historical context, systemic injustices, and differences between communities

Procedural Justice – Meaningful involvement of impacted communities in decision making processes

Distributive Justice – Equitable distribution of both benefits and burdens

We provide recommendations in this report designed to align Grid Services with each of these facets. Some examples are as follows: Recognition justice provides historical context that guides recommendations to address prior failings of design and implementation. We recognize the tenets of procedural justice during the course of this Grid Services study, adapting the study engagement and materials based on input from EJ and community stakeholders. Recommendations in Sections 4 and 5 of this report are designed to further advance procedural justice in how the Commonwealth and EDCs involve communities and other stakeholders in the development and evolution of offerings over time. Many of the recommendations in this report are designed to advance distributive justice:

- Section 2 discusses how Grid Services can be used to alleviate existing energy burdens and guide a more equitable allocation of benefits from Grid Services offerings.
- Section 3 proposes methodologies for valuing Grid Services impacts that can factor into environmental justice-focused compensation adders.
- Section 4 provides further recommendations for addressing barriers to participation for EJCs.

[21] "Objectives of Environmental Justice", Massachusetts OEJE. https://www.mass.gov/info-details/objectives-of-environmental-justice

[22] This definition is distinct from the Massachusetts definition for Environmental Justice Populations, which classifies communities based on median income, race, and English language proficiency. "Environmental Justice Populations in Massachusetts", Massachusetts OEJE. https://www.mass.gov/info-details/environmental-justice-populations-in-massachusetts

We recognize the limits of the impact that Grid Services offerings can have on energy equity. While the design of Grid Services offerings should reduce burdens on EJCs and improve equitable access to Grid Services benefits, additional policies and programs—beyond the scope of this study—are needed. These parallel efforts are essential to prevent overburdening EJ communities, protect them from continuing to shoulder disproportionate energy-related costs, and ensure direct access to benefits. These include rate reform, affordability program design, access to DER programs designed to subsidize adoption, engagement and knowledge building around energy and DERs, concentrated efforts to avoid stranded energy system costs, and others.

2. Designing a Framework for Grid Services Offerings

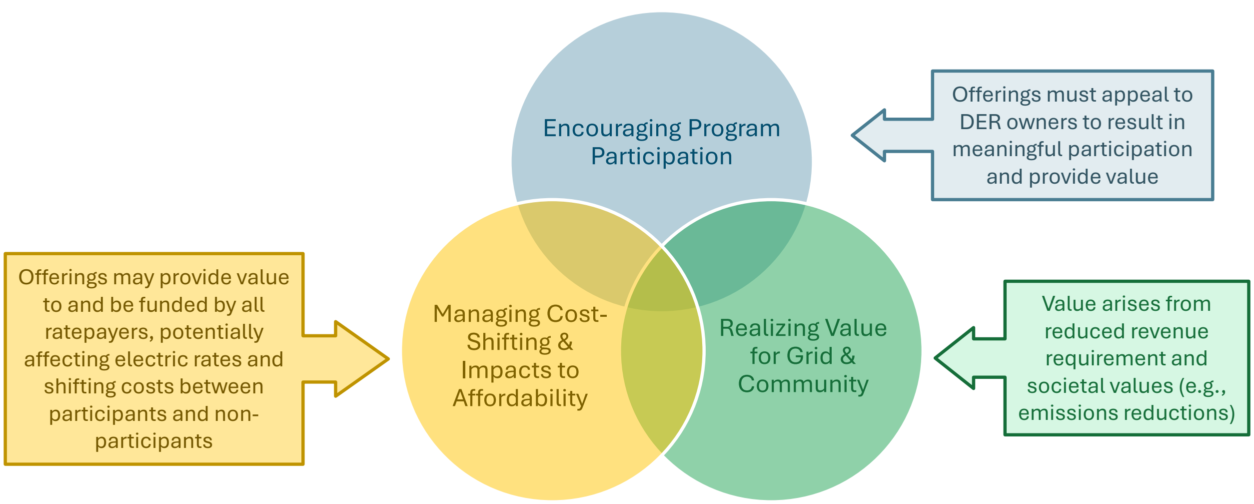
Developing the ways to compensate DER owners for Grid Services support begins with consideration of the five-point vision described in Section 1.1. We aim to create a framework that guides the design of compensation ("compensation framework") facilitates Grid Services offerings achieving this vision.

This section describes the competing policy goals which must be balanced in designing a DER compensation framework and highlights two key compensation framework recommendations that push towards the vision for localized Grid Services while maintaining balance among policy goals. The application of this framework is described further in Section 4.

2.1. Balancing Framework Design Goals

Utility-sponsored DER compensation mechanisms may further a variety of different policies but ultimately must balance the competing and intertwined goals shown in Figure 14: encouraging program participation, managing cost shifts and impacts to affordability, and realizing value for the grid and community.

Figure 14. Competing Goals for Framework Design



Encouraging Program Participation: For Grid Services offerings to have a meaningful impact, they must attract customer participation. Participation relies on providing incentives of a sufficient magnitude and in the right format to appeal to DER owners and elicit the desired load shift response. Compensation may be set at the bare minimum to make participation economically feasible for existing DER owners, or more favorable incentive levels can help maximize enrollment and encourage incremental adoption of DERs. Prioritization among this spectrum may shift as offerings mature, requiring a higher incentive to spur initial adoption and a lesser incentive as the market saturates.

Non-monetary aspects of offerings can also support participation. Given the location-specific nature of Grid Services offerings, targeted community outreach will be especially important, and simple and transparent processes for enrolling participants and administering incentives can also support participation. These non-monetary design components can reduce the need for higher incentives and support the other design goals, but require upfront investment and focus.

Managing Cost Shifts and Impacts to Affordability – Cost shifts can occur if ratepayers pay more to support a DER compensation offering than the monetized value the offering provides for ratepayers. In other words, if the total cost of an offering, including compensation and all other costs to establish and administer the offering, is higher than the savings generated by the offering, this will lead to upward pressure on electric rates and negatively impact energy affordability. It is considered a cost *shift* because it also results in costs being transferred from individuals who are able to participate in the offering to non-participating ratepayers. While all ratepayers end up paying to fund incentive offerings, participants receive those incentives to save them money, whereas non-participants only experience higher bills. To the extent that low-income and environmental justice communities face barriers to participating in offerings (as will be discussed in Section 4.3), they will also face disproportionate harm from any resulting cost shift. While cost shifts are ideally avoided, in some instances cost shifts may be deemed acceptable when weighed against other policy goals. In those cases, it is important to manage the degree and direction of cost shifts. Managing cost shifting requires understanding the incremental benefits that an offering provides and all the costs that must be weighed against those benefits. Measuring incrementality of an offering is crucial to ensure that multiple programs do not double-pay for specific benefits.

Realizing Value for the Grid and Community – Incentive programs are intended to deliver value to ratepayers or society in addition to delivering value to participating customers. This value comes in many forms, including several impacts which are directly monetized through rates as well as impacts with less explicit monetization which can nonetheless provide real benefit to local communities or society. Values relevant to Grid Services offerings are described in Section 3. For many of these value streams, price signals indicating when or where DERs should be dispatched are critical for maximizing this value.

The weight given to each of the goals in Figure 14 may vary for different offerings or at different stages of implementation, but all three must be considered for Grid Services offerings to be sustainable and provide material benefits. We note that our consideration of cost shifting is limited to the location-specific values which are tied to distribution system investment. We do not consider the cost shift across other DER value streams such as those tied to bulk grid value.

2.2. Generating Ratepayer Savings

Multiple points of the vision for Grid Services follow the theme of cost reduction that is also represented in the framework design goals. Based on this alignment, one compensation framework recommendation is to design compensation to generate ratepayer savings

By designing compensation such that it generates ratepayer savings, Grid Services offerings can bridge the goals of realizing value for the grid and community and of managing cost shifts and affordability. In pursuit of these goals, we recommend that the valuation of rate-related impacts from DERs serves as the primary basis for establishing Grid Services compensation and that ultimately some value be preserved for ratepayers. This can be accomplished by ensuring that the total cost of Grid Services offerings is lower than the rate-related value that Grid Services provide.

DERs and Grid Services can put downward pressure on customer rates by reducing the revenue requirement. The revenue requirement represents the total cost of system investments which EDCs recover through customer electric rates. We are therefore able to value the rate impacts of Grid Services by how they affect these system costs. Methodologies for doing so are described in Section 3.1 of this report. To generate ratepayer savings, compensation plus all other costs of administering an offering must be less than the value of rate-related impacts.

DER adoption may also accrue benefits or costs to society which do not directly result in savings via rates, and we refer to these as non-rate impacts. Non-rate impacts, described in Section 3.2, also merit recognition, but to the extent that they are included in ratepayer-funded Grid Services compensation, they may put upward pressure on rates. To avoid increasing rates, compensation for and administration of Grid Services offerings must not exceed the rate-related impacts. Beneficial non-rate impacts may instead be compensated through separate funding sources that are not tied to electric rates, such as taxes, voluntary incentive pools, or markets funded by beneficiaries of these non-rate impacts. Further exploration of these mechanisms is beyond the purview of this study.

In specific instances, Massachusetts regulators and/or policymakers may choose to prioritize other policy objectives over ratepayer savings and authorize compensation higher than rate-related savings. Relevant policy objectives could include jumpstarting DER flexibility market development or providing additional participation or DER adoption incentives for EJCs and low-income customers. However, such decisions should be carefully considered and avoid unintended impacts. For instance, with an incentives designed to increase equity in adoption or participation there may be limited control over how much of the incentives reach the intended recipients. Ratepayer savings, in contrast, represent concrete benefits regardless of who participates in Grid Services offerings. In the long term, Grid Services offerings should be designed to reduce the revenue requirement.

2.3. Improving Environmental Justice Within the Scope of Distribution Grid Services

A second important compensation framework recommendation is to ensure that compensation offerings ameliorate, rather than exacerbate, environmental justice concerns around affordability, community value, and participation in Grid Services.

Creating a more just and equitable future for the electric grid requires recognizing inequities in current systems and rebuilding them, informed by impacted communities. A framework for Grid Services should ensure that offerings do not worsen existing environmental justice burdens and should support mechanisms to improve equity. Community representatives who participated in this study's EJ focus groups highlighted several key concerns for the Grid Services Study and future offerings to address. Two of these concerns are: 1) how DER programs are financed by ratepayers, specifically, that Grid Services offerings protect against disproportionate program costs being borne by ratepayers that are unable to access the benefits, and 2) and how compensation can be best tailored to advance equity for EJCs, such as by considering the non-rate impacts of DERs when located in EJCs.

The first of these concerns would be addressed in part by ensuring that Grid Services generate ratepayer savings. A compensation design which reduces the revenue requirement will prevent non-participants from bearing any additional costs from Grid Services offerings. However, the issue of ensuring equitable access to the benefits is dependent on first having equitable access to owning DERs. This issue goes beyond the direct scope of Grid Services alone. Compensating EJCs with additional value from Grid Services will not fully address barriers such as the upfront cost of DERs. Regardless, we recommend increasing access to the benefits of Grid Services offerings for EJCs through a percentage-based environmental justice adder for qualified participants and an air quality impact-based adder for certain projects sited in EJCs.[23] These approaches are described in more detail in Section 3. Both adders serve to increase compensation, which can serve to reduce the payback period for EJC investments in DERs. Recognizing that many other barriers to adoption exist, we provide further recommendations around community engagement and improving access in the implementation sections of this report.

[23] For practical purposes in near-term implementation, these EJC locations may align with the Commonwealth's designated Environmental Justice Populations. "Environmental Justice Populations in Massachusetts", Massachusetts OEJE. https://www.mass.gov/info-details/environmental-justice-populations-in-massachusetts. However, in the long term, E3 recommends designating EJC areas based on a more holistic determination which also considers local air quality or other environmental conditions.

3. Evaluation of DER Benefits

To compensate DERs for the value they provide to the grid, a consistent process is needed to determine that value. This Grid Services Study focuses on the location-specific benefits that DERs provide to the distribution system. The study excludes broader, bulk grid benefits such as avoided energy, generation capacity, and transmission capacity costs or GHG reductions. As described in Section 1.3, these benefits are meaningful but are compensated through other programs in Massachusetts.

As described in Section 1.2, we assess the localized benefits DERs provide to the distribution grid under two scenarios: Deferral of Infrastructure Investments and Bridge-to-Wires Solutions. Figure 15 shows the value streams that we consider, grouped by the associated Grid Services scenario. Rate Impact Value Streams are those that affect an EDC's revenue requirement and rates, therefore resulting in a cost impact for ratepayers. Value streams listed under Non-Rate Impacts do not change the EDC revenue requirement but may have quantified or qualifiable impacts on participants or broader society. The grayed-out value streams are not currently recommended for direct inclusion in determining compensation.

Figure 15. Grid Services Value Streams by Scenario

Capacity Constraint Scenario	Rate Impact Value Stream	Non-Rate Impact Value Stream
Investment Deferral	**Deferral Value** Value of Incremental Investment Optionality	**Environmental Justice Impacts**
Bridge-to-Wires	**Avoided Diesel Backup Generation** OR **Avoided Backup Storage**	**Environmental Justice Impacts** Value of Lost Load Improved Air Quality Avoided Degradation Load Growth Accommodation

The following sections discuss these value streams and, where appropriate, provide examples of how they can be calculated.

3.1. Rate Impacts of DER Grid Services

Rate impacts refer to the effect on an EDC's revenue requirement—the total costs an EDC must recover from its customers through rates – without commensurate impacts on sales. When DERs reduce the need for capital investment or operational expenses, they can lower the total revenue requirement, putting downward pressure on electricity rates. Rate impacts have a direct outcome on how much customers pay for electricity and can therefore affect affordability. In this subsection, we first discuss benefits relevant to investment deferral scenarios, and then discuss benefits that apply in Bridge-to-Wires scenarios.

3.1.1. Deferred Investment Costs

As previously depicted by Figure 12, sufficient dispatch of DERs in locations facing forecasted grid constraints can defer investments in new infrastructure. This deferral creates measurable economic value, which we quantify by comparing the cost of the original investment and the discounted cost of making that same investment at a later date. By delaying infrastructure upgrades, an EDC can reduce its revenue requirement and ultimately benefit customers by putting downward pressure on rates.

Methodology

The benefit of deferred investment cost is calculated based on the discounted value of the deferred investment. We first calculate the revenue requirement of the investment—the money a utility will charge ratepayers through electric bills to pay for the costs of the infrastructure and earn an authorized return. The revenue requirement is calculated for both the original (non-deferred) investment that would occur in Year 0 and the deferred investment which occurs in a specified future year. The revenue requirement includes the utility's operating expenses, depreciation of the investment, taxes, and an approved rate of return.

Next, for the two investment scenarios, the annual revenue requirements are discounted back to the present using a net present value (NPV) calculation to express the value of future cash flows in today's dollars. The deferred investment cost is calculated as the difference between the NPV of the original (non-deferred) investment and the NPV of the deferred investment's revenue requirements.

Illustrative Results

To illustrate a deferred investment example, imagine that a substation expansion is planned to be in service by 2032 to address an expected capacity shortfall. Relevant input values are presented in Table 1; these values are illustrative and not intended to reflect actual costs. The hypothetical expansion will cost $100,000,000 and its useful life is 40 years, with the cost depreciating at a straight-line rate of 2.5% over those 40 years.[24] The revenue requirement of this original investment for each year is calculated in the No Deferral section of Table 2 as the net book value (capital cost minus the depreciated asset value) multiplied by the annual revenue requirement allocator[25] and adjusted for distribution line losses[26]. Assuming an 8% discount rate to align with a utility's weighted cost of capital, the NPV of the revenue requirement is approximately $76.6 million.

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[24] Straight-line depreciation distributes the capital cost of an asset evenly across its expected life. In this instance, 100% / 40 years = 2.5% per year, ignoring potential salvage value for simplicity.

[25] The revenue requirement allocator refers to the percent of a project's capital that will be annually recovered via the revenue requirement. It represents recovered costs from depreciation, operating expenses, taxes, and the return on the investment.

[26] The distribution line loss factor reflects the energy savings that occur by consuming electricity where the electricity is generated by a DER, avoiding the energy losses that occur when transmitting power over distribution lines.

Table 1. Example Deferral Valuation Inputs **(Values are Illustrative Only)**

Key	Attribute	Formula	Value
A	Cost Escalation	*input value*	6%
B	Straight-line Depreciation Rate	*1 / Investment Useful Life (Ex: 40 years)*	2.50%
C	Discount Rate (Utility WACC)	*input value*	8%
D	Annual Revenue Requirement Allocator	*input value*	12.5%
E	Line Losses	*input value*	9.8%
F	Capital Cost - No deferral ($M)	*input value*	$ 100
G	Capital Cost - 3-year deferral ($M)	*F * (1+ A) ^3*	$ 119

Table 2. Example Deferral Value Calculation **(Values are Illustrative Only)**

Key	Attribute	Formula	Values										
	Year		Year X	X+1	X+2	X+3	X+4	...	...	...	...	...	...
H	Discount Year		0	1	2	3	4	...	39	40	41	42	43
	No Deferral												
I	Year of Investment Life		0	1	2	3	4	...	39	40			
J	Rev Req ($M)	*F * D * (1 - B * I) / (1 - E)*	$ 13.9	$ 13.5	$ 13.2	$ 12.8	$ 12.5	...	$ 0.3	$ -	-	-	-
K	Rev Req NPV ($M)	*NPV (Row J discounted at C)*	*$ 76.6*										
	3-year Deferral												
L	Year of Investment Life					0	1	...	...	...	38	39	40
M	Rev Req ($M)	*G * D * (1 - B * L) / (1 - E)*	-	-	-	$ 16.5	$ 16.1	...	...	...	$ 0.8	$ 0.4	$ -
N	Rev Req NPV ($M)	*NPV (Row M discounted at C)*	*$ 72.4*										
O	Savings from 3-year Deferral ($M)	*K - N*	*$ 4.2*										

In a deferred investment scenario, imagine that DERs provide flexible load to alleviate risk of a capacity shortfall (recall Figure 12) such that the EDC can defer the investment for an assumed 3 years. Over those 3 years, inflation causes the cost of the project to escalates by 6% each year, resulting in a capital cost of $119 million. Calculating the revenue requirement of the deferred investment in the same manner as the original scenario, the resulting NPV is $72.4 million. The difference in NPVs from the 3-year deferral results in a savings and deferral value of $4.2 million.

This $4.2 million represents the value that can be split between total spend on a Grid Services offering (including DER compensation and other program costs) and benefits to ratepayers. Put another way, $4.2 million would be the upper bound for spend on Grid Services offerings without increasing costs for non-participants, and if deferral can be achieved at a lower cost, ratepayers save the difference.

Note that this specific deferral value is only intended as an example and actual values will vary significantly by location and over time. It is possible to have a negative deferral value in instances where costs for system upgrades are increasing rapidly, wherein it may be cheaper to build something today than to wait while prices rise. This is a relevant concern today, as the cost of distribution transformers in particular is rising dramatically due to a spike in demand, shortage of supply, and potential tariff impacts on the horizon.[27] As we discuss further in Section 4.1, when and where deferral values are very low, it does not make sense to offer compensation to DERs because the cost of providing sufficient DER incentives may outweigh the value of deferral. This range in potential costs is why it is important to evaluate Grid Services for each specific project deferral opportunity.

3.1.2. Incremental Investment Value

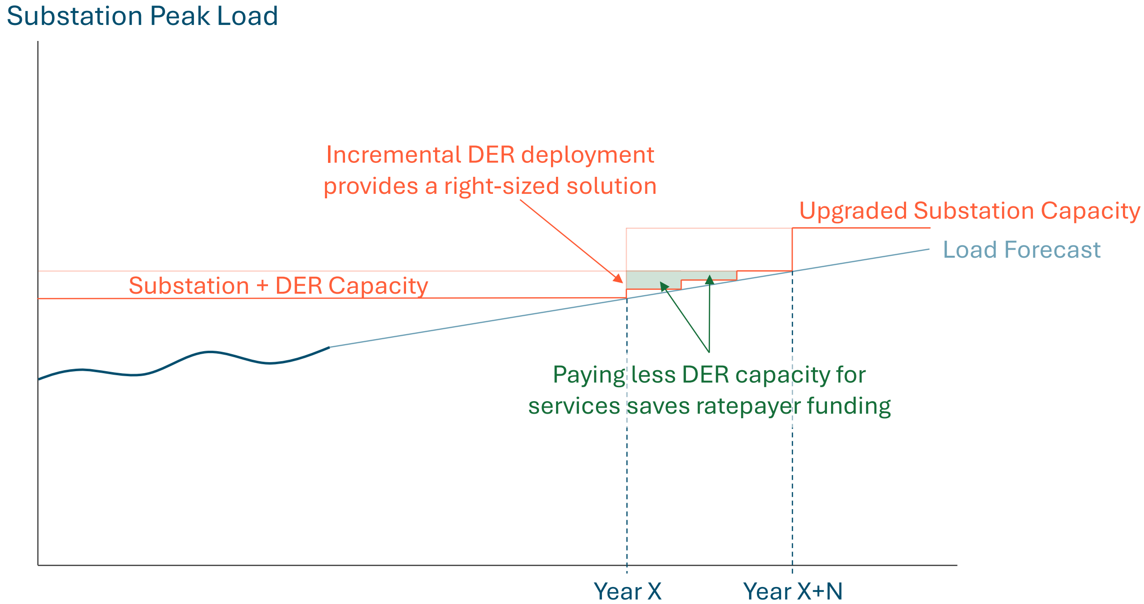
Distribution planners design infrastructure upgrades for long-term functionality: ideally, a new piece of equipment with a 40-year useful life will be sized to accommodate any load growth that occurs over those 40 years. Accordingly, upgrades tend to be "oversized" relative to immediate need, which increases the initial equipment cost but saves on cost over the long term by avoiding the need for future labor or early retirement of undersized equipment.

When calling upon DERs to defer infrastructure need, distribution operators can right-size their annual procurement. If multi-year deferral is expected, instead of dispatching and paying DERs every year for the maximum capacity that will be needed over the entire deferral period, grid operators can choose to only dispatch and pay each year for the DER capacity that is needed in the given year. This concept is illustrated by Figure 16, which provides the same deferral and therefore same total benefit as the deferral solution in Figure 12. However, DER dispatch is right-sized in Figure 16 to only mobilize as much capacity as needed for each year. Dispatching fewer kW-years over the lifetime of a deferral opportunity should mean spending fewer dollars on compensation and therefore reserving more of the total deferral value for ratepayers.

It is important to note that this value of incremental investment is an implementation benefit. It does not change the total value of deferral. Accordingly, this benefit should not be used to inform the total compensation.

[27] "Major Drivers of Long-Term Distribution Transformer Demand", NREL, (2024). https://docs.nrel.gov/docs/fy24osti/87653.pdf

Figure 16. Savings through Incremental Acquisition of DER Capacity



We also expect this benefit to be more available in future years compared to early years of Grid Services offerings. DER response must be sufficiently reliable in order to supplant traditional distribution grid infrastructure. Today, grid planners may need additional data to understand the operational reliability of a pool of DERs or will need to enroll sizable margins of DER capacity above what is strictly required for deferral. Without this, they will not be able to confidently delay an infrastructure investment. However, as distribution forecasting progresses, communications with DERs improve, and operators build more experience dispatching DERs for deferral, grid operators will be able to more safely plan and operate with smaller margins of DERs. This confidence should translate to more ratepayer savings.

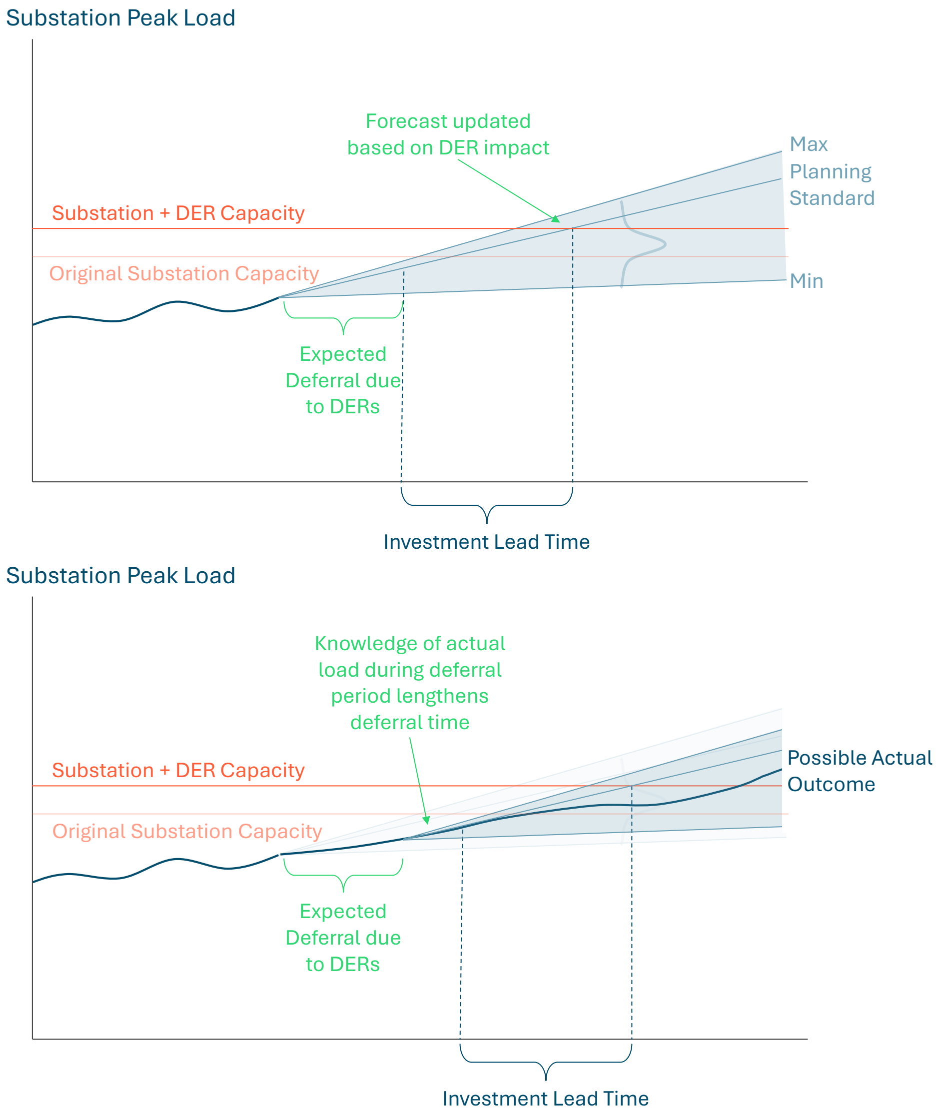
3.1.3. Optionality Value

The optionality value of DERs reflects the additional potential benefit of waiting to make investments—and keeping options open—in the face of uncertainty. Distribution system planning is inherently uncertain: load growth may be faster or slower than originally forecasted, new technologies may evolve, infrastructure costs may fluctuate, and policy or customer behavior may shift in unexpected ways. Being at the beginning of an energy transition, the level of uncertainty in many of these factors is even higher as adoption of electrified technologies (EVs, heat pumps, etc.) plays out, grid and DER-related technologies evolve and become more efficient, and rates, programs, and incentives related to all of the above are being developed and iterated on. Methods of managing that uncertainty are therefore valuable. By leveraging DERs to meet capacity needs, EDCs gain valuable time to reassess forecasted needs and embrace new technological advances before committing to large capital-intensive investments.

Some aspects of an optionality value cannot be quantified. For example, technological advancement will provide positive value, but the dollar value of this benefit cannot be predicted.

However, the expected value of improved forecast knowledge can be quantified if the uncertainty inherent in the load forecast is understood. We describe a process to quantify this value in Appendix C. and present a summary in Figure 17.

Figure 17. Optionality Value Resulting in Additional Deferral Years



The top panel of Figure 17 mimics the familiar deferral scenario of Figure 12, but now we acknowledge the lead time between deciding to make an investment and project completion. This non-zero lead time means that investment decisions are always made based on uncertain load growth forecasts. In Figure 17, this uncertainty manifests as the shaded region between the minimum and maximum load growth lines. In the bottom panel, we show that deferral of the decision point improves knowledge of actual load growth, represented by a narrower shaded region of possible forecasted outcomes. When actual load growth is slower than expected during this period, additional years of deferral may be achievable with the same DER capacity. The expected value over many possible load growth outcomes of this additional deferral is a quantifiable measure of the value of optionality.

While the value of optionality is a real and well-established benefit in delaying electric system investments[28], the approach to calculating this value relies on data which are not yet available in Massachusetts (i.e., distributional rather than single-valued forecasts of load growth). As such, we do not propose that an optionality value be incorporated in valuing Grid Services at this time but recommend that it be reconsidered as distribution planning processes continue to evolve and embrace new technological advances. In the meantime, optionality value can be understood as a relatively small incremental increase to the expected deferral value, as shown by the example in Appendix C.

3.1.4. Avoided Backup Resource Costs

In a Bridge-to-Wires scenario (introduced in Section 1.2.2), no deferral of investment is necessarily taking place, because the local EDC is still moving forward with planning and building out infrastructure as soon as possible to meet the anticipated capacity need. However, because the infrastructure is not expected to be in place in time to serve the projected need, the EDC may incur costs to deploy temporary alternative solutions, such as backup resources. The Grid Services value of DERs as a Bridge-to-Wires solution comes from avoiding the costs of those backup resources.[29]

The methodology to calculate the avoided costs of backup generation represents one recommended framework for determining the value of DER Grid Services in a Bridge-to-Wires scenario. In practice, the EDCs will determine the value of DERs at specific grid locations based on actual costs and operating conditions forecasted for the Bridge-to-Wires scenario.

Methodology

To quantify the avoided cost associated with emergency backup generation resources, we calculate the annualized marginal cost of two commonly deployed interim solutions: diesel generator backup and battery energy storage. For both solutions, we only quantify the expenses incurred by the EDC to procure and operate these resources as a rate impact. Other impacts from use of these resources that may be avoided through the use of DERs, such as emissions, are valued as non-rate impacts, described in Section 3.2.

The avoided cost of diesel generation is estimated based on the operational expenses incurred from renting and running a diesel generator. The operational expenses include the generator rental cost, setup and breakdown costs, and fuel costs. The approach for estimating the avoided cost of battery

[28] Bustard, J., Clauhs, B., & Price, S., "Profitability and risk assessment of T&D capital expansion plans", LBNL, (1995). https://escholarship.org/content/qt6hc78827/qt6hc78827.pdf?t=qo7q9d

[29] The project partners also considered other responses to these scenarios as alternatives forms of valuation, including the impacts on asset life of operating existing equipment outside of standard operating limits or in non-standard configurations. These impacts were not able to be quantified with readily available data and methods but may also result in indirect costs to ratepayers. The cost of resources is thus used as a proxy value across Bridge-to-Wires scenarios

storage mirrors the diesel generator methodology, relying on estimates of operational expenses of deploying battery storage.

For either backup resource, the rental cost and setup and breakdown costs depend on the size of the unit needed, the timeframe over which it is needed, and the location of the Bridge-to-Wires need. For example, deploying generators or battery storage to the more urban regions of eastern Massachusetts or to the Commonwealth's islands is more expensive than deploying the same resource in more rural locations, in western Massachusetts.

The fuel costs for diesel and energy storage backup scale with the generator's assumed usage. We assume that the backup resource will operate 240 hours annually (8 hours/day for 30 days/year) to provide generation during critical peak periods of the year.[30] The fuel costs for a diesel generator are based on EDC estimates and the electricity prices to charge the battery storage are an average of summer off-peak wholesale prices.[31]

Because backup generation is sized to meet each specific Bridge-to-Wires need, it is natural to normalize this value by dividing the total avoided cost by the generator capacity to give an annualized marginal cost expressed in $/kW-year.

Illustrative Results

Based on representative costs of backup diesel generation and battery storage provided by the EDCs, we have estimated high, medium, and low avoided costs according to the location of the Bridge-to-Wires solution in Massachusetts. The avoided cost of backup diesel generation could range from $58/kW-yr to $200/kW-yr, as shown in Table 3. The estimated avoided cost of battery storage is estimated to be higher at $220/kW-yr. Like backup diesel generation, the cost of battery storage will depend on its location in Massachusetts. To reflect the varied cost, we apply a 200% multiplier to a high-cost location, a 125% multiplier to a medium-cost location, and a 75% multiplier to a low-cost location, as illustrated in Table 3. These cost multipliers apply prior to the addition of charging cost.

Table 3. Avoided Cost of Diesel Generation and Battery Storage

Avoided Resource	High ($/kW-yr)	Medium ($/kW-yr)	Low ($/kW-yr)
Diesel Generation	$200	$100	$58
Battery Storage	$441	$276	$165

In some cases, an EDC may weigh the avoided cost for a given location by the probability or blend of backup solutions that would be deployed in the absence of DERs. For example, in a medium-cost location, if a blend of different backup solutions would otherwise be used, weighting diesel generation as 90% of the preferred backup solution and weighting battery storage as 10% of the

[30] 240 hours per year is a general assumption for a generator's usage to cover the hours that experience peak load impacts. This assumption may be updated by EDCs for individual locations depending on the capacity constraint and forecasted load at the location.

[31] Diesel fuel prices and electricity prices for charging battery storage will be updated by the EDCs for individual locations. The average battery charging cost to enable 240 hours of discharge are assumed to be $37/MWh, with a round trip battery efficiency of 85%.

preferred solution would lead to an avoided cost of $118/kW-yr. At present, the EDCs in Massachusetts generally utilize backup generation and do not employ storage as a temporary solution on a regular basis as it is not as economic, and the availability of temporary, mobile storage is limited in the marketplace. Storage is included in this analysis as it is expected to increase in usage as a backup solution in the future as technology and economics improve. If storage is used as a proxy cost in the future, the assumed costs should be revisited to reflect any improvement in economics.

3.2. Non-Rate Impacts of Grid Services

Non-rate impacts do not directly alter an EDC's revenue requirement and customer rates. Non-rate impacts may include environmental externalities, public health improvements or dangers, or other societal outcomes. In this valuation framework, we specifically highlight environmental justice-related impacts as non-rate impacts given the importance of improving equitable access to grid benefits and addressing historical inequities in the energy system.

These impacts are valued separately from the rate impacts because their inclusion in compensation can put upward pressure on electric rates, thereby causing unintended cost shifts among customers. Because of this possibility, policymakers should be cautious about including non-rate impacts in rate-funded compensation. However, this broad category of impacts is important to consider in terms of other policy goals, such as reliability, environmental justice, equity, and economic development.

The diversity of non-rate impacts means that they are evaluated in a variety of different ways. Some of these impacts, like the impact of power outages (lost load) or local air quality impacts, have well established methodologies for understanding the financial implications for customers and communities. Other impacts, such as the ability to interconnect new load or generation sooner, noise pollution, or short-term construction job growth, are concrete but are difficult to represent with confidence as dollar values. We also include several impacts identified by stakeholders that may represent either positive or negative outcomes for the grid and local communities.

As Grid Services offerings are implemented, further impacts may be realized or may begin to be quantified based on on-the-ground observations as well as learnings from other jurisdictions. In the future, policymakers may choose to recognize additional impacts in Grid Services compensation or through other mechanisms. At this time, the only non-rate impacts that we recommend inform Grid Services compensation levels are the Environmental Justice Impacts discussed in Section 3.2.1. Within that section, we describe how some impacts may be translated into adders for compensating qualifying DER projects to support Grid Services participation, specifically in environmental justice communities.

3.2.1. Environmental Justice Impacts

It is widely recognized that non-rate impacts can support desired outcomes even where they are not able to be directly quantified. In many jurisdictions, benefit-cost analyses have included these non-rate benefits when evaluating energy efficiency programs, especially for low-income customers.[32] These benefits include aspects such as productivity, customer health and safety, home or business value, energy security or independence, and comfort.[33] These impacts are typically evaluated through quantitative means where possible and elsewhere through proxy adders, which can either be applied to the benefit side of a benefit-cost analysis or lower the threshold for the benefit-cost analysis to be below 1.0. We used the ACEEE Guidelines for Low-Income Energy Efficiency Programs to examine how other jurisdictions apply these proxy adders when unable to quantify all non-rate benefits.[34] Using data from ACEEE and the Northeast Energy Efficiency Partnerships, we found examples of 11 states applying proxy adders to programs that target low-income customers to adopt electric devices that aid grid operations.[35] Most of these programs range from 5% to 30% adders, depending on the program and the state. Similarly, the SMART program offers low-income customers an additional export credit of $0.03/kW, which is equivalent to approximately 20% to 30% additional compensation.[36] This order of magnitude is also consistent with the 2022 Inflation Reduction Act's Investment Tax Credit adders for projects in low-income communities (10%) or benefiting low-income residents (20%), which also provide compensation for the innate value of supporting new technologies that benefit low-income or disadvantaged customers.[37] Using this context, we recommend 20% as a midpoint value for an EJ adder.

3.2.2. Value of Lost Load

The value of lost load calculation utilizes the Interruption Cost Estimate (ICE) Calculator 2.0[38] funded by the Department of Energy and developed by the Lawrence Berkeley National Laboratory. Based on a utility's reliability metrics and customer counts, the ICE Calculator estimates the cost per average kW of interruption. As inputs to the ICE Calculator, we assume that a customer outage resulting from a capacity overload would occur only once per year and that the outage would last for 12 hours. These inputs were chosen in collaboration with the EDCs to account for the highest-risk hours during the year. This corresponds to a SAIFI (System Average Interruption Frequency Index) of 1 day and a SAIDI (System Average Interruption Duration Index) of 720 minutes (12 hours x 60

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[32] "Guidelines for Low-income Energy Efficiency Programs", ACEEE. https://database.aceee.org/state/guidelines-low-income-programs

[33] "Applying Non-Energy Impacts from Other Jurisdictions in Cost-Benefit Analyses of Energy Efficiency Programs", LBNL, (2020). https://eta-publications.lbl.gov/sites/default/files/nei_report_20200414_final.pdf

[34] "Guidelines for Low-income Energy Efficiency Programs", ACEEE. https://database.aceee.org/state/guidelines-low-income-programs

[35] This study considered low-income EE and DER program cost-effectiveness metrics across states including CA, CO, DC, IA, IL, NH, NM, NV, NJ, VT, WA. "Guidelines for Low-income Energy Efficiency Programs", ACEEE. https://database.aceee.org/state/guidelines-low-income-programs . "Non-Energy Impacts Approaches and Values", NEEP, (2017). https://neep.org/sites/default/files/resources/NEI%20Final%20Report%20for%20NH%20updated%2010.4.17.pdf

[36] "SMART 3.0 Program Details", Massachusetts DOER. https://www.mass.gov/info-details/smart-30-program-details

[37] "Clean Electricity Low-Income Communities Bonus Credit Amount Program. U.S. IRS. https://www.irs.gov/credits-deductions/clean-electricity-low-income-communities-bonus-credit-amount-program

[38] "Interruption Cost Estimate (ICE) Calculator", U.S. DOE, LBL, Resource Innnovations. https://icecalculator.com/

minutes), resulting in a CAIDI (Customer Average Interruption Duration Index) of 720 minutes (SAIDI / SAIFI).

To represent the relative risk of an outage in different locations of the distribution system, we adjust the customer count input to the ICE Calculator by altering the proportion of residential and non-residential customers. The economic risk of an interruption is greater for non-residential customers than for residential customers, because commercial and industrial customers typically place greater monetary value on maintaining uptime for their systems and equipment. For example, an hourlong electrical outage at a business may mean an hour's lost productivity for dozens of workers, or an outage at a hospital may pose a critical concern and require use of emergency backup generators. The monetary cost therefore reflects the mix of customers experiencing the outage. We assume a high-economic risk location has a higher proportion of commercial and industrial customers than the statewide average (70% residential, 30% non-residential), a medium-risk location reflects the current statewide split of non-residential and residential customers (86% residential, 14% non-residential), and a lower-risk location has a higher proportion of residential customers (95% residential, 5% non-residential).[39]

The cost per average kW for the assumed reliability metrics and customer counts for the state of Massachusetts is reported in Table 4. While relatively straightforward to quantify, the value of lost load is not appropriate to include in the calculation of a Grid Services compensation for two reasons: First, loss of load is not an expected outcome for a Bridge-to-Wires scenario—the more likely outcome is use of backup generation or running infrastructure above standard levels. Second, the value of avoiding lost load accrues to the customers who avoid outages and does not impact utility revenue requirements.

Table 4. Cost per Average kW Interrupted resulting from the ICE Calculator[40]

Sector	Fraction of Residential Customers Assumed	Cost per Average kW (2025 $)
Residential	100%	$46
Non-Residential	0%	$989
All Customers (Low)	95%	$54
All Customers (Medium)	86%	$70
All Customers (High)	70%	$107

3.2.3. Air Quality Impacts

If an EDC would traditionally deploy a diesel backup generator in a Bridge-to-Wires scenario, the neighborhood would experience air pollution and air quality impacts. By drawing upon flexible DER

[39] These measures of risk are purely in generic financial terms.

[40] The All Customers results from the ICE Calculator are not weighted averages of residential and non-residential customers; the outputs must be generated by running the ICE Calculator.

capacity instead of a backup diesel generator, we can avoid the costs of air pollution in addition to avoiding the operational costs of the generator itself. The avoided air quality impacts are societal outcomes and are therefore quantified as non-rate impacts.

To quantify the air quality impacts of diesel generators, we estimate the cost of nitrous oxide (NOx) and sulfur oxide (SOx) pollution. Emission factors for NOx and SOx are sourced from the U.S. Environmental Protection Agency (EPA) and are specific to two representative diesel engine types[41]: (1) uncontrolled diesel industrial engines[42] and (2) large stationary diesel engines.[43]

Each set of emissions factors, summarized in Table 5, are modeled in the EPA's CO-Benefits Risk Assessment (COBRA) Health Impacts Screening and Mapping Tool.[44] COBRA estimates the monetized health impacts of air pollution, such as premature mortality, hospital admissions, and lost work and school days, on a $/GWh basis. For this analysis, we apply the "high" monetary value estimates to reflect the upper-bound societal costs of air pollution and convert the outputs to $/kWh, as detailed in Table 6.

Table 5. Diesel Engine Emission Factors

Engine Type	Air Pollutant	Emission Factor (lb/hp-hr)[45]	Emission Factor (lb/kWh)	Emission Factor (short tons/kWh)
Uncontrolled Diesel Industrial Engines	NOx	0.0310	0.0231	0.0000116
	SOx	0.0021	0.0015	0.0000008
Large Stationary Diesel Engines	NOx	0.0240	0.0179	0.0000089
	SOx	0.0004	0.0003	0.0000002

Table 6. Health Impacts of Diesel Engines[46]

Engine Type	Health Impacts - High ($/kWh)
Uncontrolled Diesel Industrial Engines	$0.50
Large Stationary Diesel Engines	$0.37

To derive the annualized cost estimates for a Bridge-to-Wires scenario, we multiply the $/kWh air pollution cost calculated from COBRA by the assumed operating hours of the generator. Consistent with the assumptions for calculating the rate impacts of avoided operating expenses, we assume

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[41] The selection between these two engines will depend on which generator type an EDC would most likely deploy in a specific Bridge-to-Wires location.

[42] AP-42, Vo. I, 3.3: Gasoline and Diesel Industrial Engines, U.S. EPA. https://www3.epa.gov/ttnchie1/ap42/ch03/final/c03s03.pdf

[43] AP-42, Vo. I, 3.4: Large Stationary and All Stationary Dual-fuel Engines. U.S. EPA. https://www.epa.gov/sites/default/files/2020-10/documents/c03s04.pdf

[44] CO-Benefits Risk Assessment (COBRA) Health Impacts Screening and Mapping Tool, U.S. EPA. https://www.epa.gov/cobra

[45] lb/hp-hr refers to pounds per horsepower-hour. Horsepower is a unit of measurement for engine-generated power.

[46] Estimated Using the EPA COBRA model.

that the generator operates 240 hours each year (8 hours per day over 30 days). This results in an air quality value of $108/kW-yr based on the uncontrolled diesel industrial engine emission factors and a $67/kW-yr value based on the large stationary diesel engines emission factors.

3.2.4. Degradation of Infrastructure from Operating Under Non-Standard Conditions

In a Bridge-to-Wires scenario, situations may arise where absent the use of DERs, EDC grid operators elect not to rely on other backup resources. This decision may be made where existing grid infrastructure is strained but still deemed sufficient to support expected demands. Equipment is then operated near its maximum capacity or in non-standard configurations to support customer loads. This can cause equipment to degrade faster, requiring it to be replaced sooner and thus incurring future costs. Grid Services provided by DERs can help avoid this situation and the resulting costs for the grid of early equipment retirement.

The specific value of avoiding this degradation is difficult to assess. Variables that would affect this value include the cost of each piece of equipment under stress, its standard expected useful life, and the impact on useful life due to non-standard operating conditions. The latter requires knowledge of the exact behavior of local system load and likelihood of equipment failure. We explored this value with the EDCs and through literature review but do not quantify it within this study. The value of alternative backup resources is instead used as a proxy quantifying rate impacts in all Bridge-to-Wires scenarios.

3.2.5. Ability to Accommodate Load Growth

One notable benefit stemming from the flexibility that DERs provide is the ability for new loads to interconnect to the distribution grid sooner. If DERs shift load to hours when a grid asset is less constrained, the grid can accommodate a greater amount of new load without the need for an interconnection upgrade. This capability can bolster specific climate or social policies, including economic development and environmental justice. For example, Grid Services from DERs can support more EV charging, enabling a key piece of Massachusetts' Clean Energy and Climate Plans and reducing air pollution from conventional gas or diesel vehicles. Additionally, in areas with insufficient capacity to support new loads related to economic development, DERs could provide capacity to enable interconnection.

We note that the ability to accommodate load growth is distinct from the ability to interconnect DERs. For the latter, it is possible to use flexible interconnection agreements in which DERs accept possible curtailment or other management to avoid triggering the need for equipment upgrades but Massachusetts has yet to adopt flexible interconnection at scale. Grid services offerings are focused on using DER to meet pre-existing grid needs, which is distinct from a dedicated flexible interconnection offering that allows new DERs to connect while minimizing their impact on the distribution grid. However, flexible interconnection and Grid Services may complement each other, as flexible interconnection can promote faster adoption of dispatchable DERs that can provide distribution Grid Services.

We also note that there is a benefit to the load that would be able to interconnect sooner, through faster expansion of business or some other metric. However, this benefit accrues to the new load and not to ratepayers in general, so we do not recommend it be considered as a benefit related to compensation. Furthermore, we discourage the possible model in which those wishing to interconnect sooner can provide funding for DERs to allow them to do so, since this would create an inequitable pay-to-play arrangement.

It is difficult to reliably quantify the benefit of load growth accommodation because the impacts will vary depending on the underlying rate design and the nature of the connected load vis-à-vis system headroom. While load growth can put downward pressure on electric rates, growth that requires infrastructure upgrades is less likely to have this beneficial impact. If the infrastructure upgrade need applies only at the distribution level, the new load may suppress transmission- and policy-related rate components, but this impact depends on how rates are designed to collect these costs from the new load and existing customers. This uncertainty motivates us to not quantify this possible benefit and to not recommend it for inclusion in determining compensation for Grid Services.

3.2.6. Other Localized Non-Rate Impacts

In addition to the quantified non-rate impacts, several other potential impacts of Grid Services are identified in the literature or have been raised by stakeholders. These impacts are recognized below, though E3 does not necessarily endorse every topic for inclusion in a valuation framework. Each of these following impacts are also non-rate impacts, meaning that they would not factor into a utility's revenue requirement or contribute to putting downward pressure on electric rates.

Economic and Jobs Impact: Construction of new distribution infrastructure in a potential deferral scenario or the installation of traditional backup in a Bridge-to-Wires scenario may lead to localized economic development and jobs impacts. By deferring or avoiding these traditional solutions through the use of DERs, benefits and job impacts might be similarly deferred or lost. At the same time, DER adoption spurred by Grid Services compensation in combination with other value streams may create jobs for local businesses involved in installing DERs. These impacts would require regional macroeconomic modeling to quantify and are out of scope for this analysis. For Bridge-to-Wires solutions, the tradeoff between installing and operating traditional backup and DERs is also expected to be negligible.

Localized Construction Impacts: Deferral of a distribution upgrade project or avoiding local Bridge-to-Wires generation projects can bring short-term benefits to the community by delaying or avoiding common disruptions like noise, poor air quality, and traffic congestion. However, there is no clear consensus if deferral of these projects provides a benefit in the long term. Some impacts may simply be postponed rather than avoided, while in other cases, the delay can allow time for better planning and coordination that helps minimize these issues when the project does move forward. Localized construction impacts are difficult to quantify financially because they are often subjective or vary widely in nature on a project-to-project basis. For that reason, E3 did not model them quantitatively.

Local Ownership: Several stakeholders have suggested that increased penetration of DERs can increase local control of energy systems and support democratized community-driven planning and the generation of local wealth. By providing an additional compensation stream to help unlock DER adoption, these offerings give communities more say in how electricity is produced, managed, and distributed. This empowerment can help residents shape energy decisions around their specific needs and values while also creating opportunities to mitigate historical harms, such as inequitable access to reliable power or the siting of polluting infrastructure. The value of this local control is, however, difficult to quantify. Because the benefits depend on community context and are tied to social and governance outcomes, we address them qualitatively to recognize their significance, absent a precise dollar value. While this is a benefit of DER adoption, this is not specific to the Grid Services offering or compensation value.

Pride in Grid Contributions: Participating in this type of offering can give individuals a sense of pride and ownership in contributing to a cleaner and more reliable energy future. Knowing that their homes, businesses, or neighborhoods are actively helping to reduce reliance on fossil fuels and support a stronger, more reliable grid can foster a stronger connection to the energy system and a shared sense of responsibility. This pride can boost community morale and engagement, especially in areas where residents have historically been excluded from energy decision-making. While this kind of civic pride and environmental stewardship does not factor into an avoided utility cost analysis, it plays an important role in public support and long-term success of clean energy programs, making it a valuable qualitative benefit. While this is a benefit of DER adoption, this is not specific to the Grid Services offering or compensation value.

Participant Bill Benefits: A few stakeholders have noted that customers with DERs will see bill savings by using their DERs to reduce their load and requested that this value should be recognized. While this is often a primary driver in DER adoption, it is a benefit solely accrued to participants, which is already realized by those participants on their bills. Therefore, this is not an incremental value to be compensated nor specific to Grid Services.

4. Near-Term Implementation

The following sections of this report serve as a roadmap for translating the valuation of Grid Services into compensation offerings to realize that value. The Massachusetts EDCs will ultimately be responsible for implementation. National Grid has already started designing and testing out individual offerings and the EDCs will continue to do so leading up to the 2029 filing of their updated ESMPs. This Near-Term Implementation section recommends objectives for the EDCs to pursue over these first 5 years of trials. The section then discusses means to determine compensation levels, considerations for designing compensation mechanisms, potential challenges for implementation, and avenues for EDCs and the Commonwealth to receive and recognize stakeholder feedback.

The design and administration of the offerings are expected to change over time as the trial offerings provide new insights. This roadmap is intended to present clear goals and guideposts but is not prescriptive with regard to specific details of the offerings.

Near-Term Objectives

Localized Grid Services offerings will be a new undertaking for Massachusetts, and the near-term period of implementation will offer valuable data for establishing more permanent offerings. A goal for the next 5 years of implementation is for the EDCs to learn by doing and understand how to effectively leverage the flexibility of DERs to support the grid. Near-term objectives should therefore prioritize information gathering as they explore ways to realize the many benefits of Grid Services. The objectives developed through the public stakeholder process and collaboration with the project partners are to:

1. **Test and refine Grid Services offerings and implementation approaches**
2. **Identify data and process requirements to take full advantage of Grid Services**
3. **Understand DER market capabilities, needs, and appetite for Grid Services offerings**
4. **Provide ratepayer savings via investment deferral**
5. **Mitigate system risks in Bridge-to-Wires scenarios to enable electrification**

These objectives will be supported by a combination of many individual actions and processes.

For any of these objectives to be realized, the EDCs must begin by identifying areas of the system where DERs can provide Grid Services value. The EDCs will need to determine the specific costs that DERs can defer or avoid through Grid Services, as well as how much capacity will be needed, under what conditions, and for what period of time. The EDCs must subsequently determine appropriate bounds on the level of compensation based on the value provided to the grid and develop compensation mechanisms, as will be discussed in the following subsections. Putting new methods and designs into practice will reveal gaps in existing data or processes, which will need to be filled. For trial offerings to succeed and provide useful insight, the EDCs and Commonwealth must also create channels to educate potential participants and other stakeholders about the offerings and have transparent processes in place to receive and act on feedback.

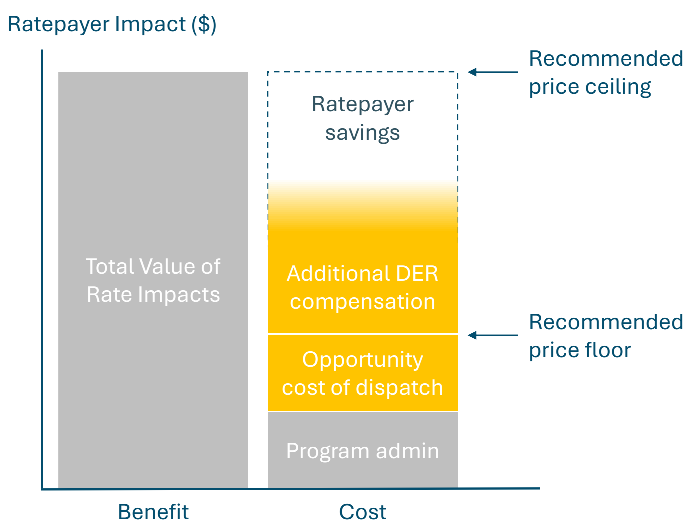
4.1. Determining Reasonable Compensation for Grid Services

After determining the Grid Services value DERs can provide in a specific location, the EDCs will need to decide how much of that value to offer as compensation to participants. Given the recommended prioritization of generating ratepayer savings (see Section 2.2), the deferral or Bridge-to-Wires value can set a ceiling to cover both compensation itself and all other costs of administering a program that might ultimately be recovered from ratepayers.

Meanwhile, an effective floor for compensation can be set based on what price signals are needed to elicit a response from DERs. This value will reflect a DER owner's opportunity cost for dispatching their DER during the times required by the Grid Services offerings instead of using their DER for other purposes, such as responding to price signals from other programs or the wholesale market, reserving capacity to provide backup power, or shifting or reducing the DER owner's own load. Section 4.1.2 demonstrates this opportunity cost for select DER use cases.

Figure 18 depicts the determination of these floor and ceiling values based on the benefits and costs of Grid Services from the ratepayer's point of view. The benefits consist of the rate impacts identified in Section 3.1. The costs include costs associated with program administration[47] and the compensation paid to DERs for their dispatch (shown in gold). We break this compensation bar into the "opportunity cost of dispatch" and "additional DER compensation" in order to highlight the recommended definition of the price floor. Any difference between the benefits and costs shown in the figure manifests as ratepayer savings.

Figure 18. Recommended DER Compensation Floor and Ceiling Values Based on Ratepayer Benefits and Costs



[47] This category includes expenses for designing the offerings, conducting outreach, enrolling and managing participating DERs, and organizing studies to locate and determine the potential avoided cost value of eligible Grid Services sites. In either a deferral or Bridge-to-Wires scenario, there may also be sunk costs for investments made before either Grid Services offerings could be deployed or sufficient DERs could be dispatched to meet system needs.

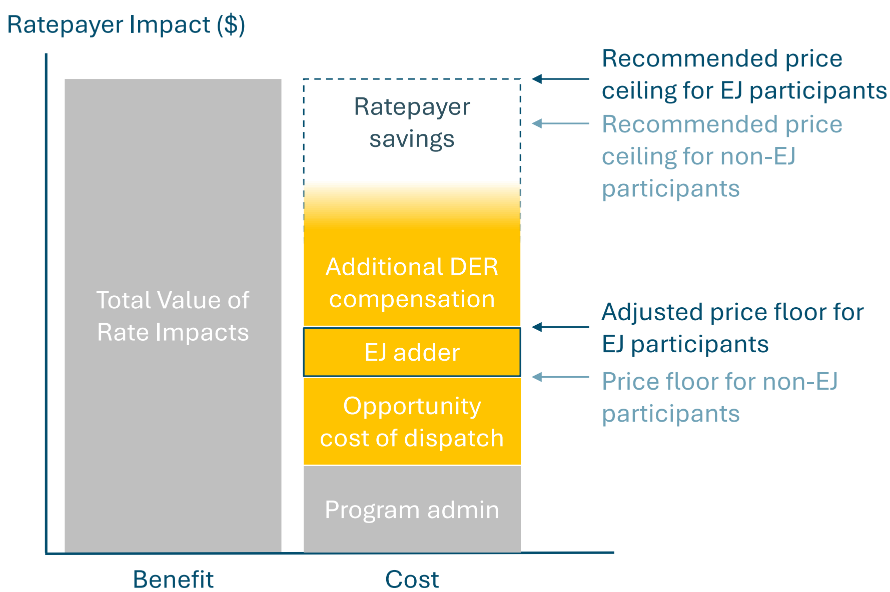
These bounds serve as useful guides regardless of Grid Services offering design. An offering that leverages a flexibility marketplace can use the bounds to set a market price floor and cap. An offering using an administratively determined compensation value should aim to keep that value below the ceiling. However, in initial years, compensation near or even above the ceiling may be necessary to drive participation.

Within these boundaries, compensation levels represent balance and prioritization among the competing goals of Figure 14. To inform the evolution of offering design, early offerings must garner sufficient participation and be designed with distinct compensation structures to draw conclusions about the impacts of different designs on customer participation and how reliably EDCs can capture Grid Services benefits. As offerings expand, compensation may adjust to reflect learnings and to pass a greater share of benefits on to ratepayers. As implementation processes are solidified, economies of scale and learned efficiencies can reduce per-participant costs for administration and free up more of the total Grid Services value to be split between ratepayers and direct compensation.

4.1.1. Ensuring Ratepayer Benefits

For Grid Services offerings to provide net benefits to ratepayers, the benefits of Grid Services explored in Section 3 must exceed the costs of the offerings. This constraint must be accounted for when considering the suggested EJ adder suggested in Section 3.2. As shown in Figure 19, the inclusion of an EJ adder in the compensation for DERs increases the price floor for EJ participants, which correspondingly decreases ratepayer savings.

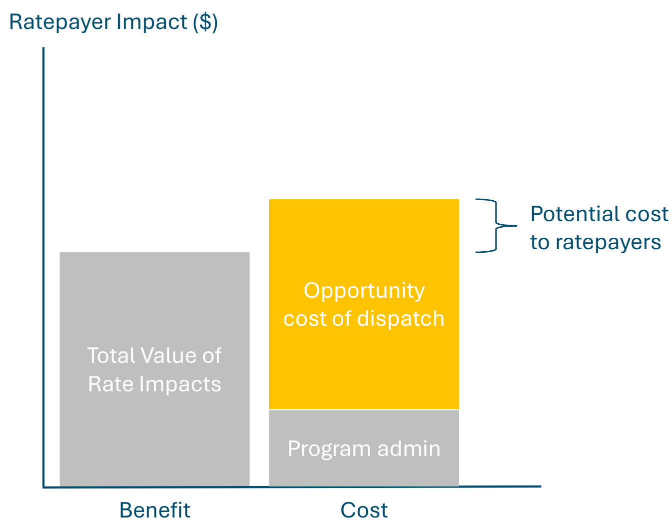
Figure 19. Recommended DER Compensation Floor and Ceiling Values incorporating EJ Adders



Requiring ratepayer savings dictates that compensation paid to DERs be less than the total rate impact benefit, regardless of whether compensation is paid to EJ or non-EJ participants. To ensure that including an EJ adder does not violate the price ceiling, we recommend an effective non-EJ price ceiling be set below the total value of rate impacts by an amount equal to the EJ adder. This approach guarantees that ratepayer savings are generated by non-EJ Grid Services participants and that EJ Grid Services participants do not generate ratepayer costs.

There will be cases in which the rate impacts of a proposed deferral or Bridge-to-Wires opportunity are small relative to potential costs. A visual example of this relationship appears in Figure 20. If at any location the combination of administrative costs plus the opportunity cost of dispatch outweighs the likely benefits, the traditional wires solution is a lower cost outcome for ratepayers than using DER Grid Services. In these cases, DER Grid Services would not provide ratepayer savings and would put upward pressure on rates.

Figure 20. An Example Non-viable Grid Services Scenario



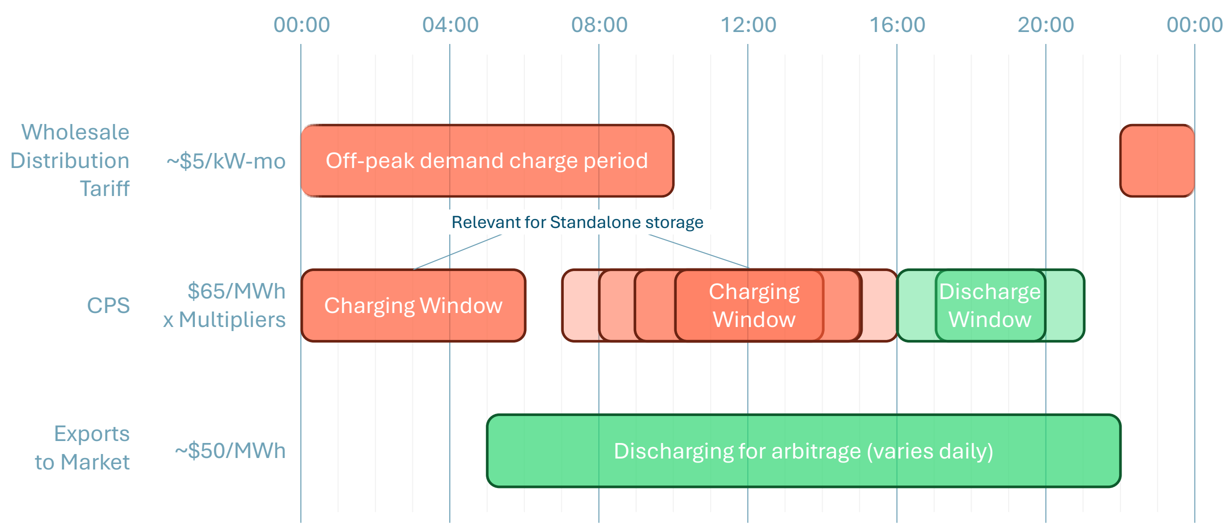
4.1.2. Eliciting DER Response

While Grid Services compensation should fall below the ceiling value to avoid adding to ratepayer costs, compensation must also be above an effective floor price, representing the DER's opportunity cost, in order to elicit DER response. Flexible DERs in the Commonwealth may respond to signals including those from retail rates, wholesale markets, and the DER programs described in Section 1.3. DERs use these price signals to determine dispatch behavior.

To incentivize a DER to respond to a Grid Services call, the compensation for this call must be greater than the revenue lost by not responding to a competing price signal. For example, an FTM battery that usually participates in wholesale energy price arbitrage is unlikely to respond to a Grid Services dispatch call if the owner expects to make more money through arbitrage than by responding to the call.

This opportunity cost depends on the DER configuration and programs in which the DER participates. Current possible FTM signals include demand charges of the wholesale distribution tariff[48], credits earned through the Clean Peak Energy Standard (CPS), and sales to the wholesale energy market. A DER responding to these calls will be incentivized to charge during the red windows and discharge during the green windows shown in Figure 21. The combination of these existing signals generally encourages charging during overnight hours and discharging in the evening.

Figure 21. FTM Hourly price signals, existing incentives



Current possible BTM dispatch signals include ConnectedSolutions calls, the Clean Peak Standard, and demand charge reductions via load flattening on applicable rates. Figure 22 shows the corresponding encouraged charging (red) and discharging (green) windows. This set of existing signals is dominated by CS calls, the window for which overlaps with the daily CPS discharge window.

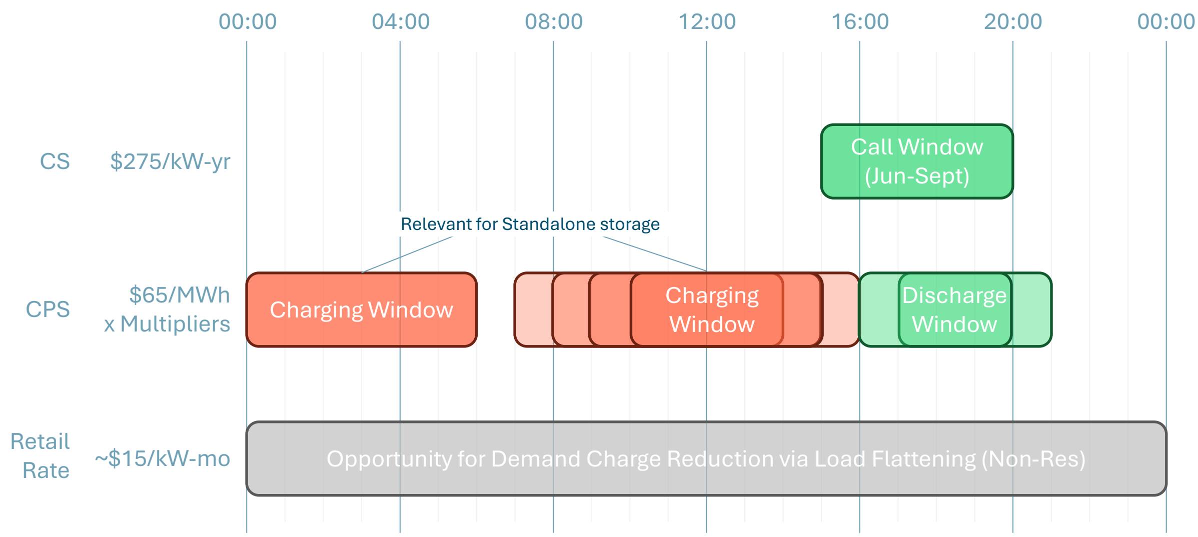
In many cases, these existing signals will complement rather than compete with Grid Services calls. When local distribution peaks align with the system peak, existing price signals will already be incentivizing dispatch at the most helpful times. However, localized peaks may not align with system peaks; the smaller geographic scale means that local weather and customer types, both of which contribute to hourly load shape variation, will not match the average weather and mix customer types observed across all of ISO-NE.

When local peak timing misaligns with the system peak, Grid Services offerings will need to offer compensation that motivates dispatch to help the local grid, even if that dispatch results in suboptimal response to other revenue opportunities. For example, an FTM DER called to support local grid need in the morning or early afternoon would sacrifice some Clean Peak credits and

[48] These tariffs, filed with the Federal Energy Regulatory Commission (FERC), dictate the price of charging standalone energy storage connected to the distribution system in each EDC. More information can be found in the following FERC dockets: National Grid: ER24-2795 and ER24-2796; Eversource: ER24-3154-000; Unitil: ER25-830

arbitrage revenues on that day. This opportunity cost would be even larger for a BTM system unable to responded to a ConnectedSolutions call due to Grid Services response.

Figure 22. BTM Hourly Price Signals, existing incentives



Appendix E. explores these dynamics in detail and quantifies the opportunity cost for two example DERs responding to Grid Services calls at different hours of the year. However, we emphasize three key takeaways here:

- Like other DER programs in the Commonwealth, Grid Services should encourage value stacking across multiple programs. Grid Services calls are expected to be infrequent relative to some other programs or daily dispatch signals, and DERs should be free to provide other services when not needed locally. In addition to encouraging efficient use of DERs on the system, this model of participation creates more opportunities for DER revenue and accordingly increases the likelihood of adoption.
- In many hours of the day, modest Grid Services incentives are enough to overcome the opportunity cost of responding to other price signals.
- It would be costly to ratepayers to inflate the incentive for Grid Services merely to overcome the signal from another DER program; dispatch incentives should be designed holistically across programs to avoid artificial inflation of incentive amounts. Some opportunity cost will persist since wholesale energy prices and retail rates are unlikely to reflect local grid needs, but sources of unnecessary competition for dispatch should be eliminated.

4.2. Compensation Mechanism Design

In addition to *how much* Grid Services offerings will pay to a DER, compensation mechanism design must outline *how* DERs will be selected, enrolled, and paid for participating. On this topic, we build upon a framework presented in Baringa's Value of DER Report.[49] This section addresses key considerations for compensation mechanisms, including feedback received from stakeholder workshops, and proposes two example mechanisms for the EDCs to explore.

4.2.1. Key Considerations for Mechanisms

Compensation mechanisms are the means by which Grid Services value is paid out to participants and encompass what is expected on either side of the transaction. Stakeholders can evaluate mechanisms based on how well they align with the overall priorities of Grid Services offerings, address the needs of both EDCs and DER owners, drive participation, deliver dependable impacts, and offer ease of implementation. Table 7 highlights key considerations by which compensation mechanisms can address each of these criteria.

Table 7. Compensation Mechanism Considerations

Criteria	Key Considerations
Creates Ratepayer Savings	• Cost-effectiveness, comparing compensation + administrative costs with value provided
Prioritizes Social Equity[50]	• Minimizes barriers to entry on an equity basis • Minimizes negative impacts to non-participants • Provides value to EJCs
Drives Participation	• Simplicity • Predictability and size of payment • Contract duration • Accessibility across segments of DER owners
Provides Dependable Impacts	• Reliability in response • Certainty in level of participation & commitment
Ease of Implementation	• Need for additional onsite equipment • Ability to execute using existing back-office tools

The Value of DER Report approaches these considerations from a different angle, breaking down compensation frameworks or mechanisms into nine different components. Table 8 lists these as described by the Value of DER Report.

[49] "The Value of Distributed Energy Resources for Distribution System Grid Services," Baringa Partners, (2024). https://www.masscec.com/sites/default/files/documents/The%20Value%20of%20Distributed%20Energy%20Resources%20for%20Distribution%20System%20Grid%20Services.pdf 8

[50] Originally presented in stakeholder workshops as Centering the EJ Experience; this was redefined based on stakeholder input.

Table 8. Components of Compensation Frameworks - Value of DER Report [51]

Component	Description
Price	Compensation value ($) placed on the allotment of a service on a fixed basis or established by participants as a market clearing price
Volume	Declare in advance the allotted size of service or take in bids from participants in an open format. This may include enrolling a volume greater than the expected need to ensure reliable response
Tenor	The length of the contract term, driven by the nature of the product or planning cycle needs
Control	A spectrum of control over DER response: natural behavior, a middle ground (contractual) or remote (full control)
Availability	Agreed period or time during which the Grid Services will be provided
Allocation	The asset selection process faces a tradeoff between cost, complexity, and depth of options considering diversity of available assets
Stacking	The hierarchy of existing products and restrictions on co-participation
Payment Basis	The basis on which compensation paid out (e.g. demand, energy provided) or the relative balance between paying for availability or active performance
Performance	How successful delivery of service is evaluated and determined

Each of these components serves as a lever that policymakers or the EDCs can adjust when designing compensation mechanisms. For example, an offering can either have a short or long tenor or require a fixed volume of capacity from any participating DER or allow for a variable response so DERs can bid in as much as they'd like when it comes down to the peak hour in which Grid Services are needed.

Referring to the balance of compensation goals discussed in Section 2.1, choosing either end of the scale involves trade-offs, and there are limits to how well any single mechanism can address multiple competing considerations. This is especially true when utility and grid needs differ from those of participants, though trade-offs can also arise among participants themselves as DER owners may have varying priorities for the offerings. Feedback from residential and commercial stakeholders in the Grid Services workshops emphasized this dichotomy, highlighting that potential participants were frequently interested in mechanisms with opposing characteristics.

A broad range of compensation mechanisms under a single umbrella for Grid Services offerings will allow the EDCs to fill the variety of distribution grid needs that exist and enable a diverse set of DERs and DER owners to participate. In the near-term, the EDCs will be able to trial multiple configurations

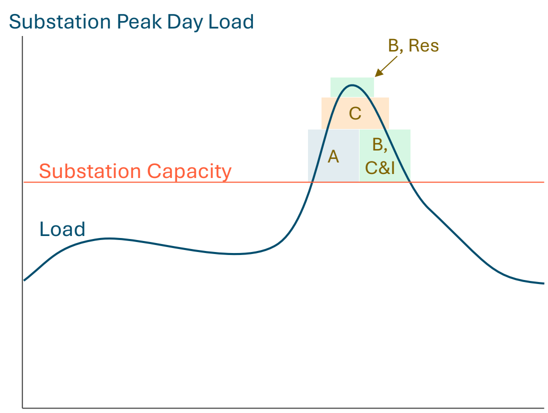
[51] "The Value of Distributed Energy Resources for Distribution System Grid Services," Baringa Partners, (2024). https://www.masscec.com/sites/default/files/documents/The%20Value%20of%20Distributed%20Energy%20Resources%20for%20Distribution%20System%20Grid%20Services.pdf

for compensation mechanisms across their respective territories and consolidate learnings as they see what can work best. These offerings should be complementary and carefully coordinated as they seek to fulfill the same core objectives and draw from the same pool of potential benefits.

As these approaches develop, the EDCs may also stack multiple options for compensation to collectively address the same Grid Services need. This will help offerings to appeal to more DER owners and allow EDCs to maximize the flexibility of Grid Services in their planning and operations. Figure 23 illustrates this stacking of multiple offerings to meet a specific need. In this example, when load exceeds the red line of available substation capacity, the EDCs rely on a combination of Grid Services offerings, shown by the colored blocks and comprising multiple DER and customer types, to fill in that need. Any single offering may not be able to address the full peak and duration of the need, but collectively they are able to do so.

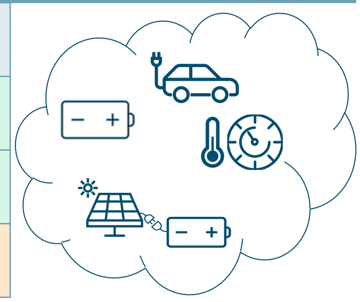
Figure 23. Stacking Grid Services Offerings

Utility Planner's Perspective



Customer's Perspective

Customer/ DER Type	Grid Services Offerings	Potential DER Participants*
Residential	Offering A	
Residential	Offering B	
Commercial & Industrial	Offering B	
Front of the Meter	Offering C	



**Eligible DERs shown are a non-exhaustive sample for illustration only*

Ensuring that offerings are a good fit for participants is also advantageous so that utilities can count on the participants to meet their commitments. For Grid Services to defer investments or avoid back-up generation costs, utilities must be able to plan around a certain level of response. Participating DERs will vary in how dependable they are in responding to frequent and regular Grid Services calls or infrequent but high-value dispatch calls that come with short notice. The EDCs may need to enroll greater numbers of the less dependable DERs to guarantee that enough resources will be available when called upon. This is also reflected in Figure 23 by the block-like nature of the offerings, where the extra capacity they provide sometimes must exceed the need. Having more options for participation can mean both that (1) more customers will be interested and able to participate – expanding the pool of DERs for EDCs to draw upon, and (2) participants will be able to sign up for offerings that better align with their capabilities – so their responses become more reliable. Building such considerations into compensation mechanisms will allow the EDCs to procure sufficient resources across the collection of offerings and ensure that compensation to DERs is commensurate with the value they provide.

4.2.2. Stakeholder Feedback and Priorities

The project partners convened a series of interactive public stakeholder workshops and complementary environmental justice focus groups. Feedback from these sessions helped shape the recommendations for valuing Grid Services and implementing offerings. Feedback can be aggregated into five key themes:

1. **Prioritizing Equity and Inclusive Participation:** Stakeholders emphasized that any new DER compensation program should not only ensure against any negative impacts, especially to EJCs and other disadvantaged customers, but also should support equitable access to participation as asset owners and recipients of the benefits. Specifically, stakeholders warned that allocation mechanisms such as first-come, first-served risk disproportionately excluding disadvantaged populations. Stakeholders also highlighted the value of including affordable multifamily housing as a group of participants within the offering. They identified this group as an untapped source for DER potential—especially through technologies like thermostat control and future solar + storage integration.

2. **Flexibility and Market-Based Design:** One concern among stakeholders was that existing programs, such as ConnectedSolutions, are too rigid, limiting participation to large and well-resourced DER aggregators. Stakeholders emphasized that the diversity of use cases across the grid cannot be addressed by a single DER type or offering structure.

   There was varied feedback on the benefits and drawbacks of using a market-based approach for Grid Services offerings. Some stakeholders recommended shifting toward a market-based approach, stating that the shift would provide more options and flexibility to both EDC grid operators and participating DERs and achieve better cost-effectiveness than traditional programs. By enabling competitive procurement and allowing price signals to dictate participation, these stakeholders suggested that this structure is best suited to maximize DER utilization and extract the most value for all parties involved by driving down costs for ratepayers. They also considered market mechanisms to be more inherently capable of incentivizing locationally targeted outcomes so that DER utilization could defer or avoid system upgrades.

   In contention with these points, there was also significant concern that market-based mechanisms would effectively prevent individual customers from participating in offerings without relying on an aggregator. Residential customers are considered less likely to be aware of or respond to market-based signals.

3. **Simplicity, Predictability, and Customer-Centric Design:** Stakeholders strongly favored compensation structures that are simple, transparent, and predictable. Specifically, performance-based payments, particularly when paired with reservation payments, were a widely supported model noted by commercial-scale entities. These approaches were valued for their simplicity and certainty. Stakeholders emphasized the need for flexibility in contract tenor. Some DER customers may prefer multi-year contracts to support financing, while others, especially residential participants, may only be able to commit to shorter terms, such as a year or even month-to-month contracts. Several stakeholders highlighted that different customer

types, even within the same class, have varying preferences that should be considered in program design. Simplicity in activation expectations was also emphasized. While aggregators may be able to respond to real-time or dynamic price signals, residential customers may only want to broadly indicate their schedules and not respond in real-time. This distinction underscores the need to tailor expectations and program designs to specific customer capabilities.

4. **Customer Autonomy and Clarity Around the Roles of Utilities and Aggregators:** Several stakeholders pre-emptively expressed resistance to direct utility or aggregator control over customer DERs, and there was clarification needed around how utilities might encourage DERs to pursue desired behaviors. Commercial and residential stakeholders generally preferred models where price signals are used to coordinate load response and suggested that overly prescriptive or utility-directed models could undermine participation. Instead, roles could be delineated such that utilities define system needs and locations while aggregators and customers decide how to meet those needs. There was some openness to aggregators or energy managers acting as intermediaries between customers and the EDCs, but others expressed concerns, citing historical wrongdoings in, for instance, marketing energy supply or community solar products, in some cases resulting in distrust of energy programs and the players involved. There was also concern that aggregators would absorb most of the incentive value intended for residential participants or that they may lock customers into predatory contracts, with greater impact on EJ and other low- and moderate-income participants. These concerns suggest a need for state oversight of vendors that interact with prospective residential participants.

5. **Location-Specific Incentives and Structural Reform:** A few stakeholders highlighted the importance of location-specific incentives and procurement processes. Simply layering new DER incentives on top of existing programs may not incentivize DERs to be deployed in new areas with low adoption. Stakeholders suggested that utilities be mandated to define needs and procure customer participation using a formalized, transparent process. One environmental advocate stakeholder suggested standard, default opt-out offerings that lower bills for low- and moderate-income customers while still delivering grid value. They also proposed letting ratepayers set automated preferences, for example turning off devices when the grid reaches hours with a certain renewable penetration. This approach reflects an appetite for customer empowerment, real-time visibility, and automation in demand-side management.

4.2.3. Example Proposed Mechanisms

To showcase these mechanisms and trade-offs, example offerings are outlined in the following figures according to six compensation components. Each component is illustrated with a scale representing the two ends of its spectrum and a grey circle indicating where the example offering may fall relative to either extreme. To reflect how the mechanisms may develop over time, the circle indicates what is currently feasible and the arrow points to the long-term technical feasibility target, where applicable. These components are similar to those outlined in the Value of DER Report and although some are not explicitly labeled (price, volume, stacking), they are embedded in the included components.

For example, with regards to activation, it is not currently feasible for all EDCs to send price signals directly to every individual customer, so relying on aggregators may make sense in the near term while EDCs develop the capability over time. Similarly, nuanced performance-based payments may have significant telemetry requirements that EDCs cannot currently meet, but they can be a key element of successful program design and represent a long-term goal.

A cross-cutting theme across these offerings is the opportunity to incorporate carve outs within the allocation component for targeted segments such as customers in EJCs, low- to moderate- income customers, and for affordable housing. This structure can help drive participation among these customer segments, helping ensure they have access to the value being generated in these programs. More broadly, carve-outs can be used for different participant types, such as customer class or technologies, to ensure diversity and balance in an offering.

To help orient the reader, the first offering outlines a familiar program, ConnectedSolutions, and how it fits into this framework. The two subsequent offerings serve as bookends, illustrating contrasting approaches: one prioritizes customer-friendliness to maximize enrollment while the other focuses on larger commitments and compensation in a “set it and forget it” model.

As the EDCs develop and trial Grid Services offerings, they must bear in mind how compensation mechanisms can complement each other and ensure wide coverage of both participant and grid needs. Just as the example offerings presented cover opposing ends of the compensation component scales, the EDCs should collaborate to deploy different mechanisms across their service territories. This will accelerate progress on near-term objectives around testing varied offerings and approaches, identifying data and process requirements, and understanding the DER market. As they begin to understand what works well, the EDCs can share these learnings across the state to refine the offerings for more effective deployment.

ConnectedSolutions - Daily Dispatch

Daily Dispatch is an existing option in the ConnectedSolutions program for commercial and industrial customers that blends moderate utility control and commitment to deliver load reduction while still encouraging broad participation.[52] Figure 24 outlines the program by compensation component:

- As the name suggests, **activation** and **availability** occur on a real time or day ahead basis.
- This dynamic element is balanced by a more moderate **tenor**, spanning one season with recurring participation.
- **Allocation** via open enrollment, instead of a competitive bidding process, helps increase uptake and engagement.

We note that National Grid plans to trial a "ConnectedSolutions Plus" style compensation mechanism that would generally align with this example. In addition to leveraging customer familiarity with the ConnectedSolutions framework, this approach has the advantage of requiring relatively little administrative overhead cost since it would operate under the umbrella of an existing program.

Figure 24: Daily Dispatch by Compensation Component

Compensation Component	Scale	
Tenor – length of any applicable contract terms	Multi-year	1-hour
Control – What level of control / influence would the utility have on participant behavior?	Natural behavior	Direct utility control
Activation – When is specific participant behavior scheduled?	At time of initial agreement	Real-time load-following
Availability – When is availability agreed upon relative to the grid need?	Multiple years ahead of need	Day-ahead / rolling enrollment
Allocation – how participating DERs may be selected	Self-enrollment – First come, first serve	Utility selects bids based on need
Payment structure – relative balance between reservation/availability and activation/performance payments (payment basis + performance)	Reservation - Set payments to all participants ($)	Performance - Issued for successful response ($/kW)

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52 Utility detail on ConnectedSolutions:
https://www.nationalgridus.com/MA-Business/Energy-Saving-Programs/Daily-Dispatch;
https://www.eversource.com/content/business/save-money-energy/energy-efficiency-programs/demand-response;
https://unitil.com/sites/default/files/2022-05/CI-DemandResponse-ProgramMaterials-Unitil-FINAL-04-04-2022.pdf

Example Offering: "Easy Enrollment"

One end of the potential offering spectrum are programs that prioritize customer preferences, such as emphasizing customer control and lower commitment, to maximize enrollment. The primary goal of this customer-centric offering would be to engage customers, gather data and learning-by-doing gains, as opposed to maximizing reliable deferral value.

Figure 25 illustrates how the offering could look according to key compensation components. Critical elements of this offering are:

- A shorter **tenor**, ranging from one season to one day, with opt-out ability and no lasting commitment.
- Significant customer **control**, potentially making little to no changes to normal behavior. This structure enables customers to see price signals and choose how to respond. Ideally participation could vary based on appliance (e.g., thermostats, V2G) and amount of reduction (e.g., different appetites for 100% vs. 50%) for additional optionality.
- **Performance-based payments** but with relatively lower compensation due to the lower commitment and higher flexibility. There would be no penalties or discounts for uncertainty, as participants are only paid for what they deliver.

Figure 25: Easy Enrollment by Compensation Component

Compensation Component	Scale	
Tenor – length of any applicable contract terms	Multi-year	1-hour
Control – What level of control / influence would the utility have on participant behavior?	Natural behavior	Direct utility control
Activation – When is specific participant behavior scheduled?	At time of initial agreement	Real-time load-following
Availability – When is availability agreed upon relative to the grid need?	Multiple years ahead of need	Day-ahead / rolling enrollment
Allocation – how participating DERs may be selected	Self-enrollment – First come, first serve	Utility selects bids based on need
Payment structure – relative balance between reservation/availability and activation/performance payments (payment basis + performance)	Reservation - Set payments to all participants ($)	Performance - Issued for successful response ($/kW)

Example Offering: Passive Value

An offering that contrasts with the one above functions as more of a "set it and forget it" type program, emphasizing more utility **control**, longer-term commitments (**tenor**) and accordingly higher compensation. The primary goal of this offering is maximizing reliable deferral value and would be more suitable for passive customers (i.e., not actively responding to price signals) and storage in particular.

Figure 26 illustrates how the offering could look according to key compensation components. Critical elements of this offering are:

- Multiple year **tenor** and **availability**, signing customers up years in advance of the grid need and locking in pricing and capacity over the long-term. There can be significant value for the utility and for participants in having this predictability.
- **Activation** at time of initial agreement, such as the season, instead of responding to capacity calls as they occur or with minimal notice. Events tend to occur at similar, expected times (e.g., summer evenings), making them relatively predictable for customers.
- **Payments** with relatively higher compensation amounts due to the longer-term commitments and higher likelihood of providing value for deferral. Given the long-term nature and utility control emphasis of this offering, the payment structure would most likely consist of fixed payments with penalties for any opt-outs.

Figure 26: Passive Value by Compensation Component

Compensation Component	Scale	
Tenor – length of any applicable contract terms	Multi-year	1-hour
Control – What level of control / influence would the utility have on participant behavior?	Natural behavior	Direct utility control
Activation – When is specific participant behavior scheduled?	At time of initial agreement	Real-time load-following
Availability – When is availability agreed upon relative to the grid need?	Multiple years ahead of need	Day-ahead / rolling enrollment
Allocation – how participating DERs may be selected	Self-enrollment – First come, first serve	Utility selects bids based on need
Payment structure – relative balance between reservation/availability and activation/performance payments (payment basis + performance)	Reservation - Set payments to all participants ($)	Performance - Issued for successful response ($/kW)

4.3. Overcoming Implementation Challenges

The EDCs will face several challenges in implementing Grid Services offerings. The challenges will vary in difficulty by location and will in part be based on the nature of the compensation mechanism. Three of the core challenges relate to technology limitations, forecasting visibility, and barriers to participation. The EDCs can overcome these challenges by making use of new tools for distributed resource planning and utilization and through thoughtful implementation practices which consider stakeholder needs.

Technology Limitations and Enablement

As EDCs pursue initiatives to modernize the grid, both the EDCs and customers must invest in the necessary communication and control capabilities to support complex pay-for-performance mechanisms. EDCs will need to accelerate investments in core technology platforms that enable visibility, coordination, and dispatch of DERs—specifically DERMS—and require participating customers to adopt enabling technology.

DERMS is a software platform that provides visibility and control of DERs and integrates with software technologies that manage the EDC-owned distribution infrastructure assets. DERMS allows EDCs to track DER behavior, plan DER response to peak events, and manage DERs in real-time. The EDCs have begun initial investment in DERMS[53] but none have deployed the technology at scale today[54]. Until an EDC has the full DERMS functionality needed to reach the DER participation levels to reliably operate Grid Services offerings, aggregators may need to expand the DER and equipment types that their platforms support. Furthermore, continuous work is needed to ensure that the EDCs data systems are compatible with aggregators' systems and that coordination is seamless to dynamically manage DERs for distribution-level constraints.

In addition to EDC operated DERMS, expanding communication and control technologies to customers is essential to facilitating participation in Grid Services offerings. The EDCs will need to communicate the importance of adopting these technologies, especially to commercial DER developers, and potentially support early investments while the market matures. To achieve Grid Services offerings, EDCs must continue to build their technological capabilities and support their customers to do so too.

EDCs may also overcome technological limitations by offering multiple options for compensation mechanisms that are available today. As an example, the technology to support a technology-neutral flexibility marketplace likely needs time to mature, but a collection of offerings targeting specific technologies may be able to dispatch similar capacity more cost effectively. This may not enable every customer to participate in their ideal offering but can at least help to enable participation by a larger number of customers.

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[53] "Massachusetts Grid Modernization Program Year 2024 Evaluation Report", Guidehouse, (2025). https://fileservice.eea.comacloud.net/V3.1.0/FileService.Api/file/aeejjajbe?9RMKqchgrKZByaH0BC3LYJJCYDN/DiDbHsUFX+Vfig6PcSxl+blU344Khxm+qpOeg0hKFj9M9l/xQR8+/8GqPvdGgrFe6XR6nglfa80wd3rxFD8G4j981M2Rna9aVTXA

[54] Each EDC has outlined its plans for DERMS and other grid modernization technology investments in its ESMP.

Forecasting Uncertainty and Visibility of Loads and DERs

A common pain point for DER programs in general and one that has hindered the adoption of location-specific offerings is the uncertainty in forecasting both load and DER growth. While some of the value of DERs stems from their incrementality and flexibility to fill in gaps in uncertain forecasts, distribution planners must have some sense of where and when load will come online and where and when DERs will be adopted to plan around these conditions and realize that value. Because Grid Services are relevant to specific sections of the distribution system, forecasts to support Grid Services must be very granular and thus are expected to have higher relative margins of error.

New utility processes and technologies, including Advanced Distribution Management Systems (ADMS) and DERMS, are helping to address this challenge by providing real-time visibility into DER behavior and load growth coupled with two-way communications. Better data collection and software tools improve planners' ability to forecast where load or DERs will be added based on customer characteristics and observed trends. Trialing the Grid Services offerings will also help to provide data on the locations and adoption of DERs. By providing a local price signal for DERs to respond to and tracking enrollment in offerings or market-based platforms, the EDCs can get a better sense of where resources are located and their capacity to potentially address other Grid Services needs.

Barriers to Participation

Stakeholders raised concerns about barriers to participation and offered ideas for how to make offerings more accessible. First, there are likely to be initial challenges in communicating the parameters and building understanding of Grid Services offerings among potential participants. Other barriers include: a lack of trust between EJ communities and utilities; concerns about affordability and cost shifting; and access to DER ownership. Program and policy levers outside of Grid Services offerings will be needed to fully overcome several of these barriers. However, there are strategies the EDCs can consider to address these barriers as they apply within Grid Services offerings:

Barriers to Participation	Potential Solutions
Steep learning curve to understand and participate in offerings	**Simplicity, Predictability, and Customer-Centric Design:** The customer, developer, and aggregator experience need to be sufficiently simple and accessible to broad audiences to enable participation. Marketing, education, and outreach best practices should be followed.[55] **Transparency around Location-Specific Incentives:** Stakeholders value location-specific information about which communities will need grid upgrades and where Grid Services compensation offerings will be offered. Early and actionable information, such as maps, will allow prospective participants to be better equipped to plan for DER development and adoption, ahead of when infrastructure projects are planned and implemented.
A lack of trust between EJ communities and utilities	**Build and Communicate through Trusted Relationships:** Trust in program administrators or aggregators is critical for community participation. Steps include: • Recognizing historic harms of the energy system and the inequitable outcomes of previous programs; • Building trusted relationships with community leaders or community-based organizations so they can be a conduit between EJCs and EDCs as they design and roll out Grid Services offerings; these relationships and dialogue should begin early, including as offerings are designed (not just implemented) so that local communities needs are reflected in the offerings; • Opening two-way communication so that EDCs are prepared to both listen to and incorporate feedback during engagements.
Affordability, cost-shifting concerns, and an assumption that the primary beneficiaries of these Grid Services offerings will be households that can afford DERs[56]	**Respond to Offering-related Cost Shift Concerns through Engagement and with Simple and Transparent Educational Materials:** Recognizing and responding to affordability, cost shifting, and other community concerns with simple and transparent educational materials that show how DER compensation is decided and how it benefits participants and non-participants can help to build trust in programs and increase both acceptance and participation. EDCs should evaluate how much Grid Services compensation and other benefits are reaching low- and moderate-income individuals and those located in EJCs, and revisit elements of identifying and designing offerings in response.
Limited access to DERs from high upfront costs (even after incentives), barriers to home ownership, and the resulting split incentive between landlords and tenants[57]	**Coordinate Grid Services Offerings with Programs Designed to Expand DER Access to Renters:** EJ communities expressed that they would like opportunities to participate in DER programs, but DER ownership and access remain a key barrier. Massachusetts has taken recent actions to expand access to DERs,[58] and as expanded incentive programs aimed at rental housing start to take shape, there is an opportunity to coordinate with Grid Services offerings. The offerings could direct incentives to specific locations on the grid and potentially offer co-deployment such that any new incentivized DERs in a target location are automatically enrolled in Grid Services offerings.

4.4. Avenues for Feedback

Eliciting and Receiving Feedback

Gathering and incorporating feedback throughout the design and implementation of Grid Services offerings is essential to the initiative's long-term success. Given the location-specific nature of Grid Services opportunities, engagement and information specific to the local community should be prioritized to maximize the success of an offering. Engaging with community representatives about customer-centric elements such as accessibility, customer satisfaction, benefits for program participants and non-participants; as well as developer and aggregator-centric elements such as data access and transparency, payment structures, and program timelines, will allow Massachusetts and its EDCs to iterate on and improve their offerings. The project partners conducted four workshops and three EJ focus group sessions to better understand stakeholder perspectives. These perspectives included thoughts on how to elicit and incorporate feedback on future program offerings.

To foster inclusive engagement, participants emphasized the need for diversifying venues for engagement, streamlining content, and prioritizing underrepresented voices in planning and implementation.

Venues for Engagement: Engagement should include opportunities for feedback that are professionally facilitated, occur outside of the regulatory process, and are specific to different programmatic offerings. Community advocates should be consulted to determine the best venue for a specific community. For example, venues could include a community center, an existing event, or a faith center. Engagement events could be timed around ESMP biannual reporting filings that include information on Grid Services progress. Ahead of facilitated sessions, the facilitation team should conduct targeted interviews with stakeholders and community leaders to help make the most of event time and focus on the topics most relevant to stakeholders. These interviews can serve as needs assessments for key stakeholders ahead of larger engagement efforts to understand either how to structure a facilitation session or what content to highlight. In tandem, feedback can continue to be elicited through surveys, public comment periods, emails, and community letters delivered through local organizations.

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[55] See, e.g., Massachusetts Interagency Rates Working Group Long-Term Recommendations, at p. 24-25. https://www.mass.gov/doc/irwg-long-term-ratemaking-recommendations/download.

[56] Demonstrating the nationwide disproportionate access to DERs, a 2019 study showed that there are racial and ethnic disparities in solar deployment. In Massachusetts there are differences in solar ownership versus solar leasing along racial and economic lines such that low-income communities of color tend to have lower financial returns from solar. Sunter, D., Castellanos, S., & Kammen, D., "Disparities in rooftop photovoltaics deployment in the United States by race and ethnicity"., Nature Sustainability, (2019). https://www.nature.com/articles/s41893-018-0204-z

[57] The split-incentive gap refers to how a landlord finances energy upgrades, but tenants benefit from them. The result can be that renters have less access to energy upgrades.

[58] In 2024, the Massachusetts DPU updated the net-metering program, which is expected to unlock additional distributed energy generation, and in The Massachusetts 2025-2027 Energy Efficiency and Decarbonization Plan, Mass Save began structured incentives so that both home owners and renters can access benefits.

Content: Engagement opportunities should provide digestible, appropriately scoped content to enable more effective stakeholder engagement. Throughout the engagement process, stakeholders requested more transparency from EDCs and more detailed information about the location of planned offerings and their estimated impacts.

- **Local maps and impact estimates:** Sharing visuals of where offerings will be rolled out, what the projected customer impacts are, and who is eligible promotes transparency and accountability. The EDCs have shared some of this information in the ESMPs, but they may need to better publicize or present it in a way that is more digestible for potential Grid Services participants when launching specific offerings.
- **Plain language and translation:** Content should explain core concepts (like "distributed energy resource" or "smart inverter") in accessible language and be translated into locally spoken languages.

Prioritizing Underrepresented Voices: Communities that have historically been disadvantaged by the energy system or excluded from decision-making are important to center in the design of stakeholder engagement. Collaborating with trusted community partners to design engagement that is culturally relevant can enhance meaningful participation. Honorariums, including food and childcare (if in-person), for those that participate in small group feedback sessions can also reduce the burden of participation and increase access to information and decision-making processes.

Collecting stakeholder feedback will allow Massachusetts and its EDCs to improve the Grid Services offerings by iterating to incorporate stakeholder perspectives throughout the lifecycle of programs.

Recording and Incorporating Feedback

It is important to be transparent about how feedback will be incorporated into program design. Providing feedback requires an investment of time and resources, oftentimes from stakeholders who are engaged in several related engagements and initiatives. Therefore, publicizing feedback, EDC responses, and EDCs' plans to incorporate feedback can help build trust with stakeholders that their investment of time is met with due consideration, which can engender continued engagement and feedback. Examples for this kind of transparency include:

Responding to comments: The full Stakeholder Feedback Tracker included as a spreadsheet attached to this report can serve as an initial model for this. The Tracker summarizes each piece of feedback received, the source and medium through which the feedback was received, and how feedback was addressed or incorporated in the study.

Published criteria for decision making: For example, the Department of Energy Communities Local Energy Action Program (LEAP) publishes equity and technical scoring criteria ahead of time so applicants understand how input, including stakeholder feedback, will be weighted.[59]

[59] "Communities Local Energy Action Program (LEAP)", U.S. DOE, (2023). https://www.energy.gov/sites/default/files/2023-10/Communities-LEAP-Cohort-2-Informational-Webinar-Slides_10.5.pdf

5. Long-Term Implementation

Looking into the future beyond 2030, the Commonwealth will better understand how decarbonization efforts, especially electrification and DER adoption, are unfolding. We will also have more insight into the impact of new and more flexible loads on the electric grid. We will see what emerging technologies have taken hold, how markets and costs have developed, and how industry practices and processes have evolved to meet a changing environment. We imagine that five years from now may still be a time of rapid change and uncertainty in some areas. However, by that time, Massachusetts will also have further practice integrating DERs and years of experience with Grid Services to draw upon. To prepare for the impacts of load growth and DERs further into the future, the Commonwealth and EDCs must plan proactively to take advantage of knowledge built during initial offering periods and refine Grid Services offerings to consider evolving conditions.

Objectives for Long-Term Implementation

Just as in the near-term, long-term objectives for Grid Services offerings should be guided by the overall Grid Services vision discussed in Section 1.1. Where near-term objectives focus on learning by doing, long-term objectives should consolidate those learnings to advance the vision and ensure offerings will be sustainable into the future.

Long-Term Objectives:

1. **Adapt planning processes to maximize potential for ratepayer savings through investment deferral.** For Grid Services offerings to provide meaningful value to ratepayers, EDC planning processes must evolve to better integrate DERs and Grid Services benefits early on and across a broad set of circumstances. EDC planning teams highlighted early in the study that deferral of investments can only occur during the tight window after a future grid need has been identified and valued but before it is necessary to begin building traditional infrastructure solutions to meet the need in time. During that window, EDCs must be able to understand the capacity of Grid Services available to reliably meet that need and adapt their planning to include this. Process enhancements to increase the potential for Grid Services value therefore include: improving forecasting methods for load and DER growth to expand the planning window; finding ways to incorporate additional deferral value through optionality or other means; and seeking to identify more instances where DERs can offer a cost-effective alternative to traditional solutions. We expect that deferral can increasingly result in longer-term deferral and avoidance as Grid Services offerings mature.
2. **Continue to leverage Bridge-to-Wires Grid Services solutions to prudently accelerate policy-driven load growth.** As previously noted, we expect the frequency of Bridge-to-Wires scenarios to decrease as planning and forecasting processes evolve to better predict grid needs with ample lead time for wires or deferral solutions. Nonetheless, some load growth will continue to occur in large steps that are difficult to predict. In these cases, Bridge-to-Wires solutions should continue to be explored, but with the same caution as today regarding the potential for rate impacts. For scenarios that allow for acceleration of

the Commonwealth's energy goals such as end-use electrification, the state may also explore funding mechanisms outside of the general rate base to be able to provide motivational incentives without increasing electric rates.

3. **Facilitate equitable access to participation and benefits from Grid Services offerings.** Equitable access to DER adoption is a need that is not specific to Grid Services. EDCs and the Commonwealth should evaluate DER adoption in EJCs and iterate on strategies to achieve equitable rates of adoption in those communities. Without equitable access to DERs and DER ownership, there cannot be equitable access to Grid Services offerings. Specifically within Grid Services offerings, EDCs should continue to evaluate how much Grid Services compensation and other benefits are reaching low- and moderate-income individuals and those located in EJCs. The EDCs should also consider new ways to value EJ benefits from Grid Services. Depending on the success of initial offerings and the community response, the EDCs can begin to prioritize EJ locations for new offerings.
4. **Provide efficient compensation mechanisms built on the feedback and observations from trial offerings.** Once the EDCs understand what works well for participants and for the grid, they must act on it, scaling as appropriate and pursuing leaner, more cost-effective implementation.
5. **Use growing experience identifying and executing on deferral opportunities to reevaluate the role of Grid Services compensation as a driver of dispatchable DER adoption.** The localized and ephemeral nature of deferral opportunity results in too much uncertainty for DER owners to count on Grid Services compensation in adoption decision-making today. However, future improvements in distribution forecasting coupled with higher resolution system data should increase the frequency of deferral opportunities and the predictability of them. Equipped with this information and having learned what to expect from Grid Services calls through years of experience, DER owners may begin to regard Grid Services compensation as a more certain component of their revenue stack.

In service of these objectives, we outline strategies to measure the success of Grid Services offerings, methods to promote continued utility action, and milestones for re-evaluating and updating the offerings.

5.1. Measuring Success

As the EDCs design, implement, and scale Grid Services offerings, they must assess how the offerings measure up against their expected outcomes and whether they are furthering the vision for Grid Services. This measurement will be critical for developing offerings in the long term but should begin on day one. We recommend evaluating Grid Services offerings using metrics that describe a benefit-cost analysis of the offerings, the reach of the offerings in terms of Grid Services potential and participation, and more qualitative stakeholder feedback. The most actionable metrics will be those which are both objectively quantifiable and within EDC control, though others may also be useful especially for the sake of transparency or to provide insight on stakeholder perspectives. These latter metrics are intended primarily for improving offerings and understanding potential customer response rather than evaluating the performance of the EDCs.

5.1.1. Benefit-Cost Analysis

A benefit-cost analysis (BCA) is designed to evaluate whether the benefits of a program outweigh the costs. Initial BCAs for specific Grid Services locations can be developed using the valuation framework described in Section 3.1, plus estimates for implementation costs and expected DER response. Once the Grid Services offerings are implemented, new BCAs will need to be conducted based on actual data and metrics to understand whether the offerings are beneficial and how they can be amended to create greater net benefits.

The first and broadest category of metrics for Grid Services supports a BCA comparing the deferral and Bridge-to-Wires value with overall costs of implementation. These metrics will evaluate both whether ratepayer savings are being realized and the accuracy of up-front expectations or targets.

On the benefit side of the equation, metrics are largely a measurement of the same inputs discussed in Section 3 and the valuation model.

<u>In deferral scenarios, key benefits metrics by project include:</u>

- *Years of successful deferral for infrastructure investments*
- *Estimated deferred cost of the investments*

<u>In Bridge-to-Wires scenarios, key benefits metrics include:</u>

- *Estimated avoided costs of running backup generation or storage*
- *Estimates of reductions to load interconnection wait times at* Bridge-to-Wires *locations*
- *Have EDC grid operators been able to effectively incorporate DERs in operations?*
  - This may initially be a more qualitative and subjective assessment answerable by the EDC teams, but still useful to survey for improving DER integration
- *Degree of dependable response to calls for DER dispatch (by offering and participant type)*

As applicable, the distribution of benefits should be evaluated by participant type and location (e.g., within an EJC, and to low- and moderate-income households). In addition to key metrics above, metrics for non-rate impacts can be used to evaluate the broader impacts of Grid Services offerings.

On the cost side, it is especially important to begin tracking costs early on, because it can be difficult to accurately account for certain cost categories, such as administrative labor and overhead, after the fact. There is a balance to be struck regarding the additional administrative burden of tracking costs for individual projects; but, at a minimum the EDCs should establish clear budgets specific to Grid Services offerings.

<u>Cost metrics for all scenarios include</u>:

- *Compensation paid out, by Grid Services project and year, and by participant type and location (e.g., within an EJC, or to low- and moderate-income households)*
- *Cost (labor, overhead) for valuation studies*
- *Sunk costs of infrastructure already invested (if not subtracted from benefits)*
- *Cost (labor, overhead) for offering design*
- *Cost (labor, overhead) for offering administration and outreach*

To reflect core outcomes for these offerings, the EDCs should record the number of projects that have been successfully deferred or locations where earlier customer interconnections have been supported by Bridge-to-Wires, and net benefits accrued to ratepayers.

5.1.2. Grid Services Offering Potential

Information regarding the number and locations of Grid Services opportunities that have been evaluated and the value that each is expected to provide can help stakeholders to understand the availability and potential impact of Grid Services offerings.

<u>Metrics to evaluate Grid Services offering potential:</u>

- *Number of eligible Grid Services locations, by total value of deferred or avoided cost*
- *Number of locations with local grid constraints that have been evaluated for Grid Services offerings*
- *Proportion of distribution system investment projects that are eligible for* Grid Services *offerings*

For each metric, the distribution of locations and offerings should be evaluated in terms of whether it is within an EJC or not. While Grid Services opportunities are inherently location-specific and determined by grid needs, evaluating the distribution of opportunities can improve transparency and identify unintended biases or outcomes.

5.1.3. Participation

Metrics around participation can help indicate the success of outreach strategies, whether offerings appeal to specific customer segments, and the makeup of the participant base.

<u>General participation metrics:</u>

- *Number of participants by customer type and capacity of DERs by DER type enrolled in Grid Services offerings, similarly matrixed by the offering compensation structures*
- *Capacity of DERs enrolled relative to capacity needed for a specific offering*
- *Number of participants and capacity of DERs in participating in Grid Services offerings relative to participation in other offerings by other DERs in Grid Services eligible locations*
- *Change in each of the above over time*

<u>EJ-specific participation metrics:</u>

- *Number and capacity percentage of participants that are designated as EJ*
- *Number and capacity percentage of EJ participants relative to target/expected share used in calculating compensation*
- *Number and capacity percentage of EJ participants compared to total EJ population where the Grid Services need is located*
- *Rate of DER ownership among the EJ population*
- *Change in each of the above over time*

5.1.4. Stakeholder feedback

Stakeholder feedback can provide insight into the *how* and the *why* behind the numbers of other metrics. EDCs should regularly solicit open stakeholder input, as discussed in Section 4.4, and seek to answer questions such as

- *Do participants feel satisfied with* Grid Services *offerings? Why or why not?*
- *How can existing offerings or processes be improved?*
- *What aspects of offerings are most important to participants?*
- *How can the EDCs reach a wider audience for the offerings and what types of education and outreach are needed?*

This feedback, alongside the other metrics listed, should be tracked over time and may be shared through the EDCs bi-annual reporting process for the ESMPs or on an annual basis in the longer term.

5.2. Regulatory Evolution to Promote Grid Services

Traditional cost of service regulation, in which shareholders recover a rate of return on capital spending, creates a disincentive to employ Grid Services solutions. To better align utility financial incentives with public goals, the Commonwealth has already deployed several mechanisms including revenue decoupling, capital trackers, and Performance Incentive Mechanisms (PIMs). To compel the EDCs' continued engagement in seeking and selecting Grid Services solutions, the DPU may consider PIMs tied to some of the metrics for success listed above. As an example, a load interconnection PIM may persuade a utility to seek out Bridge-to-Wires opportunities. We do not explore these options in detail here but make two observations:

1. PIMs should tend towards generality. This allows for clear connection to policy goals and avoids constraining utility approaches in a way that may hamper efficiency. For example, a PIM focused on local air quality would allow Grid Services to be part of the solution but not preclude other apt solutions.
2. PIM incentive levels should be considered very carefully and included in cost-benefit analysis. Dollars collected to fund a PIM erode the ratepayer savings from Grid Services. Much like the incentives offered to DERs, the best incentive offered as a PIM is the smallest amount that still promotes the desired utility action.

5.3. Milestones for Re-evaluating and Updating Offerings

Grid Services offerings should evolve over time alongside changes in the distribution grid, responding to learnings from implementation, and expanded capabilities of DERs and EDCs. Some checkpoints, or milestones, for re-evaluating offerings will occur naturally as new grid need locations are identified and as Grid Services offerings are assigned to those locations. Many of these revisions will concern changes to costs or inputs into the valuation methodology. More structural changes will be needed as well, for both the valuation methodology and compensation mechanisms.

Broader considerations for implementation, such as how to conduct outreach and how to engage with communities, should be constantly evolving based on feedback received.

Project-by-Project Updates

Each time a new Grid Services need is identified, and an offering is developed, grid planners should review and update individual inputs to the valuation calculation. Deferred investment costs are inherently project-specific, as is the capacity need forecast, which should be updated to reflect any changes to the distribution forecast. Similarly, in Bridge-to-Wires scenarios, the cost of deploying backup generation or storage solutions should be reassessed for each potential Grid Services location. This may entail requesting quotes from suppliers and reviewing current fuel and maintenance costs as applicable.

Other inputs into the valuation methodology may not change every time a Grid Services need is identified. Financial inputs for the net present value calculation, equipment cost inflation, and marginal system line losses all fall into this category, as they are not project or site specific. However, distribution planners should still regularly review these inputs to ensure that they align with the most recent studies or public filings.

Updates to Valuation Methodology

We recommend that the valuation methodology itself be revisited on a regular basis to determine whether specific approaches can be improved or whether new categories of costs or benefits can and should be quantified to inform the Grid Services value. For example, as forecasting and planning evolves, this may enable the inclusion of the optionality value. While more well-established bulk grid valuation tools such as the New England Avoided Energy Supply Costs are updated less frequently, annual review of valuation methodologies may be appropriate as the EDCs launch offerings and gather data on impacts. In the longer term, the cadence can be relaxed to longer intervals once there is more confidence in the established processes.

Improvements to Distribution System Forecasting

Current distribution system forecasting practices rely on reactions to historical data and load interconnection requests. New distribution forecasting methods improve on this outdated paradigm by incorporating policy-compliant projections of electrification and using multiple scenarios to sweep out a range of uncertainty. The emergence of these new methods and tools to improve the granularity and accuracy of distribution-level forecasting will enable rapid expansion of Grid Services. These advances will help to identify opportunities for deferral and will present clearer specifications of deferral needs.

Improved forecasting will also allow planners to get ahead of potential Bridge-to-Wires solutions with timely identification of infrastructure needs, and sometimes corresponding identification of deferral opportunity. With reductions to the uncertainty and unexpectedness of rapid load growth that drive Bridge-to-Wires scenarios, the need for Bridge-to-Wires solutions will decline. However, long lead times and newly imagined ways to leverage DERs as quick solutions will likely keep the Bridge-to-Wires use case from disappearing entirely.

Updates to Compensation Mechanisms

The first layer of refinement for updating compensation mechanisms involves the level of compensation provided for each offering. As discussed in Section 4.1, compensation may be set anywhere between an effective price ceiling or floor, dictating what share of the total Grid Services value goes to participants versus ratepayers. Each time an offering is created at a new location, the EDCs must consider what that balance should be, taking into account the specific conditions for the grid need and the level of response observed in comparable locations. It may take multiple trials and input from stakeholders to understand the best approach to arriving at that balance. As more DERs come online, the level of compensation required to attract participation will generally trend downward. Increased awareness about the offerings and improvements in simplicity of participant processes will accelerate a decline in the level of required compensation. In the long term, this will allow a greater share of the total Grid Services value to be reserved for decreasing electricity costs for ratepayers.

EDCs should additionally pursue further structural refinement of the compensation components discussed in Section 4.2.1. In the near term, unique configurations of compensation components should be considered each time a new offering is created whether adjustments are slight or significant. It is valuable to have variety in compensation mechanisms early on so that the EDCs can understand what is viable and stakeholders can react to different options. As Grid Services offerings approach the five-year mark and the 2029 update to the ESMP filings, the EDCs should take advantage of this milestone to reassess their offerings collectively and solidify more standardized mechanisms for future offerings. These updates can involve combining or stacking offerings and should consider past EDC and stakeholder experiences with individual offerings—adopting approaches that have been effective in the near term. Standardizing offerings will enable more efficient implementation and a streamlined, consistent participant experience.

The most significant long-term update we recommend is a holistic evaluation of DER programs and offerings in the state. Considering the full set of grid benefits that DERs can provide, including bulk grid and location-specific impacts, will reveal the most cost-effective dispatch behavior for grid-connected resources. Subsequent to this evaluation, the Commonwealth and EDCs may consider creating DER compensation offerings which span the full range of grid value streams, where the price signals are dictated by whichever value stream is highest priority for the grid at a given time of day or year. This potential stacking of signals has also been discussed within the Baringa Value of DER Report.[60] For location-specific values like Grid Services, compensation may simply be low or zero where the associated grid need does not exist. To the extent feasible, the current DER incentive programs and Grid Services offerings should merge to allow for sending the simplest cost-based signal to guide DER adoption and dispatch. However, multiple offerings with varied configurations may still be necessary to allow participants to choose whichever structure appeals most to them.

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[60] "The Value of Distributed Energy Resources for Distribution System Grid Services," Baringa Partners, (2024). https://www.masscec.com/sites/default/files/documents/The%20Value%20of%20Distributed%20Energy%20Resources%20for%20Distribution%20System%20Grid%20Services.pdf

A holistic approach would also address a range of concerns raised by EJ and other stakeholders, providing more transparency into cost shifting across multiple programs, and simplifying offerings from a participant perspective. Such coordination can save EDCs and ratepayers money by consolidating program management and outreach. National Grid is putting this into practice by trialing one of their initial Grid Services offerings as a "ConnectedSolutions Plus" style compensation mechanism. Under this potential offering, participants would have the option for Grid Services dispatch requirements and incentives added onto the existing ConnectedSolutions compensation in areas where Grid Services needs are identified. In the long term, the EDCs and other program administrators can coordinate and evaluate the collective grid benefits of multiple programs. The 2029 ESMP filing update presents an opportunity to initiate this cooperation, though improved coordination may also be considered each time an existing DER program is up for renewal or re-evaluation.

Evolving Policy Objectives for the Commonwealth

Broadly, states and utilities will continue to adapt decarbonization strategies and the grid planning that supports them to the ever-changing context set by several uncontrollable and currently uncertain factors. Load growth, equipment costs, public opinion, support from the federal government, and other factors fluctuate in ways that all but guarantee a decarbonization plan formed today will differ from one formed in five years. While there are no changes to policy objectives that should impact the core objectives of Grid Services, they may marginally impact characteristics of specific offerings. For example, increased emphasis on affordability could reduce the state's willingness to allow compensation above the recommended ceiling. Alternatively, changes in federal support or equipment costs may affect policy tactics for decarbonization and what types of DERs will be most available to participate in Grid Services offerings. Accordingly, nuances or priorities of Grid Services enablement may change.

6. Conclusion

As the electricity grid evolves to serve new loads and technologies, distribution grid operators have an opportunity to draw upon the growing population of DERs to provide distribution Grid Services. With existing infrastructure under strain and costs rapidly rising, the collective impact of Grid Services has the potential to translate to significant ratepayer savings. A granular, project-specific approach to identifying that value can ensure that compensation offerings send the right signals to realize those benefits. These offerings have the potential to provide utilities with a tool for managing rapid change in the distribution grid and inherent uncertainty, and provide local system benefits. In turn, Grid Services can reduce ratepayer costs and improve affordability, and can be designed to simultaneously advance equity and environmental justice.

The study provides methodologies for calculating the value of Grid Services in investment deferral or Bridge-to-Wires scenarios, recognizing rate and non-rate impacts. Using this value as a guidepost, we propose a compensation design framework which prioritizes ratepayer savings and environmental justice. Through collaboration with state agencies and the EDCs and incorporating stakeholder feedback from public workshops and EJ focus groups, we present a roadmap for the near-term and long-term implementation of Grid Services offerings. As the EDCs converge on their approaches to Grid Services offerings, they will be able to build upon the work done in this Grid Services Study and the experience they gain through near-term trial offerings to maximize the long-term use cases and benefits of Grid Services.

Appendices

Appendix A. Stakeholder Feedback Tracker – Summary Table

The following presents a condensed summary of input received from stakeholders over the course of this study. A complete copy of the feedback tracker can be found as an Excel workbook attachment to this report and on the Massachusetts Clean Energy Center Grid Services Study website.

Theme	Feedback
Stakeholder Engagement Process	• EJ organizations are frequently overburdened by engagement requests and may benefit from targeted participation structures. Honorariums, scheduling clarity, and support for group-based participation best practices for conducting targeted stakeholder outreach. • Stakeholders want to see how their feedback is incorporated in decision-making, and further that applicable feedback is shared across state agencies to help avoid duplicative engagement efforts.
Barriers to Participation	• EJ communities face significant obstacles including lack of capital for DER projects, technical complexity, and low homeownership rates. Achieving equitable DER adoption requires targeted strategies to engage landlords, build trust and awareness, and support adoption in EJ communities. • Traditional programs have excluded EJ communities due to a lack of adoption or awareness. Mechanisms like EJ-specific shares of enrollment or enhanced incentives could improve inclusion. • Low trust: Communities may be wary of utility programs and/or aggregators due to past experiences of shouldering disproportionate costs for energy programs, and lack of direct access to benefits and/or predatory experiences.
Valuation	• Programs should avoid cost shifts onto low-income customers. • Valuation frameworks should include non-energy benefits such as air quality improvements.
Compensation	• Rigid structures in existing programs have limited participation to large DER providers; market-based approaches could increase flexibility and effectiveness but would limit individual customer participation. • Prioritizing certainty and simplicity in offerings could increase participation from both developers and residential participants.
Implementation	• Coordination with existing programs is essential to avoid redundancy and leverage existing DER momentum. Program design should allow for compensation stacking and ensure high enough payment levels for meaningful participation. • Effective outreach and flexible structures are key to enrollment, especially for underrepresented customer segments.
Implementation - EJ Focus	• DERs have the potential to empower communities, but concerns exist around unequal access and the risk of predatory aggregator practices. • Tailored outreach materials (case studies, fact sheets, translated documents), ideally coming from trusted sources are needed for different communities. • Engagement must move beyond tokenism and ensure feedback is genuinely integrated into program design.
Roadmap	• Long-term planning must provide clarity on grid needs, equity impacts, and integration with other programs. • Near-term focus should include identifying barriers to adoption or participation and expanding DER-enabling infrastructure. • Ongoing outreach should be inclusive of all DER providers, with close tracking of participation patterns and dropout causes.
Other	• Community members expressed concern about representation, trust, and follow-through from previous planning efforts. • Questions about whether utility business models truly incentivize DER adoption. • Support for integrated, equity-focused electrification strategies that reduce fossil fuel use and build behind-the-meter capacity, including tie-ins with retail rate reform.

Appendix B. Grid Services Study Primer

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Massachusetts Grid Services Primer

December 12, 2024

Developed by E3 and RMI in support of the Massachusetts Grid Services Study, sponsored by the Massachusetts Clean Energy Technology Center in collaboration with the MA Department of Energy Resources, Attorney General's Office, and Eversource, National Grid, and Unitil.

Primer Contents

1. Introduction to DERs and Grid Services

1.0. Purpose of this Study

This Massachusetts Grid Services study is intended to delve into the value that non-utility-owned energy resources may be able to provide to the electric distribution grid and inform the design of potential programs or mechanisms to compensate those resources. While there are a wide range of benefits that different energy resources may provide to the broader electric grid, for the purpose of this study, “Grid Services” will refer specifically to the benefits provided by distributed energy resources (as defined below) to the local electric distribution system. This primer is intended as a reference guide to accompany the early stages of the study and provide stakeholders with context for the discussion and public-facing workshops to follow.

1.1. Distributed Energy Resources (DERs) and their Benefits

Distributed energy resources (DERs) are technologies connected to the distribution grid which can generate electricity or reduce or shift grid loads. DERs include energy efficiency, demand response, distributed solar PV, distributed energy storage, and electrification loads such as from EV and heat pumps. DERs can provide a range of services to the electric grid, including generating, storing, and modulating the use of electricity, among others. DER grid services can play a critical role in meeting local demand, easing localized constraints, and improving reliability. DERs have the potential to provide these services more quickly, at less cost, and with fewer community burdens than traditional grid infrastructure solutions. In addition to these services to the electric grid, DERs can also help to achieve societal benefits and policy goals such as a reduction in greenhouse gas emission or other hazardous air pollutants.

DERs include a vast array of customer-sited technologies that can interact with the electric grid in some way beyond simply using or exporting electricity whenever they are plugged in and turned on. DERs are often categorized based on how they are used. For example, DERs like rooftop or community solar allow customers to generate zero carbon electricity for their own consumption or export to the grid, while other DERs including electric vehicles (EVs), smart thermostats, or battery energy storage systems (BESS) grant users the flexibility to shift their energy demand to different times of the day, potentially reducing strain on the electric grid. Any given DER might have multiple uses, and it is up to the DER owner and/or grid operator to make the most of those varied benefits.

Rate-Related Benefits: Avoided and Deferred Costs

When it comes to thinking about the benefits that DERs can provide to the electric grid, it can be useful to start with the benefits that directly impact costs shared with other electric customers. If you can reduce these costs – such as for building new generation or infrastructure – you can reduce the rates that everyone must pay. Even if you only defer, or delay, the need to build that infrastructure, there is value to an electric company and its ratepayers in providing temporary savings. For the purposes of this study, these benefits are therefore referred to as Avoided and Deferred Costs.

For the electric distribution company (EDC),[1] as the distribution grid operator, any DER alternative must be as reliable as the traditional solution to enable the associated Avoided and Deferred Costs. Real time grid operators must be able to call upon DERs when and where it is needed with complete confidence that the DER will respond and perform when activated (e.g., Wi-Fi thermostat will adjust, managed charging will initiate, battery will discharge). The EDCs are building enabling technology for DER visibility and remote management. This technology is expected to interface with customer systems, based on agreed upon parameters.

Non-Rate Impacts

It is also important to realize the impacts of a DER beyond those that alter the rate electric customers pay. In addition to impacting the cost of the electric grid, DERs and policies surrounding them may result in either positive or negative impacts for society, including the reliability of the grid, pollution that is created or avoided but not fully factored into electric rates, or economic growth. A subset of these may also be tied to or recognized as grid services and evaluated in this study.

Who Is Impacted?

Just as the types and magnitude of impacts from DERs should be evaluated, policies and program design must also consider who experiences these impacts. DERs may provide direct benefits to the owner, rather than the grid as a whole. In these cases, since the customer is already seeing a benefit, they may not need additional incentives from the electric company. On the other hand, some non-rate impacts that similarly do not show up as obvious benefits for the electric grid might still benefit society as a whole and may be worth recognizing.

Environmental Justice

Tied to the question of *"Who is impacted by DERs and related policies?",* a key consideration in our study is how environmental justice may be considered in evaluating the grid services DERs provide. Environmental justice (EJ) populations have historically faced the greatest harm from air pollution, climate change, and other negative impacts that may come from energy infrastructure and energy generation. Additionally, these populations often spend a high share of their total income on energy. At the same time, disadvantaged or low-income populations typically have limited economic resources to adopt DERs, so without incentive or rebate programs targeted to these communities they may be less likely to enjoy the localized or participant benefits. We will seek to better understand how these concerns may be addressed. As a part of this study and the stakeholder process, we especially welcome feedback from and involvement by representatives of EJ populations to ensure they benefit from the clean energy transition.

[1] The electric distribution companies referred to as part of this study include Eversource, National Grid, and Unitil. They may also be referred to as "utilities" or "electric companies".

1.2. What are Grid Services?

"Grid services" can broadly refer to services that help grid operators and planners manage the electric system, including services related to the regional electric generation capacity, transmission network, and local distribution systems. The focus of this study is to explore ways to value and compensate customers for providing *distribution* grid services, which can be highly location-specific in nature. For this reason, "Grid Services" and "Distribution Grid Services" may be used interchangeably in this primer and study effort moving forward.

As a part of the Electric Sector Modernization Plan (ESMP) process, the Massachusetts EDCs identified the potential for DERs to offer value and flexibility in addressing areas of need on the distribution system. The primary sources of value identified by the EDCs include: (1) avoiding or deferring investment in traditional grid infrastructure; (2) avoiding the need for risky and costly mitigations to address local overloads, such as portable generators; (3) providing grid operators with another "tool in the toolbox" to respond to reliability and power quality concerns on the electric system to optimize the system in real time.

Within their ESMPs, the EDCs have put forth several initial suggestions for how this grid services value might be determined and compensated. This study intends to build upon those ideas in a collaboration between the Massachusetts Clean Energy Technology Center (MassCEC), the EDCs, the Department of Energy Resources (DOER), and the Attorney General's Office (AGO). This effort is intended to include several opportunities for the involvement of a broad group of stakeholders. The ultimate outcomes of this effort will include:

- A Massachusetts-specific, statewide compensation framework for DERs providing location-specific grid services to the distribution grid, including specific attention to understand the value that DERs can provide in EJ populations.
- A roadmap describing steps to establish and implement both near-term and future grid services programs. This roadmap will detail ways to access value from customer-owned DERs which are both useful and reliable for grid planning, as well as deliverable from a customer experience perspective.

Over the coming months, MassCEC and its collaborators will host a series of 4 workshops to provide transparency to stakeholders and solicit public input and participation in this effort.

1.3. Compensation for DERs

DER programs use a variety of compensation mechanisms to recognize the benefits that DERs provide and to support further adoption. This compensation may take different forms, ranging from up-front rebates to pay-for-performance bill credits. The level of compensation may be determined based on the grid service needed at a specific location, specific types of value a DER provides to the grid, or simply based on what price point is expected to incentivize a certain amount of program participation. Since there are many overlapping compensation frameworks in the same EDC's service territory, it is important to consider how they intersect to ensure that DERs are being fairly compensated and that customers are given clear price signals to support beneficial DER adoption.

DER programs in Massachusetts

The Commonwealth of Massachusetts, in collaboration with the EDCs, hosts several existing programs to support the growth of DERs.[2] DERs may also be eligible to participate directly in wholesale markets. A few of these programs are listed as examples below:

- **ConnectedSolutions**: The ConnectedSolutions program offers financial incentives to homeowners and businesses for participating in demand response initiatives, like reducing energy use during system peak times or enrolling smart devices to help balance the grid.
    - Additional Information:
    - https://www.eversource.com/content/residential/save-money-energy/energy-efficiency-programs/demand-response/battery-storage-demand-response
    - https://www.eversource.com/content/residential/save-money-energy/energy-efficiency-programs/demand-response/smart-thermostat-demand-response
    - https://www.nationalgridus.com/MA-Home/Energy-Saving-Programs/ConnectedSolutions
- **SMART**: The SMART program provides financial incentives to homeowners, businesses, and organizations for installing solar and energy storage systems, offering payments based on the amount of energy produced. The program supports both residential and large-scale solar projects with incentives that decline over time as targets are met.
    - Additional Information:
    - https://www.masmartsolar.com/
    - https://www.eversource.com/content/residential/save-money-energy/clean-energy-options/solar-energy/smart-program
    - https://unitil.com/ways-to-save/solar-private-generation/smart-program
- **Clean Peak Standard**: The Massachusetts Clean Peak Energy Standard is designed to provide incentives to clean energy technologies that can supply electricity or reduce system-wide demand during seasonal peak demand periods established by DOER.
    - Additional Information:
    - https://www.mass.gov/clean-peak-energy-standard
    - https://www.masscec.com/clean-peak-standard-cps
- **Net Metering**: The Net Metering program allows distributed energy generation owners to earn credits for the excess electricity they produce and send back to the grid, which can offset future energy bills. These credits are based on specific components of the retail rate.
    - Additional Information:
    - https://www.mass.gov/info-details/net-metering-guide
    - https://www.eversource.com/content/residential/save-money-energy/clean-energy-options/solar-energy/net-metering-defined
    - https://unitil.com/ways-to-save/solar-private-generation/net-metering

[2] We note that while these programs are specific to the EDCs, several MLPs have similar offerings aiming to achieve similar ends in their own service territories. The MLPs are not the subject of this study.

2. Glossary of Acronyms and Industry Terms

Term	Definition
ADC	Avoided and Deferred Costs, a means for valuing a resource based on its ability to delay or avoid the need for making investments in additional utility grid infrastructure
AMI	Advanced Metering Infrastructure, a modern system of utility meters, sometimes referred to as "smart meters"
Bridge to Wires (B2W)	The use of DER dispatched by a utility to address a present or imminent reliability need on the distribution system prior to the completion of a wires-based solution
BTM	Behind-the-Meter, referring to a resource that is located on the customer's side of the electric meter, indicating that the resource may be first drawn upon to serve customer needs, rather than utility needs; see FTM (Front of the Meter)
Community Solar	Community Solar refers to solar generation facilities that provide electricity or bill credits to multiple utility customers.
Cost Shift	A phenomenon in utility rates increase for a given customer class to pay for costs incurred by another class
CS	ConnectedSolutions, a behind-the-meter demand response program in Massachusetts that provides and incentive to customer who reduce their load during system-wide peak events
Clean Peak (Energy Standard), Clean Peak Energy Credits (CPECs)	The Clean Peak Energy Standard promotes the use of clean energy to meet demand during peak periods which would otherwise be met with GHG -emitting resources. The Clean Peak Standard provides Clean Peak Energy Credits to compensate clean generation technologies that operate during peak periods, demand-reducing resources that reduce peak load, and storage technologies that shift clean energy into peak periods.
DER	Distributed Energy Resources, technologies connected to the distribution grid which can generate electricity or reduce or shift grid loads. Including energy efficiency, demand response, distributed solar PV, distributed energy storage, and electrification load such as from EV and heat pumps
DG	Distributed Generation, solar PV and energy storage systems that are connected to the distribution system and generate electricity to reduce demand on the system.
DR	Demand Response, programs that compensate customer to reduce their load during hours in which the electric grid faces constraints
EDC	Electric Distribution Company, Massachusetts' major investor-owned utilities
EE	Energy Efficiency, programs that cause long-lived, non-dispatchable load reductions through improvements to building systems, structures, or operations
EJ	Environmental Justice, per the Massachusetts Office of Environmental Justice and Equity, is based on the principle that all people have a right to be protected from environmental hazards and to live in and enjoy a clean and healthful environment. Environmental justice is the equal protection and meaningful involvement of all people with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies and the equitable distribution of environmental benefits
EJC	Environmental Justice Community, a neighborhood or population which has been marginalized on the basis of race, culture, ethnicity, or socioeconomic status and has

	borne disproportional environmental burdens such as inequal access to clean air or water resulting in negative health or economic outcomes.
EJ Populations	Environmental Justice Populations are defined in Section 56 of “An Act Creating A Next-Generation Roadmap for Massachusetts Climate Policy”, as a neighborhood that meets one or more of the following criteria: (i) the annual median household income is not more than 65% of the statewide annual median household income; (ii) minorities comprise 40% or more of the population; (iii) 25% or more of households lack English language proficiency; or (iv) minorities comprise 25% or more of the population and the annual median household income of the municipality in which the neighborhood is located does not exceed 150% of the statewide annual median household income.
ELCC	Effective Load Carrying Capability, the ability of a resource to effectively meet system needs and align with the timing of energy demand. This is often represented as a scalar applied to the rated capacity of the resource
Equity	Equity means engaging all stakeholders with respect and dignity while working toward fair and just outcomes, especially for those burdened with economic challenges, racial inequity, negative environmental impacts, and justice disparities. This includes the three dimensions of equity articulated by the American Council for an Energy-Efficient Economy (ACEEE) in its Leading with Equity Framework; procedural equity, distributional equity, and structural equity. • Procedural equity, which focuses on creating transparent, inclusive, and accessible processes for engagement, such that stakeholders and communities impacted by energy projects and programs are given necessary information and opportunity to participate in processes to inform project siting, development, and implementation. • Distributional equity, which focuses on enabling a more equitable distribution of the benefits and burdens associated with the clean energy transition. • Structural equity, which focuses on developing processes and decisions that are informed by the historical, cultural, and institutional dynamics and structures that have led to inequities
EV	Electric Vehicle
Feeder	Electrical circuits emanating from a substation that supply underground areas at distribution level voltages.
FTM	Front of the Meter, referring to activities, technologies, or systems that are located on the utility side of the electricity meter; see BTM (Behind-the-Meter)
GHG	Greenhouse Gas (emissions)
Grid Services	Value that DERs can provide to the electric grid. This study is primarily focused on localized distribution system value.
Headroom	The margin of available capacity at a specific equipment to accommodate additional load without causing violations of equipment specifications
Interconnection	The connection of DERs to the power grid in a manner that ensures safe operations under all grid conditions
kW/kWh/kW-yr	Kilowatt, kilowatt-hour, and kilowatt-year, measurements of electric energy and capacity
Load	The demand for electricity, electricity consumption, or the amount of electric power delivered to any specified point on a system, accounting for the requirements of the customer’s electrical equipment.

NEM	Net Energy Metering, a form of compensation for a distributed energy resource located on a customer's premise wherein a customer consumes some portion of the generation themselves and is also compensated for energy exported to the grid.
NWA	Non-Wires Alternatives, technologies or operating practices intended to reduce grid congestion and manage peak demand to offset a utility's need to make additional investments in conventional assets like wires, poles, and substations. The technologies can include distributed energy resources, such as microgrids or batteries, and practices and programs focused on load management, demand response or energy efficiency.
O&M	Operations & Maintenance
PCT	Participant Cost Test, one of the standard cost tests used to evaluate the benefits and costs of a measure to participant
Peak Load	Peak load refers to the highest electricity demand experienced by the grid during a specific period
PV	Photovoltaic (solar)
Ratepayer	Electric utility customer. All customers help pay for electric system investments through their utility bills
Reliability	Assurance that electric power is available even under adverse conditions, such as storms or outages of generation or transmission lines.
Resilience	The ability of the grid to withstand and rapidly recover from power outages and continue operating with electricity, heating, cooling, ventilation, and other energy- dependent services.
RIM	Ratepayer Impact Measure, one of the standard cost tests used to evaluate the benefits and costs of a measure to other non-participating utility ratepayers; see SCT
SCT	Societal Cost Test, one of the standard cost tests used to evaluate the benefits and costs of a measure to society at large; see RIM
SMART	Solar Massachusetts Renewable Target, a commonwealth program that provides incentives for solar and paired storage
Substation	A facility used to translate electricity from transmission level voltages to distribution level voltages
TOU	Time of Use, a type of retail rate under which the cost of electricity differs based on the time of day. Also known as Time Varying Rates (TVR).
TRC	Total Resource Cost, one of the standard cost tests used to evaluate the total benefits and costs of a measure within the bounds of the study
VPP	Virtual Power Plant, an aggregation of DERs that can balance electrical demand and supply and provide utility scale and utility-grade services like a traditional power plant.

For additional terminology and acronym definitions, the appendices of the EDCs' Electric Sector Modernization Plans provide detailed glossaries, from which several of the above definitions were borrowed and should be attributed. Links to these ESMPs can be found in the "Additional Resources" section of this primer.

3. Additional Resources and Educational Materials:

Distributed Energy Resources and Grid Services: Summary and background of the Massachusetts Grid Services study.

- https://www.masscec.com/grid-modernization-and-infrastructure-planning/grid-services-study

Distributed Generation and Distributed Energy Resources: Additional background information on DG and DERs.

- Distributed Generation of Electricity and its Environmental Impacts https://www.epa.gov/energy/distributed-generation-electricity-and-its-environmental-impacts
- Distributed Energy Resources for Resilience
- https://www.energy.gov/femp/distributed-energy-resources-resilience#:~:text=Distributed%20energy%20resources%20(DERs)%E2%80%94,Portfolio%20Resilience%20Planning%20and%20Implementation.

Electric Distribution: A summary of Eversource's electric distribution system, including the impacts of DERs such as energy storage and grid modernization.

- https://www.eversource.com/content/residential/about/transmission-distribution/electric-distribution

Electric Sector Modernization Plans: Commonwealth-mandated utility plans for updated distribution and transmission systems to ready the grid for anticipated challenges, including high electrification, increased renewables, climate change, and ratepayer impacts.

- Massachusetts Department of Public Utilities Background: https://www.mass.gov/info-details/electric-sector-modernization-plan-resources?_gl=1%2Aaedzts%2A_ga%2AMTEwNzM0ODMwNS4xNzA1NTA1MjI4%2A_ga_MCLPEGW7WM%2AMTcwODk4MTI5OS4zLjAuMTcwODk4MTI5OS4wLjAuMA..
- Eversource: https://www.eversource.com/content/docs/default-source/default-document-library/eversource-esmp%20.pdf
- National Grid: https://www.nationalgridus.com/media/pdfs/our-company/massachusetts-grid-modernization/future-grid-full-plan.pdf
- Unitil: https://unitil.com/sites/default/files/2024-01/Unitil-ESMP-2025-2050-DPU-FINAL.pdf

Grid Modernization Advisory Council (GMAC): Resources related to the review of the EDCs' ESMPs

- https://www.mass.gov/orgs/grid-modernization-advisory-council-gmac

Existing EDC Programs: A non-exhaustive list of links to existing Commonwealth and utility programs that offer incentives for distributed energy resources.

- Eversource:
  - Residential Customers: https://www.eversource.com/content/residential/save-money-energy
  - Business Customers: https://www.eversource.com/content/business/save-money-energy

- National Grid:
  - Residential Customers: https://www.nationalgridus.com/MA-Home/Energy-Saving-Programs/
  - Business Customers: https://www.nationalgridus.com/MA-Business/Energy-Saving-Programs/
- Unitil:
  - https://unitil.com/ways-to-save

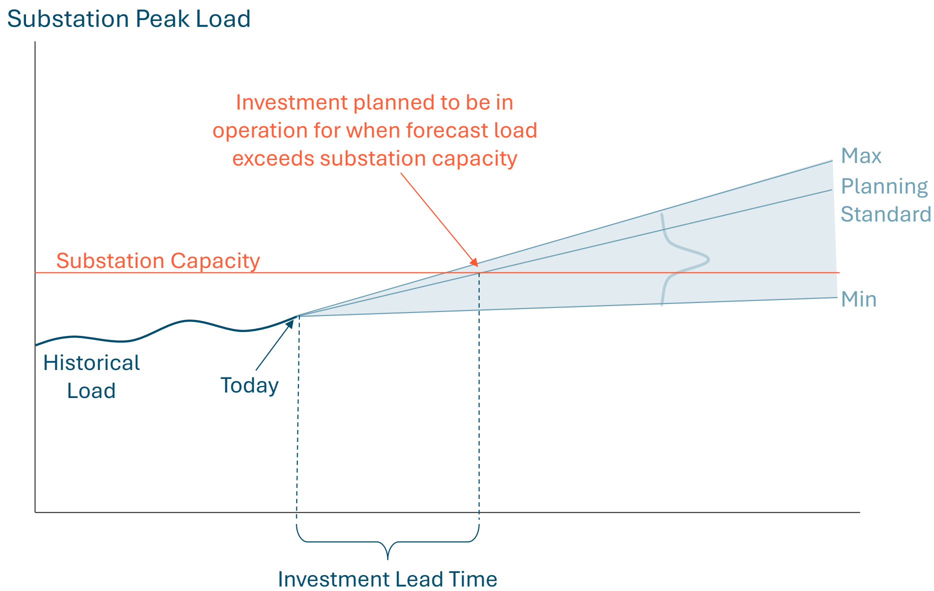
Additional Resources:

- Clean Energy States Alliance (CESA) Resource Library: https://www.cesa.org/resource-library/

Appendix C. Optionality Value

This appendix walks through an illustration of how additional savings can result when improved certainty about grid needs allows for further deferral of infrastructure investments. An illustrative optionality value calculation is included in a separate edition of the valuation model available for download on the Grid Services Study website. As with the other valuation calculations, the purpose of this model is to demonstrate the recommended methodology rather than to arrive at or depict on-the-ground results for any particular location.

Figure 27. Optionality Value – Base Investment Scenario



In a standard grid investment scenario, investments are planned and undertaken well in advance to ensure infrastructure is in place by the time forecasted demand exceeds an asset's existing capacity. Given the uncertainty of future load growth, forecast peak load is best described as a distribution that widens with forecast years that are more distant from present day. This distribution is made explicit in Figure 27. Much distribution planning simplifies this distribution to a singular forecast used for planning, labeled here as the "planning standard". Because planning to avoid outages is inherently conservative, the planning standard forecast draws from a higher-than-50th percentile the distribution.

Investments are timed to align with the point at which the planning standard intersects with the existing substation capacity. Then in the deferral scenario shown by Figure 28, DERs provide additional capacity and delay the infrastructure investment need. The expected deferral time is based on when the planning standard load growth will exceed the combined effective capacity of traditional infrastructure and DERs.

Figure 28. Optionality Value - Deferral Scenario

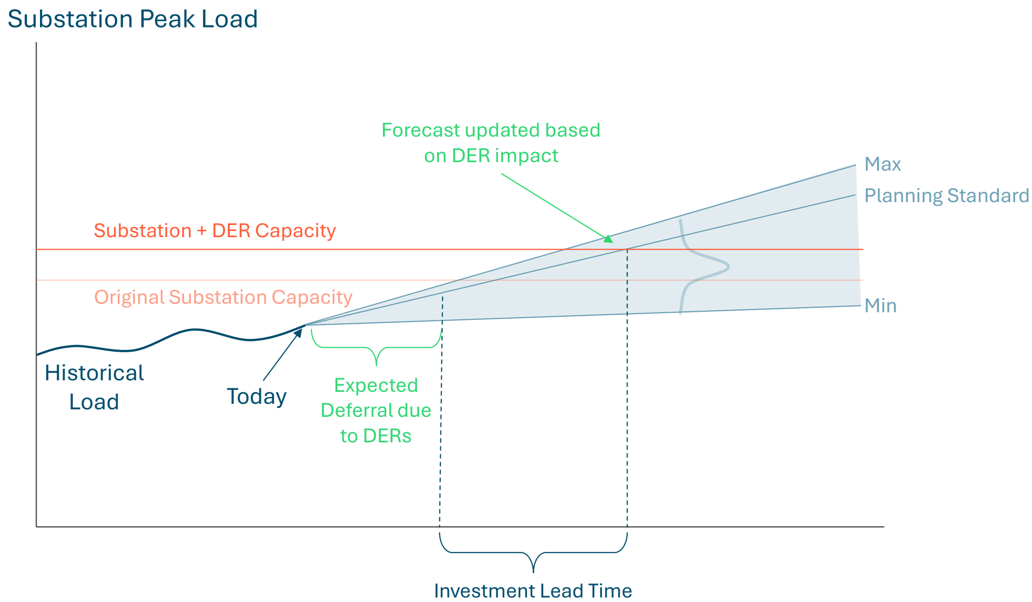
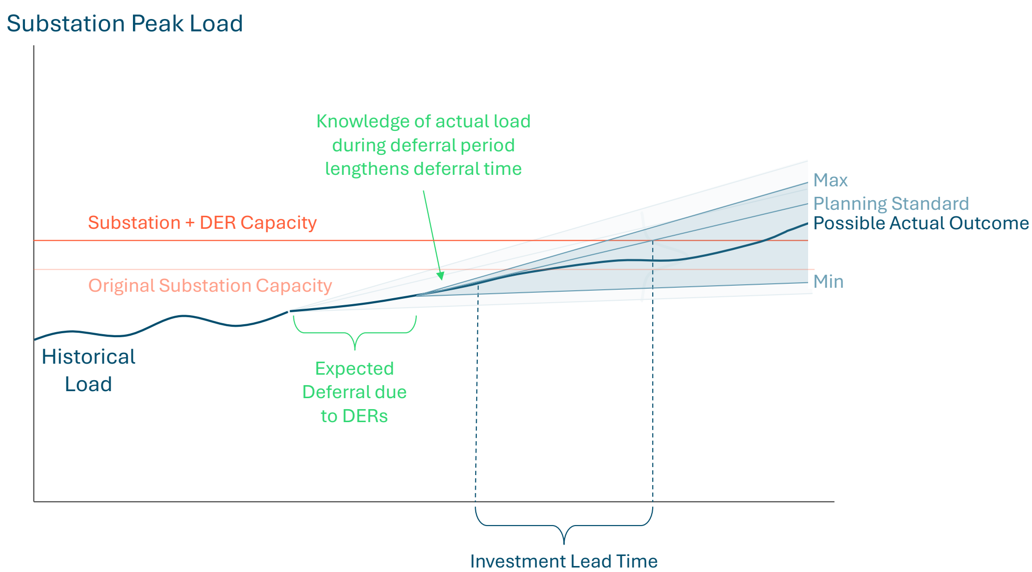


Figure 29. Optionality Value - Post-Deferral



During this period of deferral, new information becomes available such as the actual peak load growth during years that were previously forecast. As shown by Figure 29, load growth below the original planning standard forecast establishes a new lower starting point for an updated planning standard forecast. This pushes the entire planning standard forecast down, resulting in additional deferral time beyond the original calculated period.

The peak load growth occurring during the expected deferral period in Figure 29 is just one of infinitely many possible paths. Other paths could more closely track the planning standard forecast or could be higher than the planning standard forecast. The former case would result in no additional deferral, and the latter case would shorten the originally expected deferral period. However, the use of a conservative planning standard guarantees that, averaged over all possibilities, the additional information lengthens the deferral period.

Methodology

To quantify this optionality value, use stochastic modeling to simulate outcomes across many different probabilistic future scenarios. Given inputs to characterize the peak load forecast distribution and an available DER capacity, we perform thousands of Monte Carlo draws to represent possible peak load futures. For each of these futures, we identify the expected deferral period prior to any deferral and the additional deferral time based on knowledge of actual loads that occur during the initial deferral period. Similar to other deferral calculations, values are rounded down to the nearest integer based on the annual nature of distribution investment planning.

We calculate an average number of deferral years by averaging results across the thousands of draws. Conversation of this average number of years into dollars relies on the same methodology as the deferral investment cost, comparing the NPV of a deferred investment's revenue requirement to the original investment's revenue requirement. This yields an optionality value that we expect to accurately represent the average over many deferral opportunities, though it will often over or understate the value for a specific single opportunity.

Illustrative Results

For example, we start with the same assumptions used to build the example deferral scenario in Section 3.1.1. Figure 30 provides a load forecast, which starts at 90 MW today and evolves based on median escalation of 2.5% per year and some normally distributed variance around this center.[61] The forecast range shown corresponds to the minimum and maximum outcomes from 5,000 Monte Carlo draws. We assume the planning standard forecast aligns with the 70th percentile of this forecast distribution, and that the addition of DER capacity allows for 3 years of investment deferral.

Across 5,000 random simulations of load growth, we gather the distribution of additional deferral years shown in Figure 31. In the figure, the additional years of deferral (beyond the assumed 3 years) appear on the horizontal axis, and the vertical axis provides the frequency of each outcome across the simulations. The vertical line in gold marks the average across all simulations: 0.64 years of additional deferral beyond the 3 years originally assumed. This gives a total deferral time of 3.64 years, which we value at $5.0 million, which is $800 thousand more than the value of deferral without considering the optionality value.

[61] The assumption of a normal distribution is used for the sake of simplicity in this example. Actual forecast distributions may be non-normal in shape.

Figure 30. Modeled Deferral Opportunity with Forecast Uncertainty

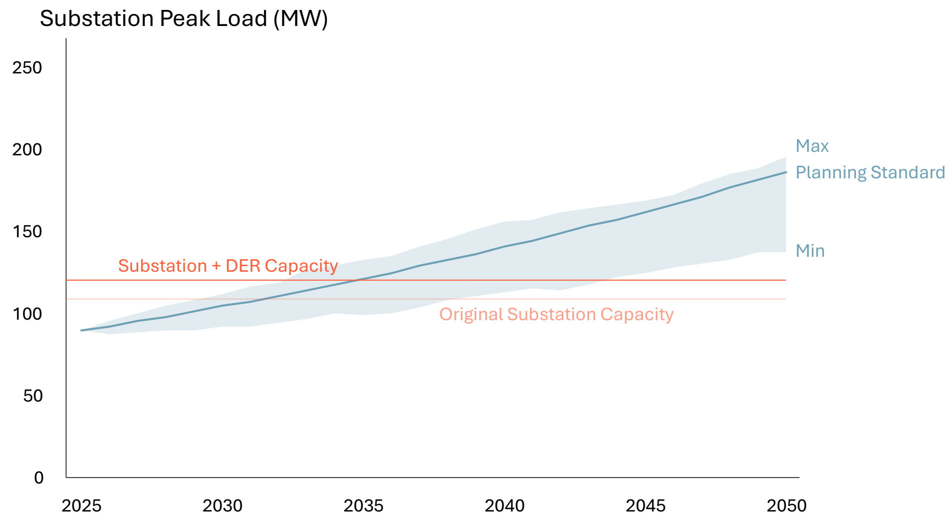
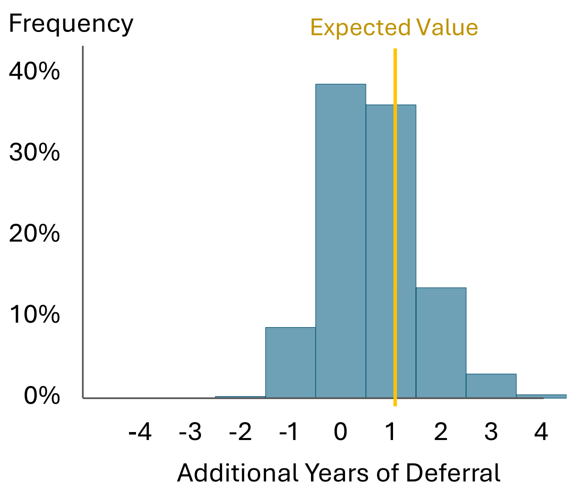


Figure 31. Simulated Frequency of Additional Years of Deferral

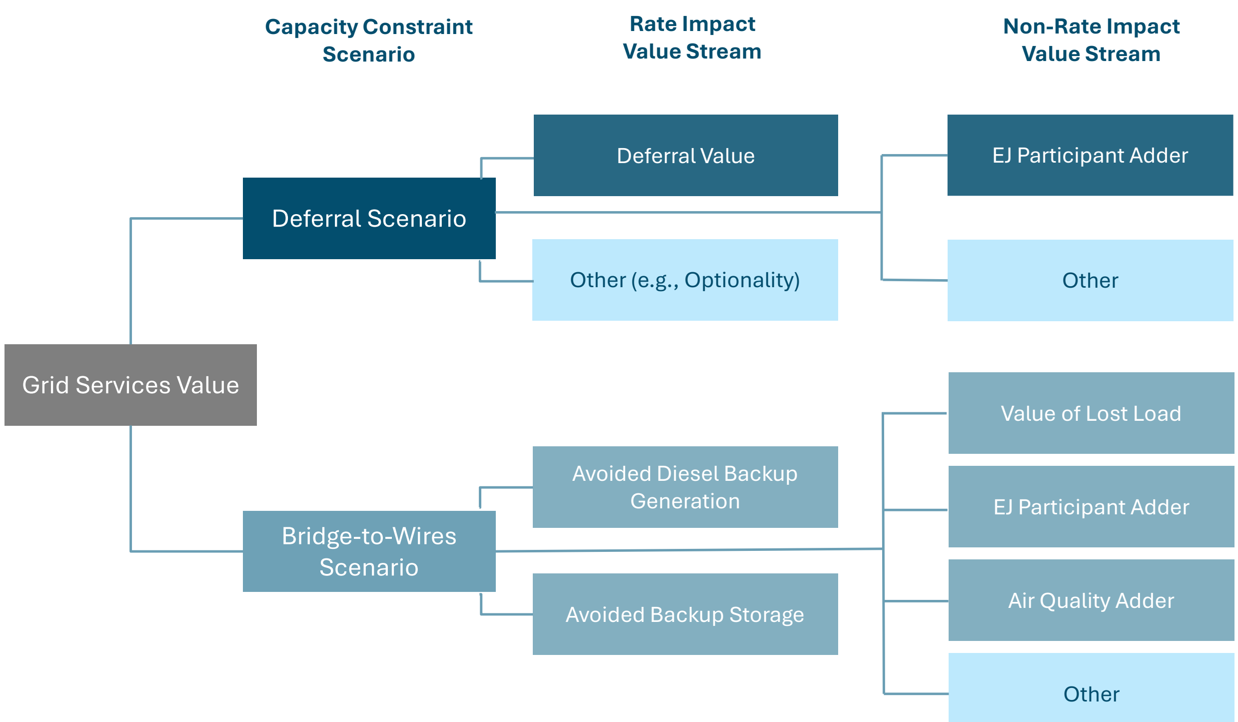


Appendix D. Grid Services Valuation Model Overview

The Grid Services Valuation Model is designed to provide a shared understanding of how the value of DER Grid Services is calculated, which ultimately informs how much DER participants are compensated through Grid Services offerings under two capacity constraint scenarios: (1) a Deferral Scenario and (2) a Bridge-to-Wires Scenario.

Figure 32 illustrates the framework for the model. To determine the DER compensation, we quantify rate impact and non-rate impact value streams for each capacity constraint scenario. For the Deferral scenario, we quantify the deferral value, which impacts the EDC's revenue requirement, and an EJ participant adder to ensure equitable access to DERs. For the Bridge-to-Wires scenario, we quantify the avoided cost of diesel backup generation and the avoided cost of backup storage as rate impacts the EDCs can avoid with flexible DER capacity. As non-rate impacts, we quantify the value of lost load, an EJ participant adder, and an air quality adder for locations that are avoiding diesel backup generation. The methodology for each of these value streams is explained in Section 3.

Figure 32. Grid Services Valuation Model Framework



The model framework also considers other rate impact and non-rate impact value streams, which are not currently included in the Grid Services Valuation model. These could include optionality value, which is described in Section 3 and quantified in the Optionality Model, the value of accelerated interconnections, or avoided construction-related impacts. These other value streams may be assessed in the future when better data and quantification methods are made available.

The Grid Services Valuation model is split into three sections, summarized by the model's table of contents in Table 9. The green sheets are the primary landing pages of the model and describe the model valuation framework as discussed above and include the dashboard, which provides user inputs for the value stream calculations and an example compensation structure.

The blue sheets correspond to the value stream calculations. The Deferral Calculation sheet calculates the value of delaying investments. The Bridge-to-Wires Calculation sheet values DER solutions that bridge the gap between an imminent capacity constraint and the time it takes to complete construction of a traditional infrastructure solution. The EJ Impact Calculation sheet quantifies the value to EJ communities, including an adder to encourage EJ participation and an air quality adder to value the benefits of reducing air pollution in EJ-designated communities.

The brown sheets are reference tabs that provide inputs to the values stream calculations. The ICE Calculator Results sheet includes results from the DOE's Interruptible Cost Estimate calculator that inform the Value of Lost Load calculations in the Bridge-to-Wires Calculation sheet. The Reference Utility Data sheet reports utility data that is applied in the valuation calculations. Finally, the Mappings sheet provides drop-down inputs that are used throughout the model.

Table 9. Grid Services Valuation Model Contents

Sheet	Description
Valuation Framework	Diagram of the valuation framework to illustrate how each value stream flows into the compensation.
Dashboard	Dashboard for User Inputs and Compensation calculations. Valuation user inputs for project-specific data applicable to all valuation calculations. Compensation user inputs to determine customer compensation levels, which are provided as an output in this tab.
Deferral Value Calculation	Calculations for Deferral Value. Deferral Value reflects benefits of delaying investments related to the time value of money.
Bridge-to-Wires Calculation	Calculations for Bridge-to-Wires Value. Bridge-to-Wires solutions are designed to bridge the gap between an imminent capacity constraint and the time it takes to complete construction of a traditional infrastructure solution.
EJ Impacts Calculation	Calculations for Environmental Justice Value. Environmental Justice values include an EJ Participant adder to encourage participation by EJ customers and an Air Quality adder to value the benefits of reducing air pollution from backup diesel generation in EJ-designated communities.
ICE Calculator Results	Results from DOE's Interruptible Cost Estimate calculator applied to Bridge-to-Wires calculation.
Reference Utility Data	Utility-specific data that is applied in the valuation calculations.
Mappings	Dropdown input selections

The Grid Services Valuation model is available on the Massachusetts Clean Energy Center [Grid Services Study website] accompanied by a webinar training to help users explore the model in detail.

Appendix E. Dispatch Price Signals: Examples and Model Methodology

For this study, E3 developed a Combined Incentives Model which compares the price signals available to DERs in the Commonwealth, determines optimal dispatch behavior, and calculates the compensation required to make participation in Grid Services economically attractive in any given hour. This value differs by hour, season, and bulk grid demand. The results from the model illustrate how, in locations where DERs can alleviate distribution grid constraints, relatively modest Grid Services incentives are enough to overcome the opportunity cost of responding to other price signals in many hours of the day.

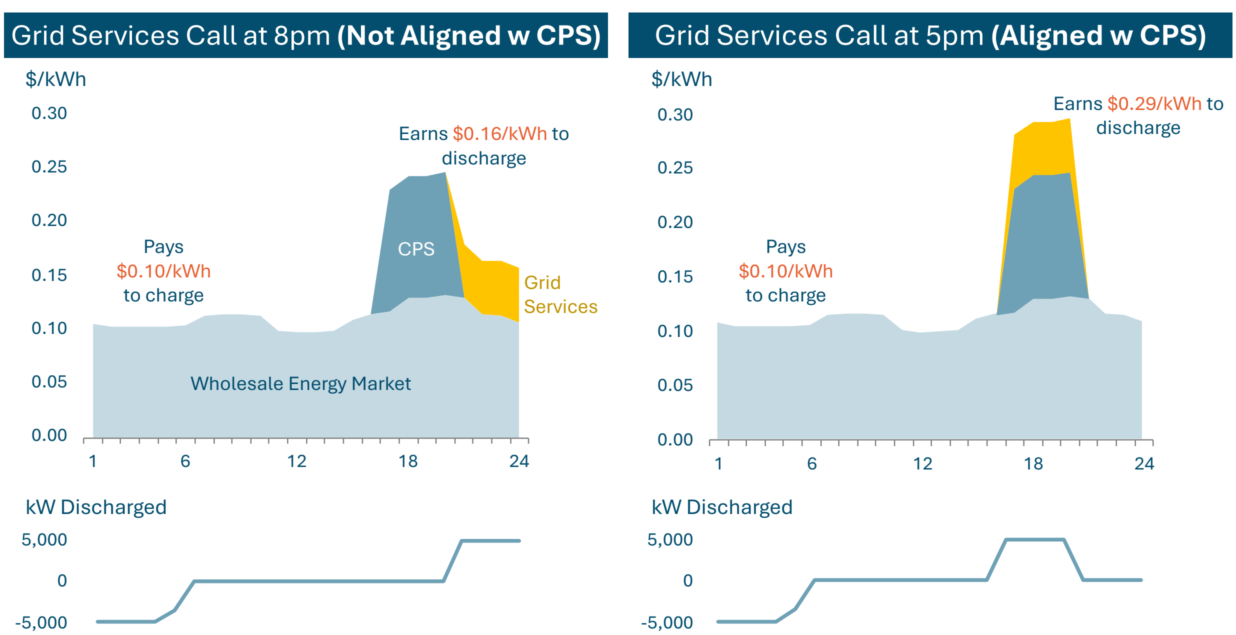
This appendix describes the price signals seen by two different example DERs and calculates the opportunity cost of potential dispatch for Grid Services at different month/hour combinations. A description of the model's methodology follows these examples.

Dispatch Opportunity Cost Examples

Example 1: 5 MW 4-hr Front-of-the-Meter (FTM) Storage Asset

Figure 33 shows two hypothetical examples of Grid Services call timing and the impact of the calls on the hourly price signal seen by a 5 MW 4-hour FTM battery and its state of charge. In the absence of a Grid Services signal, this battery earns revenue from energy arbitrage and Clean Peak credits. The top panels of the figure layer possible Grid Services calls on top of these existing signals, with the height of the combined stack representing the $/kWh earned from discharge or paid to charge in that hour.

Figure 33. FTM Dispatch Demonstration – Aligned Signals vs. Not Aligned Signals



In the left-hand panel, a Grid Services dispatch call occurs directly after the CPS discharge window. Absent any firm commitments, the battery would choose to discharge during the CPS window, where it makes $0.13/kWh on top of revenues from the wholesale energy market of about $0.12/kWh. The dispatch pattern shown in the bottom panels of the figure regards the Grid Services call as mandatory, however. Under this assumption, the battery entirely misses the CPS discharge revenue and the period of relatively higher market prices aligned with it. Instead, the battery earns only about $0.16/kWh, which results in about $1,800 less revenue over the day than the battery would have made absent a mandatory Grid Services Signal.

Alternatively, the right-hand panel of Figure 33 includes a Grid Services signal that aligns perfectly with the CPS discharge window. As a result, the signal to dispatch during the CPS window is only enhanced, and the battery earns about $0.29/kWh for its discharge. In this case, the opportunity cost is zero and so a Grid Services signal may not be needed at all.

Figure 34. Distribution Incentive Value to Break-even During Winter Months

$/kW-yr incentive Value	First Hour of Call: 0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
20	7.1	7.0	7.0	7.2	7.7	8.3	8.5	8.5	8.3	8.2	8.2	8.2	8.2	8.4	12.1	15.9	19.5	19.5	16.1	12.4	8.7	8.4	8.0	7.5
18	5.1	5.0	5.0	5.2	5.7	6.3	6.5	6.5	6.3	6.2	6.2	6.2	6.2	6.4	10.1	13.9	17.5	17.5	14.1	10.4	6.7	6.4	6.0	5.5
16	3.1	3.0	3.0	3.2	3.7	4.3	4.5	4.5	4.3	4.2	4.2	4.2	4.2	4.4	8.1	11.9	15.5	15.5	12.1	8.4	4.7	4.4	4.0	3.5
14	1.1	1.0	1.0	1.2	1.7	2.3	2.5	2.5	2.3	2.2	2.2	2.2	2.2	2.4	6.1	9.9	13.5	13.5	10.1	6.4	2.7	2.4	2.0	1.5
12	-0.9	-1.0	-1.0	-0.8	-0.3	0.3	0.4	0.5	0.3	0.2	0.2	0.2	0.2	0.4	4.1	7.9	11.5	11.5	8.1	4.4	0.7	0.4	0.0	-0.5
10	-2.9	-3.0	-3.0	-2.8	-2.3	-1.7	-1.6	-1.5	-1.7	-1.8	-1.8	-1.9	-1.8	-1.6	2.1	5.9	9.5	9.5	6.1	2.4	-1.3	-1.6	-2.0	-2.5
8	-4.9	-5.0	-5.0	-4.8	-4.3	-3.7	-3.6	-3.5	[illegible]	[illegible]	[illegible]	[illegible]	-3.8	-3.6	0.1	3.9	7.5	7.5	4.1	0.4	-3.3	-3.6	-4.0	-4.5
6	-6.9	-7.0	-7.0	-6.8	-6.3	-5.7	-5.6	-5.5	-5.7	-5.8	-5.8	-5.9	-5.8	-5.6	-1.9	1.9	5.5	5.5	2.1	-1.6	-5.3	-5.6	-6.0	-6.5
4	-8.9	-9.0	-9.0	-8.8	-8.3	-7.7	-7.6	-7.5	-7.7	-7.8	-7.8	-7.9	-7.8	-7.6	-3.9	0.2	3.5	3.5	0.1	-3.6	-7.3	-7.6	-8.0	-8.5
2	-10.9	-11.0	-11.0	-10.8	-10.3	-9.7	-9.6	-9.5	-9.7	-9.8	-9.8	-9.9	-9.8	-9.6	-5.9	-2.2	1.5	1.5	-1.9	-5.6	-9.3	-9.6	-10.0	-10.5
0	-12.9	-13.0	-13.0	-12.8	-12.3	-11.7	-11.6	-11.5	-11.7	-11.8	-11.8	-11.9	-11.8	-11.6	-7.9	-4.2	-0.5	-0.5	-3.9	-7.6	-11.3	-11.6	-12.0	-12.5
0	-14.9	-15.0	-15.0	-14.8	-14.3	-13.7	-13.6	-13.5	-13.7	-13.8	-13.8	-13.9	-13.8	-13.6	-9.9	-6.2	-2.5	-2.5	-5.9	-9.6	-13.3	-13.6	-14.0	-14.5

Zero Net Benefit to DER Owner

Figure 34 depicts revenue impact results for different Grid Services incentive prices and hours of the day. The vertical axis shows the incentive level of the distribution call, while the horizontal axis indicates the hour of the day when the call begins. The values in the matrix are the incremental revenues that an asset enrolled in a Grid Services offering would earn if it dispatches to prioritize Grid Services relative to how it would dispatch in the absence of any Grid Services call.

In this hypothetical scenario, we simulate 30 Grid Services calls, which each last 3 hours, throughout the winter. Red-shaded regions denote incentive levels at which prioritizing Grid Services response would result in revenue loss, while blue-shaded regions indicate increases in revenue due to Grid Services response. The black line shows the incentive level that corresponds to zero net benefit for the DER owner; values just above the line indicate the minimum Grid Services incentive needed to incentivize FTM participation in each hour of the day.

As we saw in the dispatch example of Figure 33, there is no opportunity cost associated with aligned with the CPS discharge window. For storage to dispatch in off-peak hours, it must earn more from the Grid Services incentive than the opportunity cost of all the other revenue streams available to it. In this particular example, that break-even value floats around $13/kW-yr, but this value will change depending on the CPS multipliers a DER receives and the specific wholesale energy market prices of a given day.

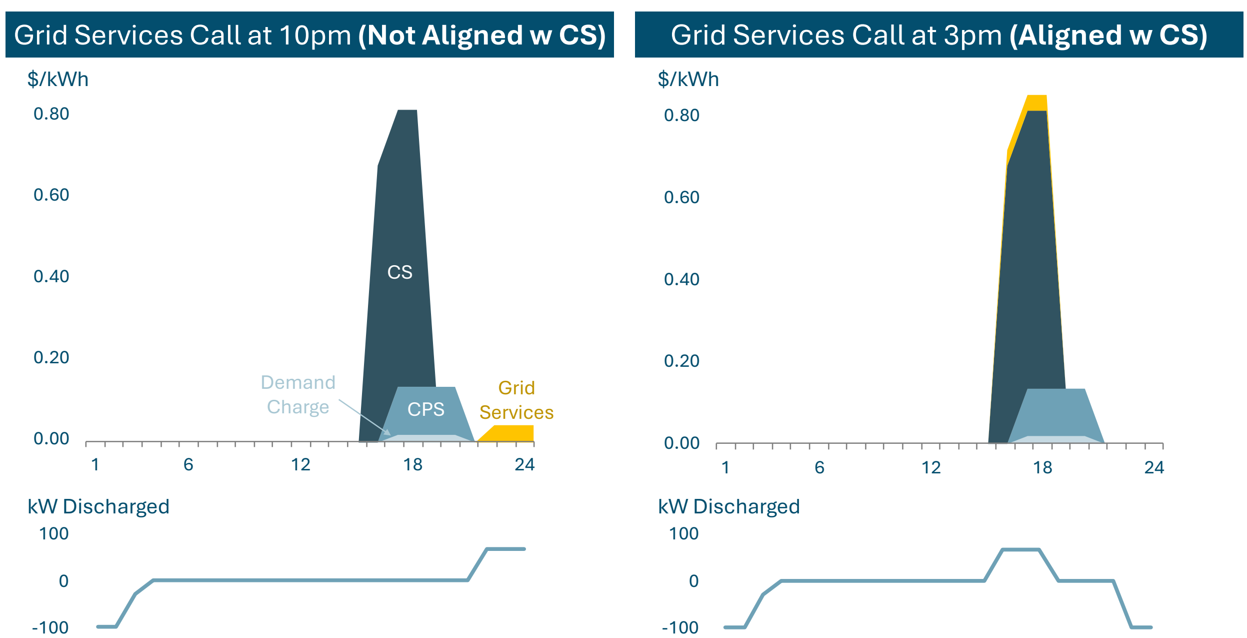
Example 2: 100 kW 1-hr Behind-the-Meter (BTM) Storage Asset (2025)

Figure 35 shows two hypothetical examples of Grid Services call timing and the impact of the calls on the hourly price signal seen by a 100 kW 1-hour BTM battery. In the absence of a Grid Services signal, this battery earns revenue from a ConnectedSolutions call, Clean Peak credits, and by reducing consumption during the demand charge window of the customer's retail rate. The top panels of the figure layer possible Grid Services calls on top of these existing signals, with the height of the combined stack representing the $/kWh earned from discharge or paid to charge in that hour.

In the example shown in Figure 35, the DER dispatches to meet the Grid Services call marked in yellow (regarding the calls as mandatory). On the left, the DER dispatches in hours 21-23 and earns ~$4/kWh, fully missing the ConnectedSolutions call and its revenue. On the right, when the calls are coincident, the DER dispatches in hours 15-17 and earns ~$80/kWh.

The large differential in the stack heights shows that the DER would earn more by discharging to meet the ConnectedSolutions call, rather than the Grid Services call. Grid services compensation values can be minimal in hours that coincide with ConnectedSolutions, Clean Peak, and demand charges. To influence DER behavior when the hours do not align, the compensation must be higher than other incentive programs.

Figure 35. BTM Dispatch Demonstration Aligned Signals vs. Not Aligned Signals



The chart in Figure 36 shows the difference in total system revenue if the system is forced to dispatch in response to the Grid Services need, at various distribution incentive prices and hours of the day. In this scenario, there are 30 distribution calls, each lasting 3 hours, throughout the summer. Some, but not all of these calls may occur on days with ConnectedSolutions calls, which is why the average price to overcome is lower than the ConnectedSolutions price shown in the previous figure.

Figure 36. BTM Distribution Incentive Value to Break-even During Summer Months

$/kW-yr incentive Value	First Hour of Call: 0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
55	15.0	15.0	13.3	13.3	13.3	15.0	15.0	15.0	15.0	15.0	13.3	15.0	15.0	15.0	13.4	24.7	37.2	55.0	34.7	15.6	0.0	0.0	15.2	17.7
50	10.0	10.0	8.3	8.3	8.3	10.0	10.0	10.0	10.0	10.0	8.3	10.0	10.0	10.0	8.4	19.7	32.2	50.0	29.7	10.6	-5.0	-5.0	10.2	12.7
45	5.0	5.0	3.3	3.3	3.3	5.0	5.0	5.0	5.0	5.0	3.3	5.0	5.0	5.0	3.4	14.7	27.2	45.0	24.7	5.6	-10.0	-10.0	5.2	7.7
40	0.0	0.0	-1.7	-1.7	-1.7	0.0	0.0	0.0	0.0	0.0	-1.7	0.0	0.0	0.0	-1.6	9.7	22.2	40.0	19.7	0.6	-15.0	-15.0	0.2	2.7
35	-5.0	-5.0	-6.7	-6.7	-6.7	-5.0	-5.0	-5.0	-5.0	-5.0	-6.7	-5.0	-5.0	-5.0	-6.6	4.7	17.2	35.0	14.7	-4.4	-20.0	-20.0	-4.8	-2.3
30	-10.0	-10.0	-11.7	-11.7	-11.7	-10.0	-10.0	-10.0	-10.0	-10.0	-11.7	-10.0	-10.0	-10.0	-11.6	-0.3	12.2	30.0	9.7	-9.4	-25.0	-25.0	-9.8	-7.3
25	-15.0	-15.0	-16.7	-16.7	-16.7	-15.0	-15.0	-15.0	-15.0	-15.0	-16.7	-15.0	-15.0	-15.0	-16.6	-5.3	7.2	25.0	4.7	-14.4	-30.0	-30.0	-14.8	-12.3
20	-20.0	-20.0	-21.7	-21.7	-21.7	[illegible]	-20.0	-20.0	-20.0	-20.0	-21.7	-20.0	-20.0	-20.0	-21.6	-10.3	2.2	20.0	-0.3	-19.4	-35.0	-35.0	-19.8	-17.3
15	-25.0	-25.0	-26.7	-26.7	-26.7	-25.0	-25.0	-25.0	-25.0	-25.0	-26.7	-25.0	-25.0	-25.0	-26.6	-15.3	-2.8	15.0	-5.3	-24.4	-40.0	-40.0	-24.8	-22.3
10	-30.0	-30.0	-31.7	-31.7	-31.7	-30.0	-30.0	-30.0	-30.0	-30.0	-31.7	-30.0	-30.0	-30.0	-31.6	-20.3	-7.8	10.0	-10.3	-29.4	-45.0	-45.0	-29.8	-27.3
5	-35.0	-35.0	-36.7	-36.7	-36.7	-35.0	-35.0	-35.0	-35.0	-35.0	-36.7	-35.0	-35.0	-35.0	-36.6	-25.3	-12.8	5.0	-15.3	-34.4	-50.0	-50.0	-34.8	-32.3
0	-40.0	-40.0	-41.7	-41.7	-41.7	-40.0	-40.0	-40.0	-40.0	-40.0	-41.7	-40.0	-40.0	-40.0	-41.6	-30.3	-17.8	0.0	-20.3	-39.4	-55.0	-55.0	-39.8	-37.3

Zero Net Benefit to DER Owner

The results show the strength of the signal for storage systems to dispatch in peak evening hours to earn ConnectedSolutions and CPS revenues. For storage to dispatch during different hours, the system must earn more from the distribution incentive than the opportunity cost of other revenue streams. The black line at zero net benefit to the DER owner shows the minimum Grid Services incentive needed to incentivize BTM participation in each hour of the day (~$38/kW-yr).

Combined Incentives Model Methodology

This section outlines the methodology used in the Combined Incentives Model, a spreadsheet-based tool developed to estimate battery storage operational behavior and revenues under a range of FTM and BTM configurations. The model calculates revenues from different incentive programs and market opportunities to determine reasonable incentive levels for Grid Services offerings. Key technical and economic assumptions can be customized to reflect project-specific conditions and explore how different incentive structures interact.

Battery Storage Revenues

Front-of-the-Meter (FTM) Projects

The model calculates the daily revenue by subtracting the highest priced hours when the battery discharges from the lowest priced hours when the battery charges. The duration, capacity, and round-trip efficiency of the battery are user inputs. The battery only cycles on days when the net revenue from discharge is positive.

Behind-the-Meter (BTM) Projects

BTM batteries cycle to reduce retail bills. Retail bill inputs are based on current Eversource and National Grid Commercial and Residential rate schedules. The battery charges and discharges at the retail rate cost of energy. For rates with demand charges, the battery discharges to lower peak demand and coincident peak demand. Similarly to the FTM configuration, the duration, capacity and round-trip efficiency are user inputs and the battery only cycles on days when net revenue is positive.

Incentive Revenues

Users can select to include incentive programs, including the Clean Peak Energy Standard, ConnectedSolutions, and SMART. When each program is selected, the incentive values are added to the price signal that a battery uses to make charging and discharging decisions.

Clean Peak Energy Standard

In each year, the Alternative Compliance Payment (ACP) established by DOER informs the price per Clean Peak credit. This is the value a DER can earn for one MWh of discharge during Clean Peak hours. In eligible hours, the $/MWh Clean Peak price is added to the $/MWh energy price to provide greater incentive to discharge. The battery operates to maximize net revenue with higher revenues earned for discharging during peak hours. The MWh of optimal storage dispatch in those hours are multiplied by the relevant credit multipliers. Summer and winter dispatch receive a 4x credit multiplier, the peak demand hour of each month receives a 25x credit multiplier, BTM storage assets receive 1.5x, and resources also enrolled in SMART receive 0.3x. The number of credits earned are multiplied by the price per credit to determine CPEC revenue.

ConnectedSolutions

ConnectedSolutions calls occur 30-60 times over the summer and last for 2-3 hours. The specific number of calls is a user input. The model selects the date and time of these calls based on the highest summer AESC avoided cost hours. Calls can occur only once a day. When a call occurs, the incentive value is added to the price signal, in a similar manner to the Clean Peak incentive. If the battery dispatches during these high-priced hours, the MWh battery performance earns ConnectedSolutions payments.

SMART

The SMART incentive is a $/kWh adder. This incentive value is added to each MWh of solar produced. The total SMART program capacity is allocated to different utilities and categories based on system characteristics. Solar paired with storage is the category represented in this model. This is further divided into capacity blocks with a pre-determined capacity. SMART is a declining-block incentive program, which means that after a block is filled, the next block will have a lower incentive rate than the previous block. The value of the adder in the model is calculated based on the current tranche and the capacity of the paired storage. These are both user inputs.

Distribution Incentive Revenues

To add a distribution incentive, users select the number of calls, length of calls, call window during the day, call season, incentive value ($/kW-year) and whether or not calls are mandatory. Calls can be based on a user-input load profile or the AESC avoided costs. Call logic works in a similar way to ConnectedSolutions. The top hours (whether highest demand or highest prices) have calls. When calls occur, their incentive value is added to the price signal. Annual participation in calls determines the compensation an asset receives. When distribution calls are set to “Mandatory” the dispatch algorithm is forced to dispatch during these calls. As such, the battery always earns the full $/kW-year revenue. The battery often earns less revenue from other value streams because it cannot economically dispatch to meet arbitrage, Clean Peak, ConnectedSolutions, or demand charge price signals.

Heat maps output from the model, such as the one shown in Figure 34, indicate the impact of a mandatory distribution call on net revenues for a project. These map show that when an asset is forced to dispatch uneconomically, but earns low revenues from the Grid Services offering, it loses money over the course of the year. At this price level, a DER would not enroll in the offering. The break-even price for each hour (White in the graph, for 0) shows the minimum incentive that a DER would need to economically participate.