The Value of Distributed Energy Resources for Distribution System Grid Services

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1 Executive Summary & Report Structure

1.1 Executive Summary

1.1.1 Context and Scope

As the energy market shifts toward mass electrification of heat and transportation, sectoral decarbonization strategies for buildings and housing, and an increasing appetite for localized energy solutions to enhance reliability and resiliency, the electric distribution sector has become a key enabler for expanding and decarbonizing energy use.

Distributed Energy Resources[1] (DER) are expected to play a significant role in enabling a lower-carbon distribution grid and total energy system. But despite the development of incentives such as state-mandated targets for DER adoption, large-scale DER projects are proving difficult to site and interconnect. This has driven most DER development to locate in the easiest siting locations to quickly tap existing wholesale market opportunities and state sponsored tariff-based retail programs, but unfortunately has not driven uptake in locations that could provide the greatest long-term total system benefit. In the absence of defining the value that DER can provide for distribution grid services, a key missing part of the value equation, large-scale DER may be sited in locations and operated in ways that will increase future costs for customers.

Greater total system value will require a much higher level of on-going coordination between wholesale market operators and electric distribution companies (EDCs). It will also require more sophisticated contracting, communication, and dispatch capabilities between EDCs and DER developers including modifying existing protocols that focus primarily on assessing DER feasibility at the time of interconnection, with limited interaction for on-going operations.

For these reasons, and to simplify the initial assessment of the market opportunity for DER to provide value for distribution grid services, the scope of this project focused on the value of DER assets on the distribution grid that are: 1) 500 kW and above, 2) front of the meter, and 3) dispatchable.

Thoughtful market designs are the key foundation to maximizing the value that DER can provide to the broader energy system, with the potential to address an expanding set of use cases as energy markets evolve. This report lays out a framework for describing DER value and for defining market and policy frameworks, commercial constructs, technical standards, and operational enablers to underpin investment and operational confidence. The report represents the culmination of work carried out between Baringa, the Massachusetts Clean Energy Center (MassCEC), representatives from two of the Massachusetts EDCs [National Grid and Eversource], and representatives from the Massachusetts Department of Energy Resources (DOER). The report also incorporates feedback from external stakeholders (e.g., energy storage developers, aggregators, DER optimization service providers) to incorporate points of view from those currently engaged in the development of resources at the distribution level of the network. The document culminates in a recommendation from Baringa on opportunities that MassCEC, working in collaboration with EDCs, DOER, and other stakeholders, could pursue to test the findings from this report in real-life scenarios.

[1] Distributed energy resources are small, modular, energy generation and storage technologies that provide electric capacity or energy where you need it. – NREL - https://www.nrel.gov/docs/fy02osti/31570.pdf

1.1.2 Key Findings

Dispatchable DER can provide a wide range of benefits to energy systems if properly sited, contracted and operated. As electric demand increases, and uncertainty about the location, pace, and scale of electrification persists, dispatchable DER can play an important role in providing grid operators options for addressing evolving network needs. Dispatchable DER may be valuable to 1) provide benefits from investment deferral (which may be short-term as at some point network needs may require a network upgrade anyway), and 2) provide benefits from better capacity utilization across energy resources and networks which may be more enduring.

A key challenge will be in finding the balance between the EDCs' need to provide a reliable network, revenue opportunities in the form of new products that are attractive to developers, and benefits to rate-paying customers. For both EDCs and external stakeholders there is a preference for long-term value of DER contracts, which provide reliability of service and revenue assurance. The primary mission of the distribution system remains safe and reliable grid service at an optimal price.

1. ***Increasing electrical network demands are driving new opportunities for dispatchable DER to provide valuable distribution system grid services.***

EDCs have critical decisions to make about the timing and method of distribution network capacity upgrades which will require significant capital investment to enable electric demand growth to meet 2050 net zero goals. Key questions persist on how EDCs should plan and execute these investments to ensure that any decisions made provide capacity to support predicted growth at an affordable cost. There are two drivers for EDCs to expand network capacity – 1) providing network capacity to serve load directly, and 2) providing network capacity for distributed generation to inject power back onto the grid, also known as hosting capacity. In evaluating the potential benefits of DER in providing distribution grid services, we found that the primary focus for deriving network benefits from DER should be to ensure that these two views of network capacity can be accommodated on the distribution network.

Distribution network capacity is limited by the physics of how electricity flows on a network. Broadly, there are two types of constraints that affect distribution network performance: 1) thermal constraints, and 2) voltage constraints. Thermal constraints are exceeded when too much electrical current flows through power systems which causes equipment temperature to rise. As electrical flow exceeds thermal constraints on a circuit, overhead lines sag and contact trees, and underground conductors and transformers overheat and fail. Voltage constraints are exceeded when the voltage for a particular piece of equipment or the voltage delivered to a customer is too high or too low (also known as a "brownout") which can damage utility and customer equipment and cause cascading issues. Voltage effects on a network are highly localized. In some cases, loads on the end of the line may experience a dramatically different voltage than those closer to a distribution substation.

2. ***Resolving <u>thermal constraints</u> will drive most distribution benefits from dispatchable DER at this stage in Massachusetts.***

Increasing thermal constraints requires significant capital expenditure to upgrade transformers and lines to carry greater electrical loads. Given these assets last for many decades, the decision on whether, when, and how much to upgrade a piece of equipment or a section of network is a critical, difficult, and nuanced decision. Thermal upgrades are a "lumpy" investment where once the decision has been made, upgrades are typically oversized because of the long duration and uncertain conditions under which the upgrade needs to perform. In contrast, many voltage constraints can be addressed via smaller incremental investments over time including capacitor banks, synchronous condensers, static var compensators, and smart inverter controls which can be deployed in more right-sized, purpose-fit, locationally optimized investments. In fact, adding voltage control equipment at larger commercial and industrial customer sites as part of a new connection process is common. Voltage upgrades therefore often represent an easier "incremental" investment.

3. ***Dispatchable DER provide an option for EDCs to resolve thermal constraints with smaller, more incremental investments.***

One of the largest benefits dispatchable DER can provide to network investment and operations decisions is to break thermal constraints into smaller, incremental pieces. By utilizing dispatchable DER to address constraints, EDCs can potentially delay, or reduce the size and uncertainty of some capital investments. Further, EDCs can then steer network equipment investment into areas less suitable for DER development or where rapidly expanding electric network demands far outstrip the capacity of DER to provide thermal constraint relief. Depending on the size and location of a forecasted thermal constraint, this could create the opportunity for EDCs to utilize smaller DER assets (including those much smaller than 500 kW), and design grid services with more flexible and diverse alternatives. 500 kW is a relatively large distribution load, equivalent to roughly 20 new single family housing units or 50 level-2 electric vehicle home charging connections. For many portions of EDC distribution networks, a grouping of multiple smaller DER that provide more resource diversity, may provide more attractive incremental and reliable thermal constraint relief than a single larger dispatchable DER.

4. ***In a radial distribution network, dispatchable DER must be sited downstream of constrained equipment to resolve thermal constraints.***

For dispatchable DER to be effective in managing thermal constraints, they need to be connected downstream from the constraint. For example, in a suburban or rural section of the grid, which are typically designed in a radial "hub and spoke" fashion, the DER needs to be connected closer to the end-use electrical demand (further out on the spoke) to allow reduced power flow on the lines and transformers upstream that are violating thermal constraints. It provides no value to reduce loading on the network upstream on the "wrong side" of the constraint. As a result, properly siting DER – down to the individual feeder, phase, and network segment – is critical to enable DER to provide distribution network value. Some dense urban distribution networks (e.g., Boston) are designed in a meshed configuration with multiple alternative paths to serve loads. Meshed networks require additional network analysis to determine whether and where a dispatchable DER can be sited to resolve thermal constraints.

5. ***A broad range of DER types and sizes have the required operational and control sophistication to provide distribution grid services.***

If EDCs are to modify their grid investment philosophy to rely on DER to provide relief for thermal constraints, they need to be certain that DER will perform when called upon. There is no price benefit or efficiency advantage at which an EDC would risk voluntary loss of load attributable to a DER not performing as contracted to supply distribution grid services. As a result, the sophistication and reliability of control technologies are paramount to building a case for DER if they are to provide critical distribution grid services. At the outset of the engagement, MassCEC designed the scope and sizing of DER resources for review (500 kW and above) with the thought that larger DER would have more advanced capabilities for control and therefore would be more reliable. Through our engagement with DER developers, operators, and aggregators, we confirmed that the desired control and dispatch capabilities are widely available across asset sizes, including those much smaller than 500 kW. From an operational standpoint, the hypothesis was that it would only be feasible for larger assets to be able to take dispatch instructions, operate in real time, and provide enough data to ensure reliability, but research and stakeholder engagement has shown that this is not the case.

The key challenge to delivering DER benefits to the distribution grid appears to be an operational one - though there may be more smaller assets that are available to provide value, EDCs may not have the capability internally to manage the end-to-end processes and operation of a larger pool of assets. There is a natural tension between the need to access the value that a pool of smaller DER might provide and being able to manage the operation of this type of system. It will be a key next step for EDCs to explore the balance between their capability and willingness to manage a pool of smaller assets, testing various levels of control assurance to de-risk the need to be dependent on a single larger asset to provide flexibility.

EDCs will need to further explore and understand the operational characteristics of DER – whether they are dispatchable or not, whether their flexibility is pre-scheduled or dynamic, the degree of control (e.g., central control vs. localized). Each of these operational characteristics will have technical and financial implications. If the desire is to build gradually and learn incrementally, the approach could be to target the larger resources with simple control schemes, understanding the benefit and trade-offs and then later apply these learnings to a broader set of resources to evaluate operational and control alternatives.

6. ***Many distribution constraints are highly localized and will have a limited number of dispatchable DER that can effectively resolve them, especially when compared with transmission or wholesale market supply issues. In the event of conflicting needs between distribution, transmission, and supply, <u>distribution constraints should take priority</u>.***

Any distribution services market for DER must acknowledge that there are competing market and grid needs and value that a DER could support. Constraints at the distribution level are, by definition, localized, and thus there is a smaller pool of resources that can respond. Operationally, there will need to be considerations for how assets would be dispatched to address these constraints and should consider the use of DERs under local grid loading situations or alternate network configurations. These types of hierarchies and dispatch principles would need to be considered carefully to allow for coordinated participation in existing markets.

7. ***Network needs should drive the definition of a consistent set of product definitions for distribution grid services from dispatchable DER. The simplest, most consistent needs should drive early product development.***

Distribution service definitions should address a specific network need. For example, products like load shifting, peak load reduction, distribution congestion management, and post-event restoration support all have different requirements for resource response which will vary by location and time. However, the underlying distribution services products should be designed in ways to be both deliverable and scalable.

Given the complexity of need-driven product design and the design of any commercial arrangement that sits alongside it, the recommendation would be to start with the network need that is the most valuable, easiest to spot, and most consistent. In this case, designing products to address thermal constraints should be the starting point to translate this network need to a product designed with a combination of mutually attractive elements around connection processes, cost of connection, and value. As these products are developed over time, standardized language, commercial structures, and evaluation processes are key to draw as wide a range of flexibility service providers to bridge the gap for participation of existing assets and optimize the deployment of new assets.

8. ***Dispatchable DER will be economically attractive in more situations to provide distribution grid services when appropriate co-participation rules are established that allow DER owners to stack revenues across markets but without jeopardizing distribution service reliability.***

Dispatchable DER participate in multiple markets today including those for wholesale energy, capacity, and transmission grid services. In many cases, and for most hours in a year, the dispatch of DER for these markets will not conflict with the time periods when distribution grid services are required. With appropriate co-participation rules developed, and rigorous operating and control regimes established, the cost to EDCs for dispatchable DERs to ***also*** provide distribution grid services can be minimized thereby unlocking more cases where they can provide value to EDCs and reduce costs to rate-paying customers.

Given that network needs change over time at all levels of the network, so will the definitions of products and services designed to meet these needs. It would be inefficient procurement to overprescribe how assets would need to behave to address a need that exists now but could evolve. Design should allow for co-participation in existing markets. Our recommendation is that there is a need to define a hierarchy of grid needs across the system and understand the uniqueness of a particular resource to resolve a need – this can inform a view of the best use of that resource for the product. There is a need to understand the dispatch principles and hierarchy of needs and to capture this understanding as a part of contractual arrangements for any product.

9. ***Flexible interconnections provide a mechanism to reduce the cost of DER interconnection that can be used in conjunction with revenue stacking to lower the cost of DERs, increasing their competitiveness for providing distribution grid services.***

DER developers incur costs at different points in time including upfront equipment costs, interconnection costs, and on-going operational costs. Interconnection costs are frequently the largest unknown and uncontrollable variable in DER development. One approach to help manage this uncertainty is the development of flexible interconnections which allow DER to connect at a lower cost but while committing to a defined set of operational parameters. Essentially, these such flexible interconnection arrangements are a form of contracted grid services.

1.1.3 Recommendation

Understanding network needs, dispatch hierarchies and product design will create an opportunity to find the balance between reliability and revenue. From experience and research on the way these types of arrangements have evolved in other geographies, if these value of DER programs are to be scalable, they would typically require additional regulatory mechanisms. Starting in a safer environment such as a pilot or trial phase will provide the opportunity to test some of these boundaries and develop learnings to inform where the balance sits.

We propose two approaches that could be utilized in a trial setting:

- Trial A, our recommended priority trial, would enable DER to provide peak load management to mitigate a thermal network constraint, and participating DER would need to be controlled by the EDC, for example through use of Active Network Management (ANM). The purpose of this trial would be to test the various ways in which service provision could be contracted given the EDCs have full operational control (whether that is through an upfront flexible connection agreement or a more dynamic commercial arrangement that evolves with the network need).
- Trial B, an alternative, second priority trial would test a scenario where DER would be contracted to provide flexibility services to the EDC, but there would be no direct control of the DER by the EDC. The purpose of this trial would be to examine which network needs could be addressed through such an arrangement, and what conditions would need to be in place to allow it. For Trial B, EDCs would select "low risk and consequence" grid locations where failure to provide grid services would not put grid reliability at risk. Once dispatch performance could be verified, the trial could be progressively expanded to more real-world constraint situations.

Each of these approaches will allow deeper understanding of the value of flexibility for solving thermal constraints and would involve both the EDCs and developer community to make these trials a reality. To further develop these trials, it is critical that EDCs identify a set of sites with characteristics where flexibility use cases could be tested.

1.2 Report Structure

The key components of the analysis on this project are outlined in Table 1 below, dividing up the insight into three frameworks, each of which needs to be in place if the EDCs are to successfully secure distribution grid benefits from the interconnection and operation of DERs.

Having a coherent set of frameworks ensures that the EDCs can correctly recognize instances in which DER can create value (or drive costs), enables them to develop compensation structures that are appealing to DER operators and elicit the right behaviors, and ensures that the implementation of these compensation structures can be done with low transaction costs, ensuring efficient outcomes for DERs and the EDCs themselves.

Table 1 – Core Frameworks

Framework Element	Description
Benefit and Cost Framework (BCF)	The **Benefit and Cost Framework (BCF)** identifies and – to the extent possible – quantifies the benefits and costs (hereafter called "impacts") that can accrue to EDCs (and their customers) because of DER interconnecting with and operating on the distribution network. Having a robust BCF for recognizing these impacts and understanding how they are affected by DER location and behavior is crucial. It is the basis against which EDCs can develop market (or other) arrangements to affect how DER interconnect and operate for the benefit of rate-paying customers.
Operational Framework (OF)	The **Operational Framework (OF)** provides descriptions and recommendations on the mechanisms for measuring asset performance, the operational windows, and required equipment for communications and metering. The focus is geared towards an understanding of how and where commercial aggregation of DER assets to address grid constraints can be viable and the operational elements surrounding that feature. In addition, we conduct an assessment of the upfront and ongoing maintenance costs for EDC control of assets, from metering and control, through to software for market management, advanced grid management, and organizational costs.
Compensation Structure Framework (CSF)	The **Compensation Structure Framework (CSF)** details the current issues facing the industry on compensation, and denotes the contractual elements required for provisioning flexibility services to optimize DER for the distribution system. We provide an inventory of contractual terms and performance components for flexibility services and a comparison of the implications of the choices for individual components. The report further explores the landscape of programs globally for comparison and awareness of best practices or pitfalls. Taken holistically, this provides a set of guidelines for MassCEC to consider in any future program/pilot development.

2 Benefit and Cost Framework

2.1 Benefits

2.1.1 Potential DER Benefits

There is a range of services that DER can provide to deliver benefits for EDCs and the wider electricity system. To explore the benefits of DER, we need to understand:

1. The **DER behavior** that can bring about a distribution network benefit (i.e., what the DER can do)
2. Under what **conditions** that DER behavior translates into an EDC-related benefit (e.g., whether the network needs to be constrained or not)
3. How that behavior **translates into a distribution-related benefit** (i.e., how the EDC or its customers benefit from the DER behavior)

As an example, let us consider the use of Distributed Generation (DG), which only generates electricity (rather than acting as a load or as storage):

- The DG can **output (export) power** onto the local distribution network.
- When the **network is importing**, this reduces network load, resulting in reduced distribution losses. If the **network is import- (demand-) constrained**, the DG may reduce peak load,
- Reduced losses will ultimately be passed through to customers in their utility bills.

The benefit of peak load reduction can be realized in several ways:

- Deferring or avoiding investment that the EDC would otherwise need to make.
- Enabling new load customers to connect to the network, which would otherwise require reinforcement.

From this example, we can see that the benefit of a DER derives not only from its behavior, but how that behavior interacts with network conditions. Furthermore, if we are to establish the benefit of that behavior, we need to define the counterfactual (i.e., what would otherwise have occurred), and be clear about who the beneficiaries are in each case.

> - **Import-constrained grid:** Region of a network where, for at least part of the year, the net demand (after local generation is considered) from customers connected at the voltages below it meets or exceed the capacity of that network. By adding DG or exporting storage, the constraint on the network can be alleviated.
> - **Export-constrained grid:** Region of a network where, for at least part of the year, the net generation (after local load is considered) from DG and batteries connected at the voltages below it meets or exceed the capacity of that network. By adding demand or importing storage, the constraint on the network can be alleviated.
>
> Note: some parts of a network can be both import- and export-constrained at different times of the day and different parts of the year.

The following subsections explore each of the DER behaviors in more detail to articulate how these translate into distribution-related benefits.

2.1.1.1 Peak load reduction

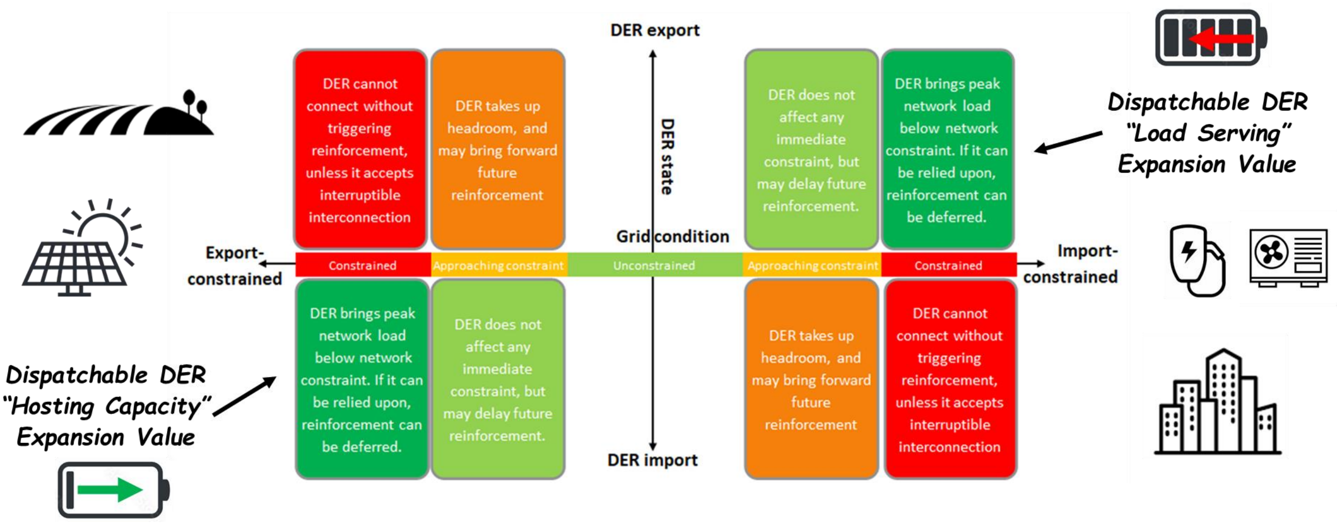
As discussed above, a key benefit – and perhaps the primary benefit – of DER interconnecting to and operating on the distribution network comes from peak load reduction, provided the DER operates in a way that is helpful to the network. If a network is, or is soon to be, import constrained, the operation of a DG unit has the potential to alleviate that constraint.

As illustrated in Figure 1, a DER can have either a positive or a negative effect on a network constraint. If the DER is acting in a 'beneficial' direction, the more constrained the network, the more valuable the DER can be. Note that this only holds if:

1. The DER is importing or exporting at a time that is beneficial to the network (e.g., during an evening peak)
2. The DER is located at the right place on the network, such that it affects loading on the constrained substation or feeder.

If a network is approaching a constraint, but is not yet actually constrained, the immediate benefit of a DER may be limited. However, assuming a future increase in network load (either from new interconnections, or from the increased electrification of existing connected customers), then the existence of a DER capable of offsetting network load can have delayed benefits.

Figure 1 - Interaction between DER action and network constraints



The impact of a DER on peak network loading is only beneficial if the network is facing an import constraint. Furthermore, the benefit may be severely limited if the operation of the DER cannot be relied upon by the EDC and factored into the network planning process.

This point is explored in more detail in Table 2, which considers the impact of a DG (i.e., export only) asset on a part of the distribution network that is importing power from the transmission network. It distinguishes between three types of benefit:

1. The benefit that arises from a **DG connecting** to an import-constrained network
2. The benefit that arises from the **DG operating 'normally'** on an import-constrained network
3. The benefit that arises from the **DG being used explicitly for the benefit of the EDC**.

Table 2 - DG impact of a solely import-constrained network

	Impact of connection	'Natural' asset behavior	Potential EDC service benefit
Benefit (or cost) created	A DG interconnection on an import-constrained part of the network may result in benefits to the network operator depending on how reliably that DG operates at times of network constraint (i.e., whether it reliably creates more headroom for additional electrical load), and how that operation is factored into the EDC's planning criteria.	The 'natural' flexibility of DG will mean that – depending on its dispatch profile – it will sometimes offset a network import constraint. Any DG export occurring when a network would otherwise be constrained will reduce curtailment/ import utilization. Its effect on the need for import availability will depend on the predictability/ reliability of dispatch.	Some types of DER can provide flexibility to the EDC on request. This can minimize the utilization of demand curtailment. More significantly, though, by increasing the predictability and reliability of export, this allows the EDC to factor DG export more fully into planning and interconnection decisions. Export commitments by DG can be treated as 'firm' headroom, deferring the need for reinforcement, and allowing more demand to interconnect.
Justification for incentive	DG is more valuable to the EDC and future customers if it connects where there is – or is likely to be – an import constraint. An incentive can influence DG to interconnect in locations with grid import constraints, so that it can be used to create additional headroom.	These DG will be providing this benefit anyway (since it relates to their natural dispatch). There is little need to provide additional incentive. However, such an incentive would encourage DG to interconnect in an area.	Without an incentive, coupled with operational guidance (see Section 3), existing DG may not consistently offset network constraints. The incentive can be tied to commitments by DG to export when required. DG would need to opt in to receive this incentive.
Incentive options *(this is explored in more detail in Section 4)*	• Discount on interconnection cost • Discount on Use of System charges • Enhanced discounts/payment subject to guaranteed export at peak times • Size of discount linked to how close the network is to being constrained	• Derated annual capacity payment based on typical export at constrained times • Payment based on post-hoc assessment of export during periods of grid constraint	• Payment for guaranteed export (regardless of whether additive to 'natural' behavior) • Generation turn-up service payment (compared to defined baseline export) • Availability and/or utilization payments • Downside for non/under-delivery

2.1.1.2 DER dependability/bankability

It is not enough to assume that a DER <u>can</u> operate in a 'beneficial' direction during periods of network constraint. Rather, the EDC must be able to rely on the fact that the DER <u>will</u> operate in that beneficial direction when required. If this is not the case, it is unlikely that network planners will be able to change their network reinforcement plans. Similarly, it is unlikely that the EDC will be able to offer up any additional headroom to other potential connecting parties. If reinforcement cannot be delayed, and if additional connections cannot be enabled, the peak reduction may be of limited practical benefit.

One way to frame this is in terms of the 'derating factor' that can be applied to an asset. This refers to the downward adjustment that an EDC may make to an asset's nominal output to account for the risk of non-delivery. For example:

- **5 x 1MW** batteries may have a **40%** derating factor, meaning that the 5MW nameplate capacity is reduced to **3MW** for the purpose of network planning (i.e., the amount the EDC can rely on)
- **10 x 0.5MW** batteries would have the same nameplate capacity, but may have a lower derating factor, say, **30%**, meaning that the derated capacity would be **3.5MW**
- **1 x 5MW** battery may be reasonably reliable, but if it is the only flexibility provider it is likely that an EDC cannot assume it will always be available when required, so may need to apply a **100%** derating factor, i.e., treat it as providing **0MW** of reliable flexibility response.

The more control the EDC has over the DER behavior – whether that control is physical or contractual – the less of a derating factor needs to be applied.

Table 3 - Effect of commitment level on DER value to the EDC

	No commitment	Contractual commitment	EDC control
Description	DER do not commit to any particular availability or dispatch behavior	DER commit to certain behaviors for the duration of the contract	DER allow EDC to control the behavior of DER assets remotely
Derating factor	High derating applied since DER cannot be guaranteed to operate in a beneficial direction during times of network stress. EDC must rely on how the DER is expected to behave.	Medium derating can be applied. The EDC has commitment and some recourse for non-delivery but cannot guarantee network integrity to the same degree as can be achieved through network reinforcement.	Low derating can be justified, since EDC can control DER remotely.
Possible mitigations	Large numbers of small DER might justify a lower derating factor, since their average behavior would be more predictable than any single DER. However, if those DER are providing other system services, there is still a risk of herding behavior that could be to the detriment of the network.	Degree of confidence that the EDC can have in the DER will depend on the contractual terms and the credibility of the DER entities. A combination of stringent eligibility criteria and non- or under-delivery penalties would improve the dependability of DER from the perspective of the EDC, although a single DER is still unlikely to be sufficiently reliable for EDCs to depend on.	Even with remote control, unless the EDC owns and operates the DER asset, it cannot guarantee that it will not be offline or unavailable. If the EDC requires import/export on demand, it still carries some risk, therefore. It can, however, be confident of curtailing the DER as a failsafe (i.e., avoiding the DER exacerbating a network constraint).
Value to the EDC	None, since it is unlikely that DER can be relied upon sufficiently to defer or avoid conventional network reinforcement.	Low - Medium, since it may be possible to rely on DER to the extent that conventional reinforcement can be deferred, although the EDC may need to over-procure to minimize the risk of under-delivery.	Medium to high, depending on whether the EDC is planning based on its ability to curtail the DER, or whether it is depending on DER import/export as part of the EDC's planning assumptions.

The above assumes that the EDC is directly relying on a DER as a means of avoiding or deferring conventional network reinforcement. However, if there are connected customers currently on, or willing to be on, non-firm or interruptible connections, there may be an alternative mechanism by which these DER can create value for the system.

For example, consider a solar farm with an interruptible interconnection. It must curtail its output when the local network is constrained. If we assume that it is curtailed for 50 hours per year, this represents a loss of revenue for this operator, and a loss of low-carbon energy for the system. A single battery interconnecting in the same area could reduce the need to curtail this solar asset by acting as a load during times of network constraint. If the battery failed to operate during a period, the solar asset would still need to be curtailed. In either case, the integrity of the network would be unthreatened. Because the operation of the battery is not critical to secure network operation, the derated capacity can be assumed to be higher than 0MW (i.e., the derating factor does not need to be as harsh as 100%).

In this case, the benefit of DER would not come from delaying reinforcement or enabling new interconnections. Rather, the benefit derives from reducing the curtailment that a non-firm customer would expect to experience. This assumes that the non-firm connection involves dynamic curtailment linked to active constraints, rather than time-varying access agreements.

Whether that benefit accrues to the customer or to the EDC would depend on whether that curtailment is compensated in any way. In either case, by reducing curtailment of a third party, the DER has the potential to provide a benefit by exporting during import constraints or importing during export constraints.

2.1.1.3 *Reinforcement deferral vs hosting capacity creation vs curtailment reduction*

There is a distinction between export peak reduction that defers reinforcement, and export peak reduction that enables additional generation interconnection to occur. The two cases can be summarized as follows:

- **Reinforcement deferral**, where DER flexibility can be factored into the planning process and allows the DER to reduce network load, and thereby to delay or avoid the need to reinforce the network because of thermal constraints.
    - If 'organic' load growth is creating a network constraint, an EDC will have to reinforce and incur the resulting costs. The DER defers the point at which that constraint would trigger a network upgrade and saves money for the EDC and its customers.
- **Hosting capacity creation**, where flexibility allows the network to accommodate new generation interconnections.
    - If a network has no 'organic' load growth, but a new customer wishes to interconnect, and doing so will push the network outside its operating limits, there is opportunity for a connecting DER to create headroom. The EDC could allow the new customer to connect without triggering network reinforcement, which would save money for the interconnecting party.

In both these cases, the savings that result from the reliable dispatch of the DER relates to the avoided reinforcement cost. The difference relates to which entity would have been responsible for incurring those costs. In the first case, the utility and its customers pay for reinforcement, so they are the beneficiary of flexibility use. In the second case, the developer pays for interconnection-related reinforcement, and so the developer benefits from the use of flexibility. The distinction, therefore, may be one more of benefit allocation, and may feed into the discussion around compensation mechanisms, which is explored in more depth in Section 4**.**

There is a third possibility where DER peak reduction can result in a benefit – curtailment reduction.[2]

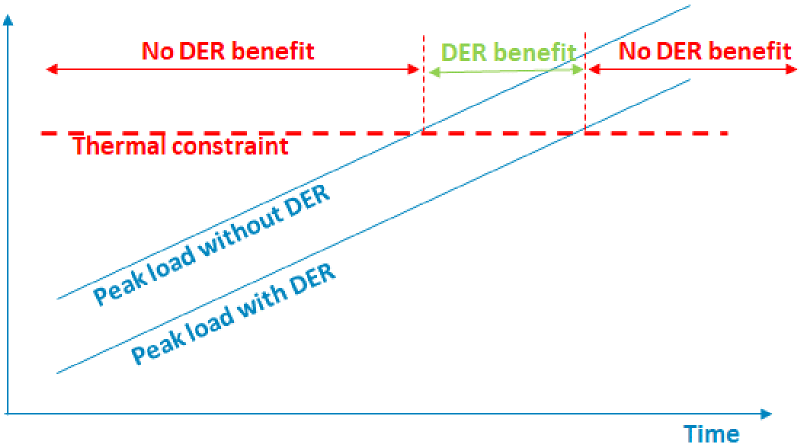
If the network is already at capacity, it may still be possible to interconnect new customers who desire to utilize the network for exporting power from a DER under non-firm arrangements. Under non-firm interconnection, the customer would have access to the network for export from their DER if and only if the network is not constrained. If the peak network load reaches the network capacity, these customers are required to flex their generation. In such a situation, the operation of a DER can serve to reduce the curtailment experienced by these non-firm customers. Depending on whether this curtailment is compensated, the benefit of the DER would accrue either to the customer (through reduced curtailment) or the EDC (through reduced compensation payments).

2.1.1.4 Avoidance of future constraints

As described in Figure 1, a distribution network may not be constrained today, but may be on a pathway to being constrained in the future. In this context, it is not clear whether peak reduction from a DER is beneficial. In the short-term, peak reduction provides little benefit to the distribution network since reinforcement is not being triggered whether the DER is operating or not. However, if the peak network load is increasing over time and will be reinforced in the future, then the existence and operation of a DER should delay that future reinforcement.

The DER in this case is only beneficial at the point in time where reinforcement would otherwise need to occur. As load further increases, if the DER can no longer defer reinforcement, the EDC will be required to reinforce the network. At that point, the value of flexibility again drops to zero. We can picture this as a step-change in the value of DER from peak load reduction, as illustrated in Figure 2.

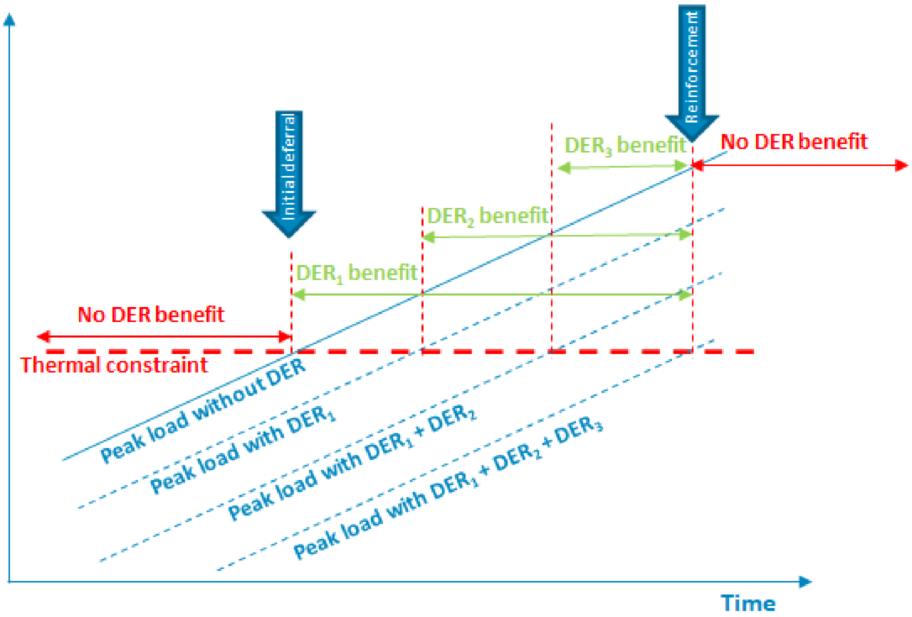
Figure 2 - Step change in DER benefit at point of network constraint



In this simplified case, the value of DER steps up from zero for a finite time, then drops back to zero. However, as the peak load increases, rather than reinforcing, there may be instances where it is economically viable to continue to procure additional flexibility. In this case, it becomes justified to procure flexibility for longer periods, at least for a subset of the DER, as illustrated in Figure 3.

[2] It is understood that this type of arrangement does not currently exist in Massachusetts in practice, and thus is illustrative to demonstrate the potential benefit that could be explored if there was appetite in the state.

Figure 3 - Extending DER benefit through consecutive and concurrent procurement



In practice, future load growth cannot be known with certainty when the first DER flexibility agreement is procured. However, by signing that flexibility agreement, this allows the EDC to defer the decision to reinforce the network (with the caveat that the EDC will likely derate the DER contribution to peak reduction, as discussed in Section 2.1.1.2). This then allows the EDC to retain the 'option' to procure further flexibility if the economics justify it (i.e., if the unit cost and required volume of flexibility do not exceed the value of reinforcement deferral). EDCs should reflect this 'option value' when agreeing on the price for the initial DER flexibility contract.

There may be further justification for securing longer-term flexibility contracts. For example:

1. **Within-year load uncertainty:** Recognising the benefit of DER only when peak load would exceed network capacity fails to recognise that peak load is uncertain and varies from year to year. There may be benefit in having DER as the network approaches a constraint because it reduces the risk that the network is pushed outside of its operating envelope (because of unforeseen weather, atypical demand, or network faults).
2. **Stability of investment signals:** Even if the underlying future load growth were known with perfect foresight, there may be a justification for reflecting the future value of DER ahead of the network becoming constrained. If a constraint-related price signal is only provided to DER when the "DER benefit" period is live, this gives no forward-looking signal to potential DER investors trying to decide where to site their projects. Furthermore, if we reintroduce the idea of load growth uncertainty, they may determine that the short-lived and uncertain nature of such a compensation mechanism is not sufficient to affect their decision-making in any meaningful way.
3. **Capital delivery pipeline management:** Flexibility can help to improve the deliverability of capital plans. For instance, it may take 7 years to build a new substation. Using DER flexibility can help to bridge the gap if load growth occurs too quickly over that 7-year period, ensuring that the old equipment is not overloaded while new equipment is being deployed.

There is an argument, then, to provide DER with a constraint-related price signal that increases in increments as a network becomes more constrained. This may not be tied strictly to the immediate benefit that the DER brings to the network. Rather, it creates a consistent signal to potential DER investors to site their developments in areas that have the potential to benefit from their presence.

2.1.1.5 Voltage management

A DER may be able to support the EDC in managing the voltage levels on its network. For example, the voltage on a long feeder will tend to drop, requiring additional transformers or voltage regulating devices to be installed. By injecting current along such a feeder, well-sited DG has the potential to mitigate this voltage drop and reduce the need for such network interventions. DG can also absorb or inject reactive power.

The benefit of DER in such situations can be viewed in three categories:

1. **Requirements placed on the DER** at the time of interconnection, including its reactive power capabilities and grid code obligations.
2. The benefit of the **DER in 'normal' operation**, which is to say the benefit that comes from the DG operating in line with its default regime, with no consideration for the benefit or cost to the EDC.
3. The benefit of the DER providing a **service to the EDC**, such as a reactive power service on instruction.

The value of DER voltage management to the EDC, therefore, relates to which of these categories of benefit can be realized. Furthermore, the benefit will depend on where the DER is sited, and its ability to address any given voltage issue. As with the **peak load reduction** benefit, the voltage management benefit will only arise if the DER is in an appropriate location.

However, voltage management is more location dependent. This is because a DER needs to be topologically close to a voltage issue to alleviate it. When assessing the benefit of a DER, then, the EDC will need to understand not only whether the DER is connected to the appropriate feeder, but how close it is situated relative to the points on the network that require voltage management. In Great Britain (GB), National Grid refers to this concept as the 'effectiveness' of a DER relative to a point on the network, which is expressed in its reactive power procurement process as a 'sensitivity value': "Sensitivity value is an indicator of the effectiveness of a DER reactive power injection in a particular [Grid Supply Point]".[3]

2.1.1.6 Avoidance of distribution losses

The operation of DER has the potential to reduce the bulk transfer of power from transmission-connected generators to distribution-connected consumers (assuming that DER are located close to demand sites and are comparable in size or smaller than those demand sites, which will not always be the case). As a result, the losses associated with this transfer of power can be avoided. Because of the square relationship between current and losses (i.e., I^2R), if peak loads can be reduced, the effect on losses can be significant.

The effect of a particular DER on network losses will depend on the load characteristics of that DER, where on the distribution network it is (e.g., in relation to loads), and the power flows that occur with and without the DER in place. It may be difficult, therefore, to generalize the impact. However, studies of other networks have suggested that the loss reduction associated with DER can be significant, as shown in Figure 4.

[3] https://www.nationalgrideso.com/document/168076/download

Figure 4 - Impact of CHP and PV on distribution network losses (SOURCE: UK DTI)[4]

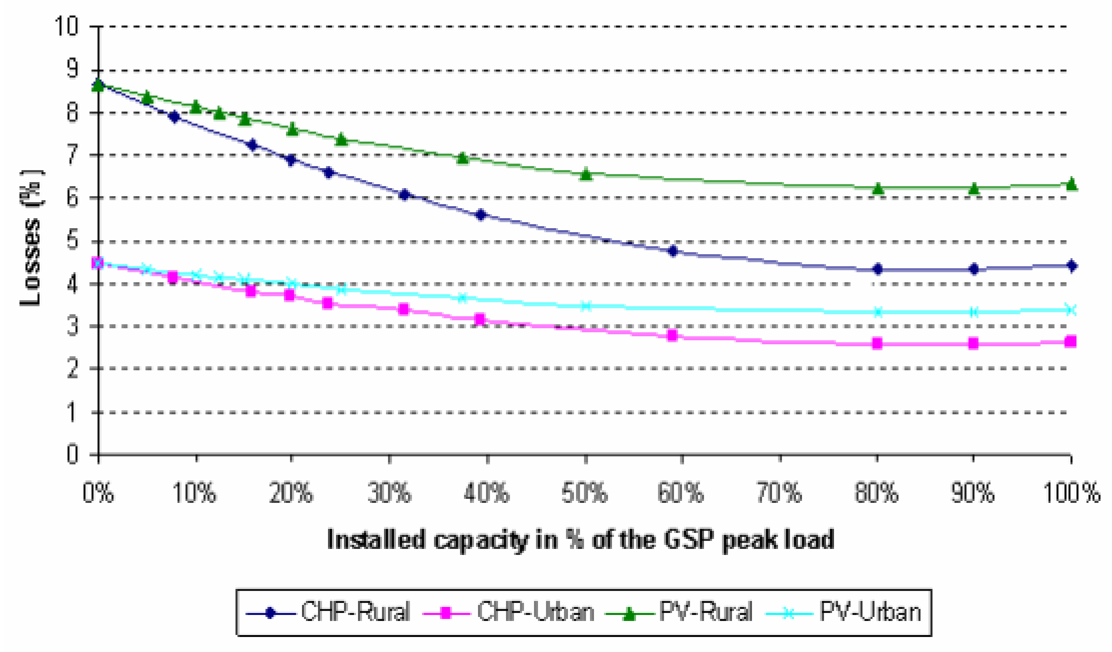


Figure 4 is only illustrative and refers to analysis of losses completed on the United Kingdom (UK) grid. Analysis of Massachusetts would no doubt show different values (both in terms of the starting losses and the reduction that can be achieved), so further study would be required before monetary benefits could be calculated.

2.1.1.7 Resilience/islanding

The DER has the potential to provide resilience in the event of a network fault. The scope of this study is limited to larger DER that are not co-located with load. As such, these assets cannot provide on-site backup. Nevertheless, it may be possible to operate these assets as part of a microgrid in the event of a fault at a higher voltage on the distribution or transmission network.

It should be noted that 'islanding' is generally viewed as an undesirable outcome in the event of a network fault, leading both to asset protection issues and presenting a significant danger to maintenance crews. As such, a range of anti-islanding and islanding detection measures are typically put in place:

> *IEEE 1547 requires any Distributed Generator (DG) on a distribution feeder to be detected and be tripped offline within 2 seconds upon formation of an island from the Area Electric Power System (EPS). An island is a condition in which a portion of an Area EPS is energized solely by one or more Local DGs while it is electrically separated from the rest of the Area EPS.*[5]

However, 'intentional islanding' is possible:

[4] DTI Centre for DG and Sustainable Electrical Energy: Integration of DG into the UK Power System (https://www.ofgem.gov.uk/sites/default/files/docs/2007/07/dgsee_ewp_dg_value_paper_v3_0_0.pdf)
[5] https://www9.nationalgridus.com/non_html/DG_CHP_Seminar.pdf

One alternative method of network management is intentional islanding, which relates to when an area of network is intentionally disconnected from the grid supply and local assets such as generation and storage are used to independently support a managed set of flexible demand [9]. Intentional islanding has numerous benefits, though, typically the primary function is to ensure security of supply in the event of an outage.[6]

While there are theoretical benefits to intentional islanding, it can only be done if a range of potential safety, security, and legal issues can be addressed.[7,8]

2.1.2 Literature Review | What benefits have other countries considered?

A detailed literature review was completed to leverage work that Baringa has done with the UK regulator, Ofgem, as well as work experience in other markets in the US and Australia. The detail on this review can be found in Appendix A.

This review highlights several potential sources of value (or cost) for the EDCs and its customers associated with the interconnection and operation of DER. These are:

1. **Network peak load reduction:** A DER has the potential to reduce peak load, and thereby alleviate an existing, emerging, or future network constraint. This may be used to defer or avoid network reinforcement that might otherwise need to occur. Alternatively, it may be deemed to create headroom that can enable other customers to interconnect using the available headroom.
2. **Voltage management:** A DER can provide voltage support either by absorbing or supplying reactive power to maintain the required voltage profiles on the network.
3. **Avoidance of distribution losses:** By increasing DER generation near to loads, the distance over which energy travels can be reduced, thereby reducing losses on the distribution network.
4. **Distribution network reliability/islanding:** Provided it can be done safely, DER can be used to supply local networks following faults, reducing the volume of unserved energy and the duration for which they occur.

There may be other impacts that DER can have on the distribution system. For example, fault current levels – which allow EDC system protection equipment to operate to safely isolate equipment during a disturbance – can be a limiting factor for the interconnection of some customers, so the impact of a dispatchable DER on fault current level could be seen as a cost or a benefit. This has not been raised in the literature reviewed to date but may warrant further consideration.

Other benefits deriving from DER relate to non-distribution impacts including:

- **System/generation**: DER can displace energy that would otherwise be injected into the distribution network, and the installed generation capacity required to provide that energy. In addition, DER can provide ancillary services such as frequency response.
- **Transmission**: Most of the impacts of DER on the distribution network can have a similar impact on transmission, including affecting peak load (and hence the need for investment) and affecting losses.
- **Environmental/societal**: DER can affect the carbon intensity associated with operating the electricity system, for example, by displacing high-carbon forms of generation. There can be other environmental impacts (both positive and negative) in terms of local pollution and disruption.

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[6] https://strathprints.strath.ac.uk/77196/1/McGarry_etal_RPG_2021_Decarbonisation_of_rural_networks_within_mainland_Scotland.pdf
[7] https://electrical-engineering-portal.com/protection-impacts-intentional-islanding-distributed-generation
[8] https://www.nationalgrid.co.uk/downloads-view-reciteme/55615

These impacts do not constitute distribution benefits, and as such are not the focus of this study. However, they do need to be considered because they can affect the wider incentives that DER face, and hence the dispatch behavior of those DER.

2.1.3 What benefits are most appropriate for EDCs in Massachusetts?

Following discussion with the EDCs and stakeholders, it has been determined that some benefits are more appropriate – at least at this stage – to focus on, and potentially introduce in the form of a demonstration project.

Table 4 - Proposed prioritization of network benefits

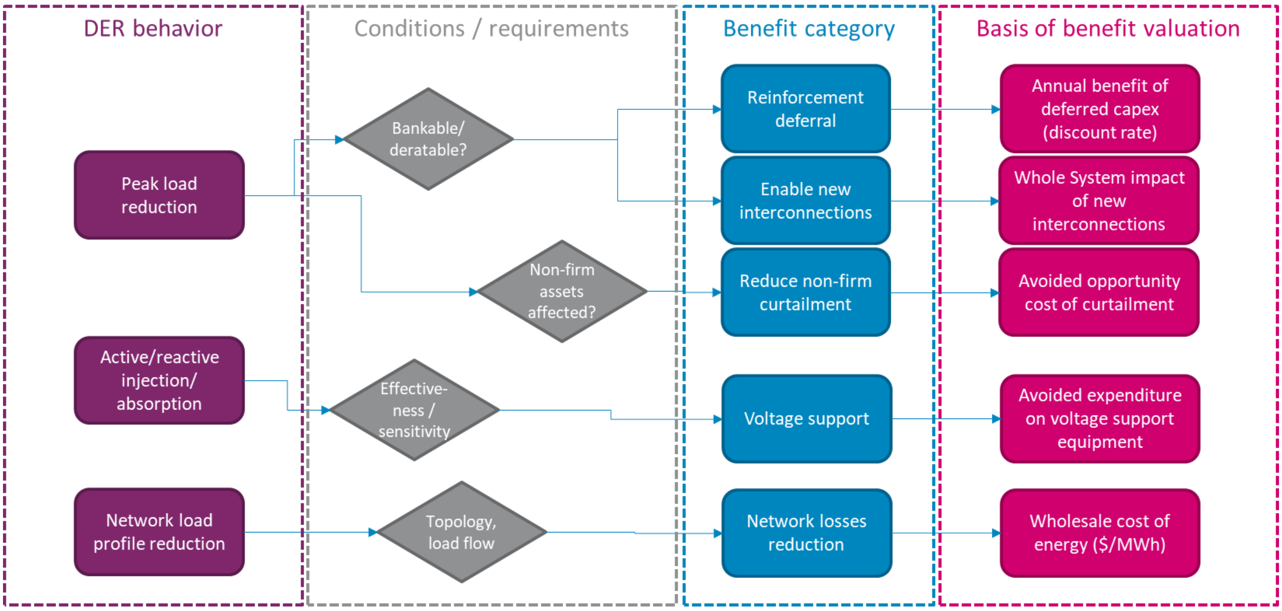
Network benefit	Proposed priority	Justification
Network peak load reduction	High	This should be the primary focus, as it has the most expected value for the EDCs and customers, can be relatively easily defined and measured, and can draw on a range of case studies from other geographies.
Voltage management	Medium	Just as some parts of the network are thermally constrained, others are voltage constrained. In that sense, then, there is value in recognizing and incentivizing the voltage-related benefits that DER can deliver. However, across the international examples, the markets for voltage and reactive power services are more nascent. Furthermore, it is more complex to implement such markets, particularly because reactive power is more location-specific than active power. This means that DER need to be close to a voltage constraint to help alleviate it, which limits the pool of participants. Furthermore, the value of a DER to the EDC varies according to the DER's proximity to the constraint, which makes calculating the acceptable compensation rate more complex. So, whilst there is an argument for recognizing the voltage-related DER benefit, it may be prudent first to develop the active power flexibility service.
Avoidance of distribution losses	Low	Whilst technical losses reduction is a real potential benefit from DER, there are three reasons to de-prioritize it: i. The expected impact is small when compared to the benefits of, say, reinforcement deferral. ii. EDCs are not incentivized to reduce technical losses at present. iii. Measuring the impact of DER behavior is challenging and varies depending on the location of the DER and the loading on the network at any particular time. For these reasons, the proposal is to deprioritize this benefit.
Distribution network reliability/ islanding	Medium	The ability of DER to enable intentional islanding and provide resilience to – in particular more remote – networks is reasonably well established. However, its implementation internationally is still in the early stages, with some trials occurring, but little in the way of transition to business as usual. It may well be appropriate to ascribe DER benefit in this area but doing so would first require a trial to understand how it would operate, what the technical and commercial requirements would be, and what value individual DER could bring.

2.1.3.1 DER benefit decision tree

The interconnection and operation of DER on the distribution network can have a range of benefits for the EDC and its customers. To estimate the value of a particular DER, therefore, the EDC will need to consider whether and to what extent that DER contributes to one of the benefit categories.

Figure 5 shows a high-level DER value decision tree. This illustrates how the EDC might think about the value that a DER delivers. As it shows, the benefit depends not only on the DER behavior, but also the condition of the network and the extent to which the DER behavior can be 'banked' by the EDC in its network planning and interconnection process.

Figure 5 - DER value decision tree



2.2 Needs and Services

As outlined in Section 2.1, the benefits that are available are high level, and the value that a particular DER provides will be determined by considering whether and to what that DER contributes to a benefit category. That can be determined by understanding and articulating the specific network need that would allow each benefit to be accessed, and how EDCs would meet that network need – by procuring or contracting a service. These are articulated below in an illustrative example.

To access the benefit of deferring network reinforcement into the future, the specific need is to delay reinforcement to a time that it is clearer that an upgrade is needed. For example, say there was a specific substation that, based on load growth projections and hosting capacity analysis, had a specific window (e.g., 3-6pm) with consistent thermal constraints, where firm capacity was exceeded in that period in the winter months. The need would be to reduce thermal load in that window, in the months where it was overloading. This need could be met by either upgrading the substation (counterfactual) or utilizing a flexible DER to reduce the thermal constraint within that specific timeframe for a certain period. The DER would be providing a service that would meet the specific need of the network, enabling benefits to be realized.

Whilst we have identified Network peak load reduction as being the primary benefit to EDCs from DER, within this category different valuation approaches may be applicable. This section explores, at a high level, how the benefit might be realized by the EDC, as summarized in Table 5.

Table 5 - Basis of benefit valuation by benefit category

Benefit category	Basis of benefit realization
Reinforcement deferral	• The benefit of reinforcement deferral can be expressed in terms of the extent of the deferral and the time value of money ('discount rate'). The total expenditure associated with reinforcement needs to be accounted for, including transformer upgrades, substation works, and feeder reinforcement. • Where there is load growth uncertainty, DER flexibility can provide additional upside with limited downside because of the 'option value' of flexibility. • Some downsides can occur depending on how DER flexibility is implemented, including increased outage risk and increased asset maintenance.
Enable new interconnections	• Additional headroom allows new generation customers to interconnect. The value in this case relates to the avoided opportunity costs of being unable to interconnect in the desired location at the desired time. • Opportunity cost will vary depending on the site, the demand for new interconnections in the area, the type of site and the geographical fungibility (i.e., how important it is that the interconnection occur at a specific site) • Precise value can only be known by estimating the developer Willingness to Pay for a new interconnection, but some generic proxies could be developed.

Reduce non-firm curtailment	• In this case, DER operation reduces the curtailment of assets under non-firm interconnections (assuming these exist)
	• The value of the DER is linked to the avoided opportunity cost associated with that curtailed energy.
	  ▪ For a non-firm DG, this will relate to the impact of the curtailed energy on the wholesale price, plus any additional cost of the non-firm DER being unable to provide system services.
	  ▪ For non-firm demand (which we would assume has on-site supply options), the cost will relate to on-site generation costs and potentially improved security of supply.

To realize any benefits from thermal constraint reduction, there are changes that EDCs would need to make to internal processes which would require investment, which we explore in Section 2.3.

2.2.1 Integration into utility planning process

There are several key enhancements to utility planning processes that are critical to creating clarity on network needs and are enabling capabilities for the EDCs to develop.

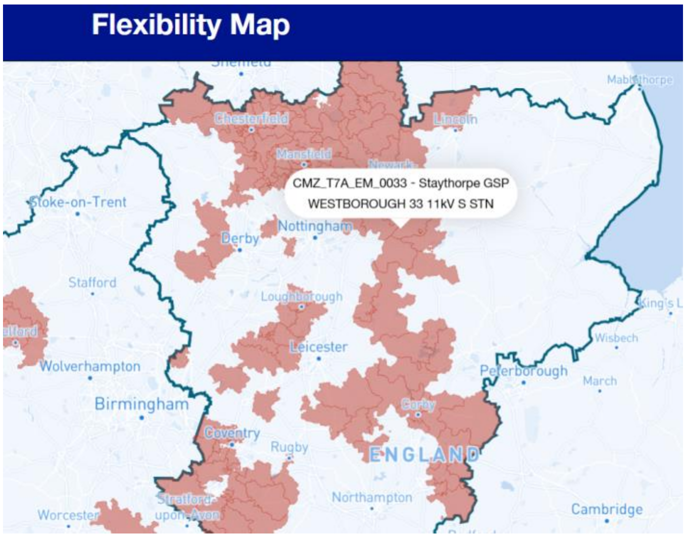
- **Interconnection studies**: Current interconnection studies could potentially evolve to incorporate a more flexible connection, such as a 'dynamic operating envelope'.[9] Dynamic operating envelopes were explored in the Australian case study explored in depth in Appendix A.2, and allow the EDC to determine the amount of capacity that is available on a distribution network at the feeder or substation level, and then define the range of power transfer capacity (generation and load) that can be allowed at each DER connection point without violating distribution system thermal and voltage

[9] Eversource has already proposed operating envelopes and is planning to implement in business as usual.

limit. Communicating this information during interconnection studies would allow for more flexibility for the DER connected whilst respecting grid needs and safety concerns. There are several ways in which this could be facilitated, which would need to be designed as a part of the interconnection process.

- **Hosting capacity maps**: Current hosting capacity maps account for solar alone, so additional information would be required to make this relevant for storage solutions. Constraint information can helpfully be shared as a part of a heat map, such as that utilised by National Grid at the distribution level in the UK[10], as demonstrated below in Figure 6. These would need to build on existing hosting capacity maps to include additional information such as size or impact of group studies and queue, system constraints/thresholds before applying to interconnect, location and nature of constraint (import/export), if seasonal, windows, real-time and forecast constraints, and advanced notice of curtailment

Figure 6 - National Grid Distribution 'Flexibility Map'



- **Diversity**: Over time as more DER connect to the grid, it is likely that diversity of load (and generation) connected at the feeder and/or substation level will increase. This reduces the need for EDCs to consider a singular asset to provide flexibility and will need to be accounted for as a part of planning capability and interconnection studies. Increased diversity could provide increased reliability, as the risk of reliability of service provision could potentially be spread across several assets. Planners will need to consider diversity factors and suites of assets when considering how DER can address load or generation constraints.
- **Consideration of option value**: An approach for considering optionality was captured as a part of the work Baringa did with the Energy Networks Association (ENA) in the UK, to develop a Common Evaluation Methodology (CEM) for EDCs to utilize when evaluating network investment options. This is explored in more depth in Section 4.2.1

2.3 Costs

There are several costs that would need to be considered as a part of the BCF that fall into three categories:

[10] https://www.nationalgrid.co.uk/network-flexibility-map-application

- **Cost of operating a distribution-level service**: The EDCs would incur costs to operate a new service at this level that span the end-to-end process from planning (e.g., more detailed hosting capacity analysis), to procurement (e.g., new way of running NWA process or a procurement platform), to operating the service (e.g., metering solutions and dispatch platforms). These will be explored in more detail in Section 2.3.1.
- **Opportunity cost of investing in network reinforcement:** There is an opportunity cost to the EDC of investing in network upgrades now, rather than using a flexibility resource to defer investment to a later period when it is known with greater certainty whether the investment is needed. As discussed in the Benefits section, the combination of uncertainty and irreversibility of this decision creates the 'option value' of using flexibility from a DER as an alternate option to network reinforcement.
- **Cost to the developers of providing flexibility:** Any DER developers that would be providing a service to the distribution-level market would incur costs to do so (e.g., interconnection costs, demand charges, energy charges, operating costs). We explore these and the risks associated below in Section 2.4.

As applies to the benefits outlined in Section 2.1, not all these costs would be incurred in each case. These would vary depending on several factors, e.g., the site and network need, upgrade costs, platform costs that might vary across EDCs etc. These would need to be modelled and applied to any analysis on a case-by-case basis.

2.3.1 EDC Costs

Some utilities are taking a conservative approach to investing ahead of need given the nascent nature of distribution-level markets for DER. This approach consists of investing in a simple DER registration system which funnels interconnections through today's study processes, paired with a stand-alone DERMS platform to dispatch the DERs when required. Integration and streamlining on the control side may go as far as finding a DERMS platform that can interface with a few standardized or even proprietary protocols. There are often additional incremental improvements to the forecasting group to be able to better predict embedded generation, in other words predict net load rather than pure load.

Using this approach there is little to no cost for operational framework improvements. However, to adequately prepare for the scale of change required to create a fully operational, end-to-end system operation function at the distribution level, there are several key areas that require investment from the EDCs.

2.3.1.1 Registration

Registration systems would ideally be integrated with the entire utility infrastructure. Key to this is the ability to perform periodic assessments of capabilities of DERs to update them as they age and evolve. Links to operational systems for feedback, in addition to being able to track updates from participants are all beyond the scope of the current state-of-the-art. Related to this, improvements to GIS are needed to model the DERs grid behaviors. Over time this could evolve into a more sophisticated grid modelling software suite initialized with EDC GIS data and further augmented with additional sources of electrical connectivity and behavioral data from the DERs themselves.

2.3.1.2 Planning

Planning departments are likely to require significant investment to fully integrate into a functioning distribution market. Planning tools need upgrades to not only evaluate interconnection options more dynamically, but there also needs to be several different "paths" to follow based on the (a) size of the DER and (b) capabilities to sort out differences among flexible demands, distributed generation, or controllable storage. As time progresses, there is going to be an increase in the number of DERs, but it is likely that more DERs will become "off-the-shelf" with little or even no knowledge of the utility of their deployment. Low-voltage EV chargers are a perfect example of DERs that needs to be "sensed" rather than "interconnected".

2.3.1.3 Markets

Wholesale electricity market designs are advanced in the United States, as are some European markets. Very few of the design elements have been applied to distribution systems, though many of the concepts can be applied without significant alteration. Many of the DER markets at the distribution-level are relatively crude and tend to be governed by a locally designed program which may (or may not) resemble programs in neighboring jurisdictions. This is far away from a system which prices services on each feeder on a day-ahead timeline, with more real-time corrections made based on system conditions. Better yet, price coupling to the wholesale energy markets would reduce the sharp market boundaries and could allow for more efficient utilization, i.e., more opportunities for revenue stacking.

Today, distribution services are not well defined, and the focus is almost exclusively on energy rather than potentially more lucrative future grid services. Plans from the regulator in the UK, Ofgem, and the Energy Networks Association (ENA) in the same region have made significant progress in this area and are worthy of consideration. These are discussed in detail in Section 4.2 and Appendix A.

In addition to the costs of developing and designing market structures, there are costs to build, operate and administer market platforms, which will be significant. There are trials of such structures ongoing, which are discussed in Section 4.2

2.3.1.4 Forecasting

Traditional "load forecasting" groups will need to evolve their capabilities into "energy forecasting" groups. New forecasts need to include not only traditional factors (seasons, day-of-week, time-of-day, weather, planned outages, etc.), but more importantly vary the forecasts based on the market design so that static estimates can be replaced with price-sensitive ones that are coupled with potential market signals variations. EDCs should be aiming for short-term, local forecasts that match the level of granularity of the distribution grid services that will be dispatched.

EDCs will incur significant cost in terms of people, process, data, and technology to evolve these capabilities.

2.3.1.5 Controls

In most cases, utilities today are looking at controls using a demand response style mechanism with standardization focused on inverter settings to coordinate system protection. Very little thought has been given to how controls that "influence" behavior might be designed and operated, as opposed to hard-wiring rigid control schemes. Programs linked to these dispatches seem to be manually triggered and controlled via manufacturer system APIs, rather than new-frontier aggregators interacting with the utilities in a more asynchronous, open, standards-based method. Whatever mechanisms are established will likely be highly correlated with the market design which will steer signals either towards a more traditional control scheme or a market-based asynchronous one. This is not a significant area of cost as dispatch capability is baked into existing DER systems and will largely rely on market design.

2.3.1.6 Operations

Real-time systems will need upgrades, but if many of the systems and processes outlined above are put in place much of the burden of real-time controls for DERs should be passive. Like wholesale markets which hum along on most days without much need for the operations staff to alter dispatch points manually, distribution control rooms will need more flexible contingency schemes to manage local events when market processes reach their limits and to incorporate DERs as restoration services. This will be important for both the local/feeder/microgrid level as well as part of system-wide support plans.

2.3.1.7 Measurements/Billing

It is likely that as markets evolve, the way that utilities will bill customers will fundamentally shift. Costs will be incurred for new accounting systems, but the bigger challenge is one of regulatory tariff reform.

In summary, there are major potential changes to the ways EDCs operate in a world with many DERs on the distribution systems. While these changes are unnecessary to operate a small number of large DERS, ignoring the need for these systems is probably not the optimal strategy. Any upgrade to systems and processes that is necessary to facilitate large-scale, small DERs can also be leveraged in the short term for the ones currently being considered.

2.4 Developer Costs

There are several major categories of costs and associated risks that developers would incur to participate in distribution-level services, as outlined below.

- **Interconnection costs**: As a part of the interconnection process, EDCs pass on the costs of accommodating interconnection to the grid to the developers. This is completed as part of an interconnection study, where analysis is done on assumed battery operation to analyse the impact on the grid, and the cost associated to accommodate such behavior..
- **Operational & maintenance costs**: Developers will incur costs to operate and maintain their DER assets, which include people, process, data and technology, as well as accounting for losses between charging and discharging.
- **Demand charges**: Connected assets will pay for energy consumption at a point in time based on peak usage, on a kW or MW basis depending on the size of the asset.
- **Energy charges**: Connected DER will be charged a retail energy tariff based on the total amount of energy consumed over a period, on a kWh or MWh basis.
    - Currently in Massachusetts, storage solutions are treated as load by EDCs, and as a result are charged load tariffs for both charging and discharging the battery. As a result, the business case for battery economics is uneconomical as the costs are not offset by revenues. There are ongoing discussions around reform of retail rates for storage solutions that involve the EDCs and the developer community as a part of the Wholesale Distribution Tariff Working Group. Specifically, this working group has proposed a cost-of-service based rate that is focused on ESS and similar DER participants in wholesale markets.
- **Opportunity cost**: Depending on how the service is designed, a connected DER will likely incur the cost of foregone revenue from non-participation in its current stack of revenue streams.
    - For this reason, unless the service is designed to be perfectly stackable with existing revenue streams, this opportunity cost will play a key role in determining the required price for distribution-level services.

- In the case of a standalone storage asset in Massachusetts, the most prominent revenue streams include the state's Clean Peak Standard and wholesale power market services provided by ISO New England. Greater detail on these revenue streams is provided below.

Further insight on developer views of their costs and risks is included in our stakeholder insights in Section 5.

2.4.1 Revenue streams for storage assets

To further expand on the discussion around opportunity cost presented above, Figure 11 provides a detailed breakdown of the revenue streams available to DERs in Massachusetts.

Table 6 - Existing revenue streams for battery storage assets

	Revenue Stream	Description	Duration of Service Provision	Valued in MA Electricity Markets
Federal Policy	**Investment Tax Credit (ITC)**	The base ITC rate for storage is 6% with a bonus rate at 30%. The bonus rate is available if the project is less than 1MW or if it meets prevailing wage and apprenticeship requirements	NA	Yes
State Policy	**Clean Peak Standard (CPS)**	A market-based mechanism whereby eligible resources generate Clean Peak Energy Certificates (CPECs) based on their metered output during daily, pre-determined, 4-hour Seasonal Peak Periods. CPEC volume is dependent on multipliers that vary by hour, season, and resource type. The highest multiplier (x25) is applied during actual monthly system peaks	Daily + Hourly for maximum revenue, similar to existing energy arbitrage schedule	Yes
State Policy	**Solar Massachusetts Renewable Target Program (SMART)**	Solar assets receive a fixed $/kWh payment on energy produced for 10-20 years. Solar + Storage is eligible for an additional $/kWh 'adder'.	Paid by $/kWh w/o temporal or locational factors. Program requires 52 cycles per year	Yes
Wholesale Markets (ISO-NE)	**Forward Capacity Market (FCM)**	Annual resource adequacy auction held three years in advance of the operating period. Annual and monthly reconfiguration auctions are also held in which participants can alter their capacity supply obligations. Revenue in FCM is composed of Capacity Base Payments (availability) and Capacity Performance Payments (CPP or PFP). Settlement for PFP is based on performance relative to the resource's capacity obligation during reserve deficiencies. These conditions typically occur around twice per year for around 1-4 hours each. Resources with a capacity obligation can be severely penalized for non-performance during scarcity events	Requires 2-hour discharge capacity for full, inverter rating, capacity accreditation. Performance events are rare, though the asset may be subject to an annual capacity audit.	Yes, via resource adequacy payments and penalties to non-performing assets
Wholesale Markets (ISO-NE)	**Energy Market - - Arbitrage**	Hourly price arbitrage via the purchasing of low-cost off-peak energy shifted and sold during higher on-peak pricing hours	Daily + Hourly for maximum revenue	Yes, with revenue potential expected to grow in ISO-NE as renewable expansion drives greater price variance

	Revenue Stream	Description	Duration of Service Provision	Valued in MA Electricity Markets
	Ancillary Services	Includes services such as Frequency Regulation, Spinning Reserve, Forward Reserve, and Voltage Stability, of which Frequency Regulation typically provides the greatest revenue potential for storage assets in MA	Durations between seconds to hours depending on the product. Regulation is cleared each hour and provides a significant revenue stream for storage assets	Yes, though markets are small and at risk of saturation with further storage deployment

These revenue streams can be loosely allocated into three key categories:

- Federal Policy
- State Policy
- Wholesale Power Markets (ISO-NE)

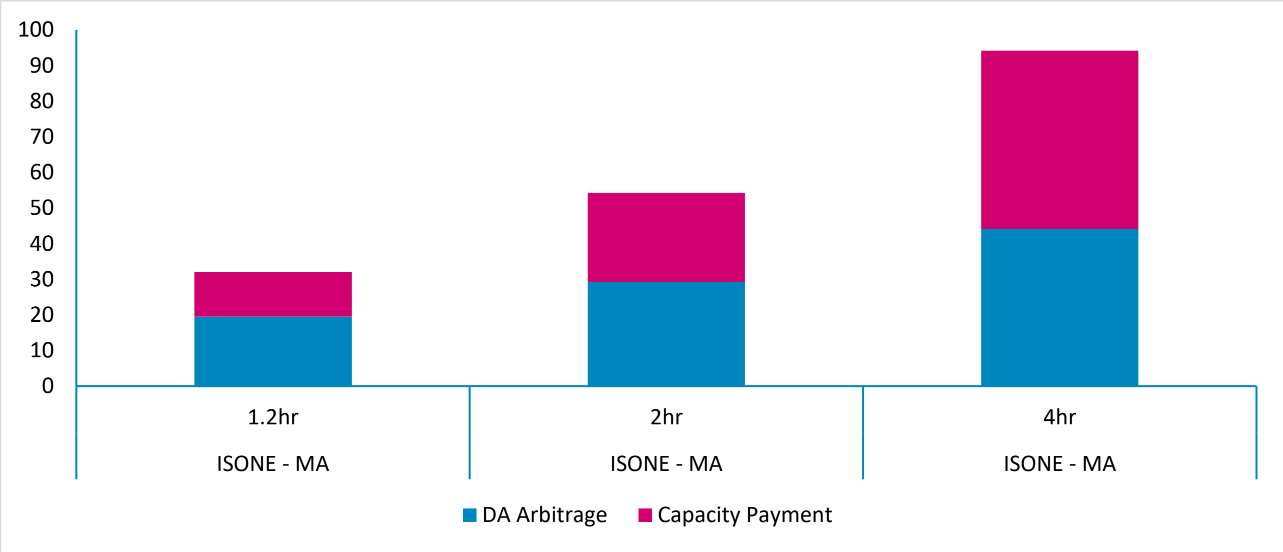
While the table above is not exhaustive, the listed revenue streams are the most common building blocks for securing financing for the development of storage assets across Massachusetts. Importantly, while federal policy and the extension of the investment tax credit (ITC) to standalone storage has been critical in driving additional investment into the DER space, this revenue stream effectively operates as a rebate on capex and is therefore excluded from this discussion. Understanding the relationship between the other revenue streams listed above and their share of value provided will allow the EDCs to design a grid service program which minimizes opportunity cost for DERs and/or adds additional value on top of the existing value stack.

For the rest of this section, the scope of the discussion is limited to revenue streams for standalone storage assets, which removes the SMART program from the list of potential revenue streams. We have made this decision because SMART participating facilities are required to forfeit the energy from their system to the EDCs. On top of that, SMART facilities receive a flat compensation rate for energy generated. Overall, these nuances remove/ease much of the operational friction that typically exists between asset behavior and distribution-level constraints.

With the focus now on standalone storage assets, the potential revenue streams are mostly limited to the Massachusetts Clean Peak Standard and various ISO-NE wholesale power products.

From a wholesale market perspective, ISO-NE sees slightly less favorable battery storage economics relative to other ISOs and RTOs. For example, according to historical data from 2021-2022, revenue for a 2-hour battery asset participating in Day-ahead energy market arbitrage and the ISO-NE capacity market amounted to $54.3kW/year, which is nearly 50% below what a similar asset would achieve in markets like CAISO and ERCOT. This differential is primarily driven by historically low-capacity market prices and limited arbitrage opportunity in the ISO-NE Day Ahead (DA) and Real-time (RT) markets. Ancillary services, such a frequency control and forward reserve, also contribute little long-term upside due to the small size and shrinking nature of these markets.

Figure 7 - Illustrative arbitrage and capacity revenues by battery duration, $/kW/yr



We have included some illustrative analysis to demonstrate the sizes of these revenue streams here. There is a detailed overview of current regulatory state, programs, and revenue streams in Appendix B.[11]

To green the state's peak energy mix and combat some of the tricky storage economics highlighted above, Massachusetts has recently enacted the Clean Peak Standard (2020), which allows storage assets to generate additional revenue by charging during periods of high renewable penetration and discharging during peak demand hours. According to Baringa analysis of historical ISO-NE prices throughout 2021-2022, a 4 MWh battery could create between $140-160/kW of additional gross margin through participation in the Clean Peak program.[12] Given the lucrative nature of this program, many standalone storage assets view the CPS credits as their primary revenue stream. In fact, according to several stakeholders, revenue streams for standalone storage ordered in terms of highest to lowest value are roughly:

1. MA Clean Peak Standard
2. ISO-NE Forward Capacity Market
3. ISO-NE Energy Market (arbitrage)
4. Ancillary Services

While ideally the service provided by the EDCs would stack cleanly on top of these existing revenue streams, if participation does conflict, a well-designed distribution-level service would aim to maximize grid benefits while limiting the opportunity cost to asset owners.

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[11] These revenue figures are meant to show revenue potential from ISO-NE but do not include revenues from the Clean Peak Standard or ancillary services.

[12] Ancillary services are not included in this analysis. Additionally, we have assumed Clean Peak Energy Certificates (CPECs) are valued at the Alternative Compliance Payment (ACP). The ACP value is the highest price that can be received for the certificates in a given year. These projections also assume 100% forecast accuracy and participation. As such, we expect the resulting revenues from these certificates to be the maximum amount that a battery would ever earn.

2.5 Scenarios that are likely to be attractive

Areas where there is moderate load growth, but high circuit upgrade costs have generally been an attractive location for these types of programs because the contracting of dispatchable DERs can "keep pace" with load growth needs. Low (or less predictable) load growth on suburban feeders has also proven to be an attractive location for DERs providing distribution grid services as it may allow for focusing traditional grid upgrades on the most critical load issues and DERs to provide option value for delaying an upgrade. In contrast, rural feeders with significant passive solar deployment, tend not to provide positive business cases when compared to traditional grid solutions because it is difficult to add enough dispatchable DER load to absorb the daytime peak solar amounts.

EDCs would need to complete more detailed load growth analysis on their specific networks to develop a view of sites that have these characteristics, and ultimately where flexibility value sits. This is considered in Section 6.

2.6 Benefit & Cost Framework Summary

The key takeaways from this section are:

- **Focus on peak load reduction for thermal constraints**: This benefit has the most expected value for the EDCs and its rate-paying customers, can be relatively easily defined and measured, and can draw on a range of case studies from other geographies.
- **The value of DER can be realized as a step change over time**: The benefit of flexibility comes from its inherent incremental nature. We can picture this as a step-change in the value of DER from peak load reduction.
- **Capacity factors**: There is not a 1:1 relationship between DER nameplate capacity or operational capability and how it is factored into planning decisions. Using capacity factors to account for risk of non-delivery of DER can be a key component of valuing a DER service. These can be designed to find the right balance between operational control / reliability and compensation / bankability of revenue streams.

3 Operational Framework

3.1 Introduction

Delivering benefits described in the previous chapter is highly dependent on a robust and well-designed operational framework to allow EDCs to have confidence in the ability of contracted flexible DERs to provide services when called upon.

3.2 Communications Networks

3.2.1 Metering & Measurements

A revenue-grade utility meter with a price tag on the order of $1,000[13] represents a relatively small additional cost to add to the construction and interconnection of a DER with nameplate capacity in excess of 500 kW. More importantly, given the scope of resources under consideration being those without co-located loads, the DER facility would require a meter to interconnect as a standard matter of the interconnection agreement. But as the DER size under consideration is lowered and resources co-located with loads with an existing net meter are involved, this conclusion will need to be re-examined.

Cost is not the only factor which should be considered to determine if utility meters are the optimal device for measurements. Other factors include accuracy, timeliness, reliability, and perhaps most important for the future, capabilities to record more complex measurement types. Devices which support IEEE 1547 have a wide range of capabilities, from reporting nameplate information to updating settings and operational modes based on instructions. Focusing on the measurement aspects in this section of the assessment, IEEE 1547 support includes the ability to report:

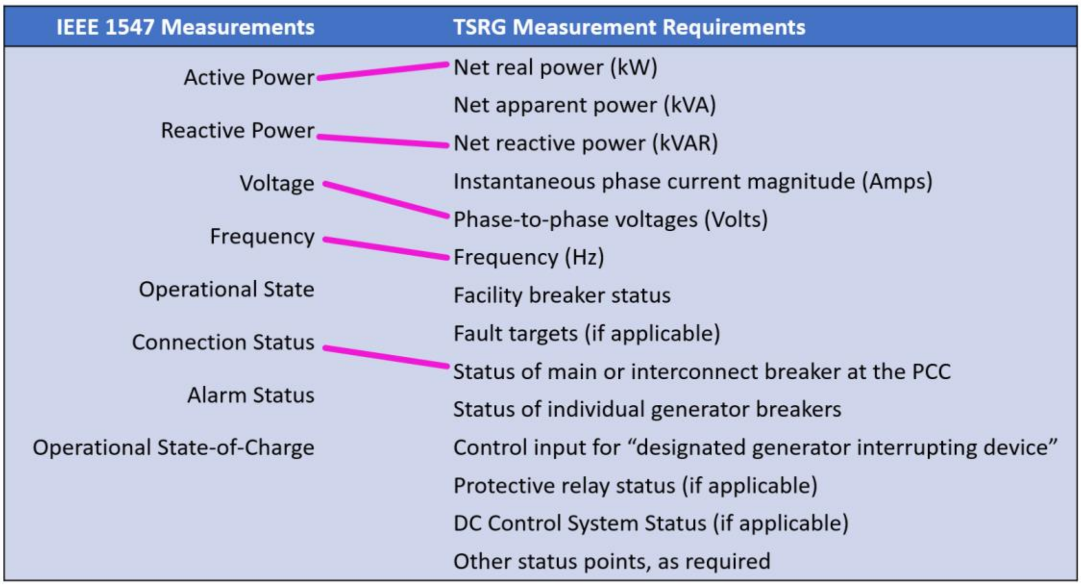
- Active Power
- Reactive Power
- Voltage
- Frequency
- Operational State
- Connection Status
- Alarm Status
- Operational State-of-Charge

Implementations vary, especially with any fields containing free-form statue or a status field, notably with DNP3, IEEE 2030.5, and SunSpec Modbus using different sets of allowable values. The Massachusetts Technical Standards Review Group (TSRG) has defined measurement requirements[14] for DERs, and there is very good (although not complete) alignment between the native IEEE 1547 measurement functions and those requirements, as illustrated in the following mapping:

[13] https://www.manta.com/cost-electric-meter-installation-san-diego-ca - Most of the cost is in the installation, not the meter.

[14] Massachusetts Technical Standards Review Group: Common Technical Standards Manual, 2022-12-22, Section 6.2: Data Acquisition and Control

Figure 8 - IEEE 1547 Measurement Functions



Like demand response program variations, DER services can either be **Stand-By Services** with **Allocation Payments** or **Active Services** with **Delivery Payments**. Active services are generally of higher monetary value, so typically a stand-by service that is activated has both an allocation payment and a delivery payment. As an example, if a reserve-style service is created, an allocation payment is given for any resource which clears and in the presumably rare case where reserve calls are necessary, the resource will be compensated both for the allocation payment as well as for the energy delivered during the reserve call.

Measurements are likely required for both allocation payments and delivery payments. Continuing the example of the reserve-style service delivered by a DER, the utility might wish to poll for a Connection Status = “Connected” or perhaps an Operational State = “On”. More sophisticated analyses might query that the Operational State-of-Charge be at or above the level to cover the cleared amount of the service. If dispatched, the Active Power could be integrated over the dispatch period to confirm delivery and subsequently qualifying the resource for the Delivery payment. These sorts of computations are typically beyond the capability of a standard utility.

3.2.2 Dispatches & Controls

Turning attention towards the information flow from the utility or market operator to the resource, there are many forms of information which might constitute an operational instruction. To help constrain the discussion, this analysis adopts the following definitions:

Dispatch: A Dispatch is an instruction to produce or consume **energy**. A dispatch may be delivered in advance, for example in the form of a day-ahead hourly schedule, or it can be in near real-time with setpoints delivered within the qualified notification window of the resource. Energy schedules will initially be focused on real power, but future dispatches may also include reactive power targets.

Control: A Control is an instruction to change the **operational state** of the DER, generally tied to the capabilities of one or more inverters associated with one or more DERs. Examples of control include:

- Enter Service (Connect)
- Exit Service (Disconnect)
- Enable Constant Power Factor (CPF) mode

- Enable Voltage – Reactive Power (VV) mode
- Enable Active Power – Reactive Power (WV) mode
- Enable Constant Reactive Power (CRP) mode
- Adjust Frequency Ride-Through settings
- Adjust Voltage Ride-Through settings

Embracing the IEEE 1547 standard will enable these sorts of control functions. Using IEEE 1547 for Dispatch, on the other hand, may not be as clear-cut a decision. DER owners will likely not relinquish complete control of energy flows for the DERs. DERs will want to have the ability to switch between opportunities available from the distribution operators, through the markets, or even through competitive suppliers. And switching ideally would not entail replacement of control technologies, even if it might be as simple as "re-pointing" the DER to another source.

As smaller DERs come into scope, aggregations will be necessary to collect certain revenues and having an aggregator necessarily introduces another party which must take service targets and convert them into individual DER schedules. Furthermore, when DERs are co-located with loads, local use of the DER will sometimes override service delivery to the utility or market operator, so there must be a mechanism to allow for a more flexible scheduling process.

If Massachusetts wishes to adopt a standard for communicating with DERs, there are several options, which are being explored as a part of the IEEE 1547 Working Group:

- IEC 61850-7-420
- IEC 61968/61970/62325
- IEEE 2030.5
- OpenADR

Each has advantages and disadvantages, and a thorough fit assessment should be undertaken to determine an optimal implementation path. IEEE 2030.5 is a popular approach in the United States, less so in other countries. OpenADR has the important distinction of large inertia with many manufacturers supporting the protocol; however, it is based on stand-alone data models that do not in reality interoperate with other protocols.

IEC-61850-7-420 has international support but is relatively low-level and may be difficult to integrate with future retail-style flexibility marketplaces. The three IEC standards numbered IEC 61968, IEC 61970, and IEC 62325 are collectively known as the Common Information Model (CIM). The CIM has a rich information model including the most robust mechanism to build grid representations but has experienced slow adoption in the United States compared to Europe.

3.2.2.1 Activation principles

Activating DERs is a complex problem. Not only are there many DERs, each with different characteristics and owner preferences, each located on a different part of the grid with different physical constraints, but there are also many potential consumers of DERs services, including:

1. Wholesale market/transmission operator
2. Distribution operator
3. Energy Supplier, if retail choice is chosen
4. Customer, if the DER is capable or provider local service like outage resilience

We refer to each customer type as a Category. The first step in solving this challenge is defining standard market products or services. Standard products for Category 1 (wholesale market) are already defined, and where new services are needed there is already a stakeholder-based process to evolve the market. For example, the California ISO and the Midcontinent ISO have both implemented ramping products. As the Northeast deploys more wind and solar resources, a similar product will likely evolve at ISO New England.

Category 2 (distribution operator) is the next place to develop standard products. As noted above, the UK has a good example of how to begin the process. Key to these product designs will be to focus on grid services, as Category 3 (energy supplier) will largely cover energy arbitrage opportunities through rate designs that encourage load shifting to hedge price. Finally, customer desires covered in Category 4 (customer) don't constitute standard products; rather, preferences here in general terms determine how much capacity is made available versus how much is held back.

Once standard products are defined for Categories 1 and 2, the activation methodology question can be addressed. In general, products of any type can be stacked "horizontally" in time, meaning that during one period a DER can provide one service to one buyer and a different service to a different buyer during another. Vertical stacking, which is delivering multiple services at the same time, is much more constrained and should be governed by the physics of electrical systems.

Vertical stacking can be constrained on the front-end by defining in advance which services (and which services only) can be coincidently delivered. The sort of approach would force DER operators to investigate potential revenue streams and apply to supply them according to their own strategies. Or a "hierarchy of grid needs" could be defined which could order all the products, wholesale and distribution alike, and dispatch would be followed using a top-down approach. The activation principles must be considered during the market design phase which could allow for more sophisticated approaches that consider concepts like co-optimization among products (as is done at wholesale today)

3.2.3 Market Interface

Implementing an abstraction layer would facilitate more sophisticated, market-based scheduling including price-based dispatching at the distribution level, like processes today in wholesale. Having a central market interface is also potentially an effective way to support the value-stacking of different grid services.

Some of the most advanced plans for a unified market interface for flexibility services has been performed by the United Kingdom's regulator, Ofgem. In their report, "Flexibility Platforms in Electricity Market,"[15] Ofgem documents six core tasks for a flexibility platform:

1. Coordination
2. Flexibility Procurement
3. Dispatch & Control
4. Platform Transaction Settlement
5. Platform Market Services
6. Analytics & Feedback

Tasks 1, 2, and 3 are flagged as the most critical tasks which must be supported with tasks 4, 5, and 6, considered value-added services. Following Ofgem guidance, Massachusetts might consider a central market interface for DERs which would have a similar minimum scope of (1) Coordinating resources, service opportunities, and information flows, (2) Facilitating the matching of buyers and sellers for grid those services, and (3) Providing a central "hub" for controls and responses during operations.

[15] https://www.ofgem.gov.uk/sites/default/files/docs/2019/09/ofgem_fi_flexibility_platforms_in_electricity_markets.pdf

The concepts covered in the previous sections (Metering & Measurements and Dispatches & Controls) could be established on a utility-by-utility basis, or could align existing systems (e.g., DERMS and ADMS). There are also benefits to considering merging separate processes into a system which could coordinate them efficiently. Here too, Ofgem provides some guidance on the forms that such a system could take, with four levels of maturity, namely:

1. **Uncoordinated.** Essentially the business-as-usual case with each utility operating its own systems and implementing uncoordinated processes, albeit with State regulators providing guidance toward similar implementations.
2. **Coordinated.** This model introduces standards to be adopted across each platform with governance negotiated among the utilities to agree upon practices, much like the TSRG has done today with IEEE 1547 adoption guidelines with perhaps a bit more uniformity enforced.
3. **Super-Platform.** This model introduces a single platform, taking the burden away from each utility to implement and operate an independent exchange and allowing participants to interact with a single entity which has a single set of governance procedures. The challenge here is to either create a new entity in Massachusetts to perform this role (or perhaps expand an existing State agency to cover the role), or to subcontract out the job to an independent entity or one of the incumbent utilities.
4. **Single Market.** The Super-Platform still allows for each utility to develop its own grid service definitions and mechanisms to set prices for those services. With the Single Market approach, all grid service procurers compete for DERs in a common market formalism with uniform procurement and pricing policies.

Many goals can be achieved using the business-as-usual model, "Uncoordinated" in Ofgem's terminology above. However, envisioning a more advanced future state of the Massachusetts DER marketplace may make near-term decisions clearer. This kind of "right to left" thinking often helps to commit to more impactful decisions earlier. The need for evolutionary thinking will likely become increasingly obvious over time, especially with higher volumes of participants, smaller sizes of DERs, and more market-based, asynchronous dispatches. Considering communications standards and equipment is a good test of this type of evolving thinking. Today, for reliable dispatch and performance standards, many power market functions require dedicated, high-cost Remote Terminal Units (RTUs) connected to grid operators on high-speed fiber optic cable. In the future, with many more smaller resources, simpler, lower cost communications and dispatch standards may become more appropriate.

3.3 Aggregation

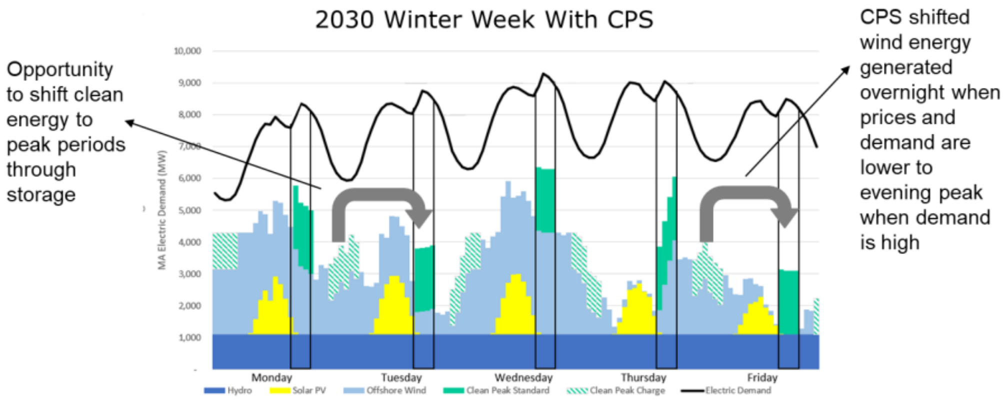
As discussed in Section 2.3.1 on EDC Costs section, dealing with aggregations of small DERs will need to be addressed. However, given the scope of this assessment targeting DERs of at least 500 kW, it is unlikely that aggregation issues need be addressed at this time.

3.4 Optimization and Value Stacking

3.4.1 Summary of Revenue Stacking

Within the current state of play, several of the existing revenue streams for battery storage assets are stackable by nature. Take the relationship between energy market arbitrage and the MA Clean Peak Standard (CPS) for instance. As discussed in the detailed breakdown within Appendix B, the goal of the CPS is to shift clean energy to serve on-peak load. Inherently, the same periods of high renewable penetration that are targeted by the CPS are already the typical charging windows for energy arbitrage. In other words, by providing an additional revenue stream, the CPS further entrenches the natural behavior of storage assets participating in arbitrage. This phenomenon is evident in material provided by DOER on the CPS:

Figure 9 - Illustrative view of winter week windows



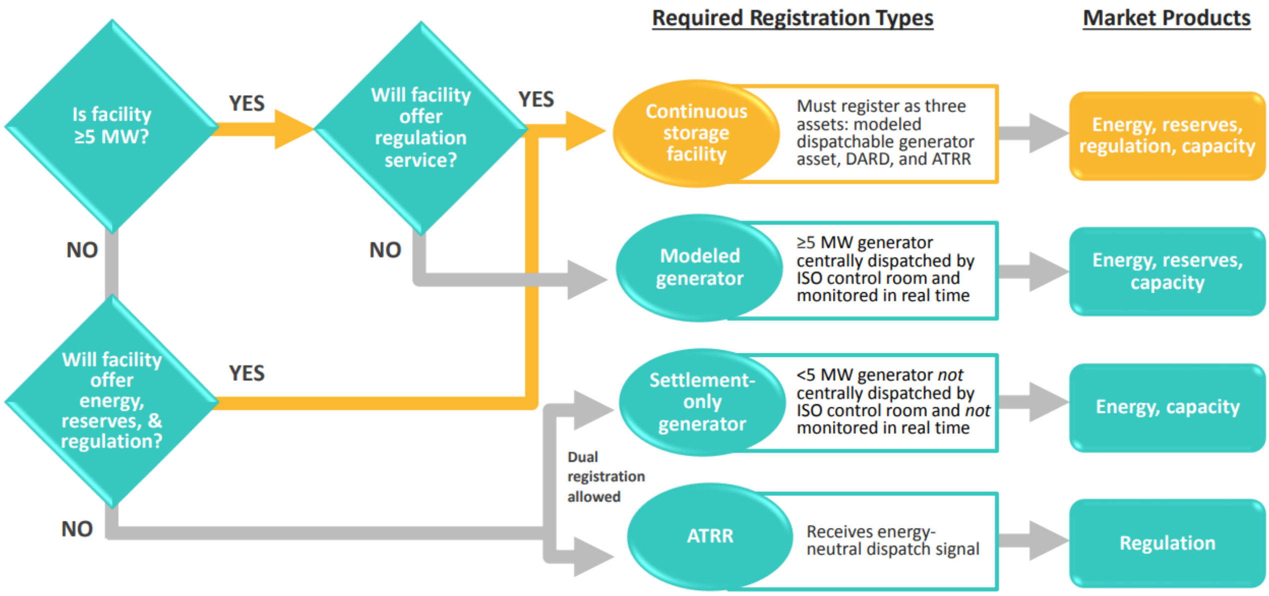
One potential area of conflict between these revenue streams, particularly as ISO-NE moves toward a greater share of variable renewable energy sources, is when the wholesale price of electricity does not align with Clean Peak hours. In considering this conflict, two primary examples come to mind, the first of which being the fact that storage behavior compliant with the existing CPS rules will inherently change the shape of load over time. In other words, as more storage shifts clean electricity into the peak, the ISO-NE peaks are likely to shift later into the day. With that said, it is reasonable to assume that the program will be flexible enough to alter the approved hours for charging and discharging as these profiles change. The second scenario is one in which unforeseen grid conditions (such as a plant trip) cause a real-time price spike outside of approved discharging hours, which would force a decision between chasing real-time (RT) price volatility and maximizing Clean Peak revenue.

Capacity revenues, given their low operational lift, are quite easily stacked with additional revenue streams. As discussed in the appendix, capacity payments are typically paid on availability unless an emergency event requires the capacity to be dispatched, though the rare nature of emergency events allows this revenue stream to be stacked with other services. With that said, it is critical to note that non-performance within an emergency capacity event could result in a penalty in excess of potential revenues through the program. From a dispatch perspective, this means that an emergency capacity signal from ISO-NE would likely result in an immediate reprioritization of revenue streams within the optimization engine, with capacity performance likely trumping all other products. From a stacking perspective, this could be problematic if the asset in question had expended its capacity into other revenue streams prior to being called for capacity, ultimately resulting in an inadequate performance in the capacity market.

Ancillary services are more complex from a stacking and optimization perspective. Given their inherent ability to quickly ramp up and down, lithium-ion battery storage assets are well positioned to provide ancillary services, with a particular advantage in providing frequency regulation. A typical strategy for a storage asset would be to offer frequency regulation capacity into all other hours that were not being optimized for other value streams. This allows to asset to constantly generate revenue for frequency capacity, even when the service is not being called into dispatch. Where this can clash with other revenue streams is when frequency regulation is required and the asset receives a frequency price signal that is not aligned with products like the Clean Peak Standard, energy arbitrage, or even the capacity market. Take, for instance, the case where regulation down services are required during the monthly peak – if the asset complies with the regulation down signal, it will likely miss out on the 25x clean peak multiplier as well as any arbitrage opportunity, thus foregoing revenue for these services.

Another potential area of conflict on this topic relates to how energy storage assets choose to register with ISO-NE. Currently, there are several registration types available for energy storage assets participating in the ISO-NE markets; these registration types differ based on the size, technical specifications, interconnection voltage, and desired market access and function for the asset in question.

Figure 10 - Flowchart of Energy Storage Registration Options[16]



As displayed in the flowchart above, storage assets registered as Continuous Storage Facilities (CSF) can participate in the full suite of ISO-NE market products in exchange for exceeding a certain size (5 MW) and/or registering their asset's capabilities under three separate registrations for generation (Modelled Generator), Dispatchable Asset-Related Demand (DARD), and balancing (as an alternative technology regulation service or ATRR). The CSF classification was uniquely created for bi-directional assets like battery storage and allows for fairly unrestricted stacking of ISO-NE market products. On the other hand, 'Modelled Generators' are not considered to be bi-directional, and therefore forego participation in the regulation market while also opting into central dispatch from the ISO, both of which present potential conflicts and limitations for state and wholesale revenue streams. Critically, the modelled generator registration type is typically limited to large assets (>5 MW) and is therefore out of the scope of this discussion. For smaller assets looking to maximize revenue streams, these assets can choose between CSF registration or dual registration as a 'settlement only generator' and an ATRR, the combination of which allows for fairly straightforward stacking of state and wholesale revenue streams.

3.4.1.1 Hierarchy of Grid Needs

The challenge with vertical revenue stacking (i.e., multiple value services delivered in the same hour) comes when one or more of those revenue streams involve a mandatory dispatch to serve grid reliability needs. Generally, most DER markets that include distribution services products recognize the uniqueness of distribution constraints and the likelihood that fewer resources can respond to a distribution constraint than those that can respond to a transmission constraint or simply participate in energy arbitrage.

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[16] ISO-NE, *Continuous Storage Facility Participation*

A basic hierarchy of grid needs to prioritize DER dispatch might look something like this:

- Highest priority – primary distribution[17] thermal or voltage constraint
- Secondary distribution thermal or voltage constraint
- Wholesale market capacity dispatch
- Wholesale market ancillary service dispatch (could be above capacity if for a locally required service in a load pocket)
- Wholesale market energy arbitrage

Further granularity could be added to the hierarchy by considering the use of DERs under specialized grid loading situations or configurations. For example, cold load restoration scenarios might have the highest priority as they could be used to restore de-energized circuits faster. Similarly, for high priority planned work on the network, DERs could be used to selectively unload a feeder to allow load transfer to complete system work.

3.4.1.2 Conflicts & Overlaps

To develop a cost-effective market for DERs to provide grid services, we must both 1) ensure that DER are available to provide critical grid services and can be relied on with confidence, and 2) allow for the maximum revenues to be stacked when grid services are not required thereby reducing the cost of providing grid services. Understanding the realistic conflicts and overlaps between grid services is critical to try to design a mechanism that is reliable for EDCs and cost competitive for DER providers. The tricky part seems to be identifying when and where a DER may be needed and to allow for enough time (typically within day-ahead) to notify a DER that their resource may be needed for grid services. For high priority critical services such as black start/cold-load pickup[18] or load transfer, resources might need to be reserved to just participate in distribution markets.

The economics of energy markets will generally, but not always, align DER dispatch interests at wholesale and distribution level so long as the wholesale price signal is visible at distribution. At times of high load and high market prices, dispatchable DER will want to generate and send power (e.g., battery discharging) onto the distribution grid – thereby unloading heavily loaded distribution facilities. At times of low load and low market prices, dispatchable DER will want to absorb power (e.g., battery charging) thereby loading more lightly loaded, or reverse flow, distribution facilities. There will be more cases in the future where local systems peak at different times from wholesale market, for example for specific sections of network with different pace of heat and transportation electrification.

Similarly, capacity market requirements will generally track the dynamics of energy markets with wholesale needs generally aligning with distribution needs. But capacity markets pay forward compensation for reservation. Care must be taken to design the interface between wholesale capacity markets, especially under FERC Order 2222 and distribution level markets.

The largest area for potential conflict between wholesale market and distribution level market needs is in the regulation market. Regulation is both an up and down service. There are times, even at high load and high prices where resources providing regulation are asked to “reg down” or reduce generation (thereby increasing distribution feeder loading), or alternatively “reg up” by increasing generation (thereby reducing

[17] Primary distribution circuits, also known as express feeders or distribution main feeders, carry medium-range voltage to additional distribution transformers located in closer proximity to load areas. Secondary circuits are where residential and commercial customers receive power off a service drop through a metering socket.

[18] Cold load pickup is an overcurrent condition that takes place when a distribution circuit is re-energized following an extended outage. It is referred to as cold load because the power supply has been unavailable for a period so that the load has reached a “cold” state before being re-energized therefore requiring more power at re-energization than when the outage occurred.

distribution feeder loading) at low load. These have a high degree of potential to overlap negatively with critically required distribution services dispatch especially on days and times with high loads, or reverse flows, that approach circuit limits. A simple approach to resolving this overlap could be to require DER to opt-out of regulation markets on a day ahead basis when notified of the potential for a distribution services dispatch. Alternatively, there could be a "buy back" service for DERs, where they could be exempted from performance penalties for not providing regulation services when they have been called on for distribution services.

3.4.2 Notice provisions

When designing the lead time to dispatch a DER, it is important to understand that it is not the "maximum time the customer will accept" but rather the "minimum time required by the grid for the service." Services that are needed to support grid maintenance can be procured weeks in advance. Weather-based, peak-load reduction services, likely days in advance. Certain emergency response products may be called in near real time. As the values of these services are established, customers (or aggregators on behalf of the customers) will install the control systems to meet the needed specification to take advantage of the potential revenue. Again, we return to the needs for a defined set of products which, based on grid location, time, weather, load growth, or/or emergency conditions will have different values.

3.5 Operational Framework Summary

The key insights from this section are:

- **Understand operational limits for accessing value of flexibility**: There are many ways of getting flexibility from assets that depend on their characteristics – whether they are dispatchable or not, whether the flexibility is pre-scheduled or dynamic, the degree of control (e.g., central control some vs. localized). Each of these operational decisions will have technical and financial implications. If the desire is to build gradually and learn as we go, the approach could be to target the low hanging fruit to access the benefit and understand the trade-offs.
- **Hierarchy of grid needs and conflicts**: Constraints at the distribution level are unique, and there are fewer resources that can respond to a distribution constraint. Any dispatch hierarchy across the grid should consider this and consider the use of DERs under specialized grid loading situations or configurations.
- **Activation principles are yet to be defined**: Definition of activation principles/products at distribution level is required to define how DER would be activated in line with grid hierarchy and co-participation principles.

4 Compensation Structure Framework

4.1 Components of compensation frameworks

Contracting and compensation structures for DER to provide distribution grid services must balance economic compensation to DER owners with reliable provision of vital services to distribution network operators to enhance grid reliability at an attractive price to consumers. Starting from a common understanding of compensation, we can then work on the various options available within each component and determine which is most relevant based on the network need and service under consideration. There are various implications from a given choice selection but as mentioned previously have the potential for cascading effects. The key factors that are drivers of a program setup, such as for flexibility services, within the context of compensation framework are as follows: price, volume, tenor, control, availability, allocation, stacking, payment basis, and performance.

These components are necessary to be considered as a part of program setup and design and are defined below in Table 7.

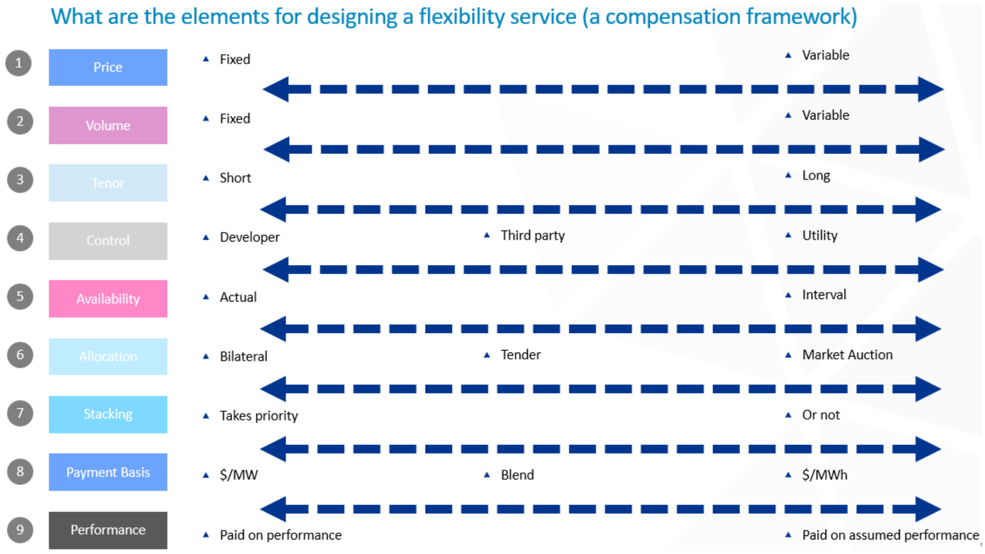
Table 7 - Components of compensation frameworks

Component	Description
Price	Value ($) on the allotment of a service on a fixed basis or established by clearing participants
Volume	Declare in advance the allotted size of service or take in bids from participants in an open format
Tenor	The length of contract term will be driven by the nature of the product or planning cycle needs
Control	A spectrum of control: natural behavior, a middle ground (contractual) or remote (full control)
Availability	Agreed period/time in which service offering 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	On what basis is compensation paid out (demand, energy, or a blend)
Performance	How successful delivery of service is evaluated and determined

Historically, policy makers and electricity regulators have made choices that resulted in the proliferation of "boutique" technology-specific rates (e.g., for solar, electric vehicles, and storage). Yet the composition and structure of rates should be technology agnostic, with price signals serving to engender/influence the actions of asset owners. There are several contentious elements on compensation, but the choice selections of each have cascading effects. Industry developers have concerns around a payment structure that leads to rates changing frequently, whereas the EDCs primary concerns are with gaming and the risk of non-performance, resulting in the lights going out.

A project developer's preference is for stable and predictable pricing as variable or unpredictable revenue streams will increase the cost of capital for projects. However, the very aim of incentivizing load shaping requires some level of dynamic pricing. The reasons for this include needing to factor in locational and marginal costs on the distribution system, as well as account for the avoided costs on the grid in terms of deferred investment spending. Thus, we are required to manage the EDC's grid system needs and balance this against the expectations of the asset owners we hope to participate as the nascent flexibility service providers. The most challenging element of the flexibility services is defining the operating metrics and performance standards that shall be applied to judge whether DER should receive compensation and avoid penalties for non-performance.

Figure 11 - Elements of compensation framework design



The **price** and **volume** can be set independently wherein the value and allotment size of service one wishes to procure is determined administratively or alternatively they can be equilibrated through some form of market clearing process via bilateral negotiation, a tender process, or a market clearing approach. The pathways can vary from one setting prices administratively versus achieving a market clearing. The question becomes what's the tipping point of one to the other; as well as if the market aggregators or DER participants have appetite for participation? The decision to set a fixed price assumes the value that we have decided on is reflective and competitive enough of an offering versus the other prevailing revenue streams that a given DER can participate. The risk in this strategy is that pricing is insufficient, and one ends up with a failure to accrue enough participation/volume of bids. Conversely, there is a risk that not enough market actors are available for meeting the grid constraint with these future services.

Tenor, control, and availability are components for structuring, and are influenced by the nature of the specific network constraint/problem that we are aiming to solve, and the planning stages of the grid/network operator. The length of the contract term (tenor) can vary from long term to week-ahead, day-ahead or even an intraday basis. As for control, this relates to the operation of the energy resource with a spectrum ranging from natural behavior, a middle ground (contractual) or remote (full control by the distribution company). The DER's availability refers to the period of time in which the asset will provide the contracted service offering. The market design needs to be established in relation to the construct of how things are developing in the service territory/area of the distribution company. The choices in each will influence the framing of the payment mechanism and can be reflected in an arming/reservation or availability (MW) and utilization (MWh) payment.

Among other considerations is the **allocation** process for selecting the assets which will provide the flexibility services. Upon examination of the pros and cons within the asset selection, one weighs the tradeoffs in cost, complexity, and depth of participants. While the difference between a bilateral contract (a 1:1 agreement) and a market clearing offer (determined via structured markets) are noticeably self-evident. A tender process has a bit of nuance: it can be viewed as an aggregation of offerings coming in and then a sorting or ranking selection of best pricing offers relative to a given cut off point. Baringa has seen these tender processes evolve more in sub-transmission constraints, where you might need a range of different DER and competitive supplier options. It is not fully a bid offer or dispatch approach; when referencing the UK's Electricity Networks Association common evaluation methodology for DER to provide system services, the grid operators establish a price to beat which is the networks approach to remedying a constraint. Within the established tender process across the different use cases for augmenting network capacity this price to beat serves as the ceiling price. The current direction of travel within the tender processes Baringa has observed is that as distribution businesses get more confident in their ability to have DERs perform, given the right economic price signals, that the tender processes are shortening in terms of the both the duration of the contract as well as the lead up to that contract and thus providing more optionality to the distribution company.

The **stacking** element refers to a DER's priority level and the optionality for contracting/operating within multiple revenue streams, whether those services are extant (wholesale energy trading & ancillary services) to those of the flexibility service on offer or vis a vis another flexibility service product the DER is contracted to perform. The asset owners view the alternative revenue streams as an opportunity cost i.e., potentially foregone revenue. The ability to stack services may be without precondition or issues; with the caveat of one or more pre-conditions, or the service is entirely restricted from be available to transform the flexibility markets and support the development thereof. The technical capabilities of a DER will determine whether the asset is suitable to deliver a particular flexibility service, e.g., speed of response or ability to sustain a set level of response.

Another key component, the **payment basis**, is the structure upon which compensation is paid out: whether this is a $/MW, $MWh, or a blend. The choice selection around the tenor, control, and availability will drive this process. In our framing from above, the final term is evaluation of the flexibility service providers **performance**. What is the methodology, and how do we recognize success or failure of the DER to deliver on the terms of their flexibility contract? Is the entire payment forfeited or are the DERs payments reduced pro-rata to within a set a band? Other questions include the extent of penalty (is it the value of the contract or is it punitive)?

4.2 Insights from case studies abroad

Baringa's review of programs around the world references several markets and use cases: from other states in the US (CA and NY) as well as internationally within the UK, Netherlands, Germany, and Australia. The detail on our review of case studies sits in Appendix A, with some summarised comments on relevance to compensation mechanisms captured below.

The most recent activity on the domestic front arises out of a proposed project in New York, wherein National Grid plans to roll out a flexibility pilot within its upstate territories; this was announced December 2022. Piclo,[19] a global marketplace provider began working with National Grid to deliver an independent marketplace that will engender participation for all types of existing or planned DERs capable of providing flexibility services. Initially the proof-of-concept pilot will run for 12 months with the first flexibility competitions set for early 2023; the roll out phase covers the area of New York State, with emphasis on National Grid's upstate New York region.

[19] https://picloflex.com/

Several years prior in California, the preferred resources pilot program, explored means of alleviating issues on the grid caused by the closure of the San Onofre nuclear facilities within Southern California Edison "SCE" service territory. The EDC sought targeted resources meant for specific localized power needs to address grid constraints, requiring SCE to establish a method for measuring DER's impacts on load.

For some of the international examples, Piclo was the market platforms in use by UK Power Network and Scottish Southern; another major platform employed by the UK, Germany, and Norway has been Nodes; in the Netherlands there is GOPACS. Baringa has witnessed flexibility markets are coming into fruition. GOPACS isn't a market per se, rather it is a communication medium that acts as a layer between various parties on the Netherlands overall network and it allows for them to communicate with each other.

Below are insights from the flexibility services used in Great Britain and the Australian Distribution Network Operator, Ausgrid.

4.2.1 Overview of Energy Networks Association case study

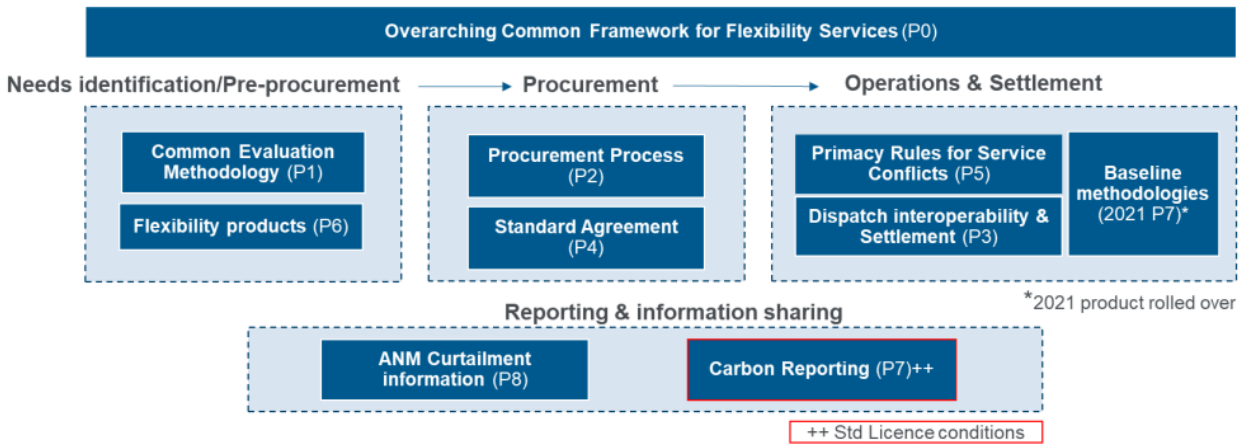
Starting in 2021, Baringa Partners has continued to work with the GB Energy Networks Association (ENA) to develop the Common Evaluation Methodology (CEM) tool[20], in collaboration with all the Distribution Network Operators (DNOs) in the UK. The tool introduced a standardized and transparent methodology for distribution network operators to utilize when evaluating and choosing solutions to address network constraints. The purpose of the tool is to provide greater visibility of the decision-making methodology and give confidence to flexibility providers, in turn stimulating flexibility volumes and competition in the market, ultimately reducing costs for network customers. The tool assesses different potential options and ensures that distribution network operators are evaluating flexible options versus traditional network reinforcement solutions consistently and transparently. The tool has been live since December 2021 and continues to evolve as it used in business-as-usual by the DNOs.

The ENA also has a parallel workstream called the Open Networks Flexibility program[21], which consists of nine workstreams across the flexibility life cycle to further enable more standardization and coordination across flexibility markets. This includes standardization of processes around needs identification, procurement, operations & settlement, and reporting.

[20] https://www.energynetworks.org/industry-hub/resource-library/on22-ws1a-p1-statement-for-common-evaluation-methodology-for-network-investment-decisions-(14-jan-2022).pdf

[21] https://www.energynetworks.org/creating-tomorrows-networks/open-networks/flexibility-services

Figure 12 - ENA Open Networks Flexibility Product Areas



As the markets for distribution-level flexibility have evolved over the past few years, there are some key findings that are relevant to the Massachusetts market.

Commercial structures for flexibility products are standardized, which we expand on in Section 4.2.3, and largely take the form of an up-front contract for a capacity reservation which is structured of availability payments and pre-defined utilization costs (or energy costs that are indexed to the wholesale market as a proxy). The requirements for flexibility are shared in advance on a market platform that is utilized by all DNOs, Piclo, and the length of the contract is also captured. Most of the contracts are in the short to medium term, ranging from 1-5 years now, given the nascency of the markets and associated uncertainty. The final service provision periods and prices are finalized as a part of the contract stage and incorporated into commercial agreements. As these products and structures were developed in collaboration with market participants, they reflect the need for there to meet the needs of both the DNO (reliability of service provision) and the DER (up front contracted revenue for a short-medium time frame). These procurement models and commercial arrangements continue to evolve over time as the market develops further and learnings are drawn.

4.2.2 Australia Case Study | Ausgrid

This case study focuses on the integration of grid-scale batteries into Australian distribution networks as a flexible form of DER. Many Australian EDCs are investigating different business models for the integration and use of grid-scale batteries, and these business models are at various stages from concept stage to implementation and operational end use. Varying business models result in differences between the benefits/value streams available, control, compensation structure, availability, performance, and route to cost recovery. Australian EDCs are exploring a range of different business models to facilitate value streams from the flexible use of DER grid-scale batteries. Potential business model range:

- from where the DER grid-scale battery is fully owned and controlled by the EDC providing regulated network support services
- to where the distribution network purely hosts the grid-scale battery which is fully owned and operated by a third-party market participant providing unregulated market services.

Between these two bookends, a spectrum of alternative business models exists, as set out in Table 8 below.

Table 8 - DER grid-scale battery business models explored by Australian EDCs

Model	Ownership	Control	Value streams	Costs and/or payments to EDC	Cost recovery of asset*
1	Owned by EDC	Fully controlled by EDC	Network support services	Capex cost to EDC plus operating costs	Asset sits on regulated asset base (RAB) of EDC and recovered via network tariffs
2	Owned by EDC with portion of capacity leased to unrelated third-party market participant	Agreement between EDC and third party stipulates capacity, times, conditions that asset is available to third party	Network support services Market and ancillary services	Capex cost to EDC plus operating costs Lease payment to EDC from third party	Portion of asset used to provide regulated network services sits on RAB of EDC and recovered via network tariffs Other portion recovered via lease payments from third party
3	Owned by related party of EDC with network support services provided to EDC via lease agreement	Agreement between EDC and related party stipulates the capacity, times, conditions that asset is available to EDC	Network support services Market and ancillary services	Lease payment from EDC to related party Network tariff charged to related party from EDC for grid access	Portion of asset used to provide regulated network services recovered via lease payments charged to EDC (which are ultimately recovered via network tariffs) Other portion recovered via revenue from market and ancillary services
4	Owned by unrelated third-party market participant with network support services provided to EDC via lease agreement	Agreement between EDC and unrelated party stipulates the capacity, times, conditions that asset is available to EDC	Network support services Market and ancillary services	Lease payment from EDC to unrelated party Network tariff charged to unrelated party by EDC for grid access	Portion of asset used to provide regulated network services recovered via lease payments charged to EDC (which are ultimately recovered via network tariffs) Other portion recovered via revenue from market and ancillary services
5	Owned by unrelated third-party market participant (with no network support services provided to EDC)	Controlled by unrelated party (subject to any restrictions in network connection agreement)	Market and ancillary services	Network tariff charged to unrelated party from EDC for grid access	Recovered via revenue from market and ancillary services

*Government grant funding is also available. For example, the Australian Government is funding 400 community batteries across Australia through a competitive grants process run by the Australian Renewable Energy Agency (ARENA)

An example of a DER grid-scale battery business model is Ausgrid's community battery trial, which aligns with model 2 above where the battery is owned by Ausgrid. Ausgrid has also proposed an innovative new network tariff for grid access for grid-scale batteries owned by related or unrelated third parties (i.e., this would apply under business model 3, 4 or 5).

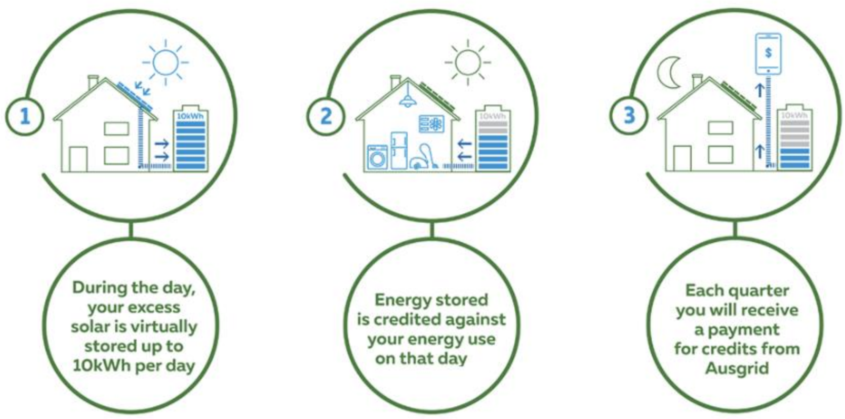
Ausgrid has installed three 'front of the meter' community batteries on its network in three different suburbs. The community battery trial commenced in 2021 and goes for two years until 2023. From a customer's perspective, Ausgrid promotes the community batteries as a 'storage as a service' solution which is an alternative to the customer installing their own behind-the-meter battery. Given the virtual nature of the service, customers who cannot afford the upfront cost of a home battery or would otherwise have challenges installing a home battery (e.g., renters) can instead use Ausgrid's community batteries. From the distribution network's perspective, they can use these batteries to provide network support services and potentially also participate in wholesale or ancillary markets (subject to ringfencing constraints[22]). Community batteries could offer a flexible alternative to traditional poles and wires investment and can reduce peak demand helping distributors like Ausgrid place downward pressure on energy prices.

A key issue encountered by Ausgrid was how to identify energy flows to and from the customer and the community battery for wholesale market settlement and network tariff calculation purposes. Under standard market practices:

- All customer imports are charged retail (including network) tariffs for each kWh imported
- All customer exports receive a feed-in-tariff for each kWh exported

Ausgrid's solution was to trial an off-market approach through a "rule book". Under the rule book, customers can store up to 10 kWh per day of excess solar PV exported to the grid in the community battery. Any customer imports are assumed to first be taken from their stored energy, and when this is exhausted, any further imports come from the market. Every quarter Ausgrid will deposit community battery credits into participating customers' nominated bank account. A separate smart measurement device is installed near the customer's solar inverter or electrical switchboard to measure energy flowing to and from the customer's house. Customers have access to a mobile app and an online portal that shows them real-time summary information of how much solar energy they are exporting to the grid, and how much energy they are using.[23]

Figure 13 - Ausgrid community battery trial – customer value proposition



Source: Ausgrid

Separate to the above, Ausgrid has also proposed to the regulator (the Australian Energy Regulator) for approval to introduce new network tariffs that would apply specifically to grid-scale batteries owned by third parties that connect to Ausgrid's network.

[22] Ring-fencing is an electricity network term referring to the separation of regulated and competitive business activities where a regulated entity also offers services into a competitive electricity market. There will be regulatory guidelines and constraints in place that lay out the legal requirements for separation and operation of businesses under this type of regime. See more here - https://www.powerwater.com.au/about/regulation/ring-fencing

[23] KPMG, *Sharing community batteries with customers – report summary prepared for Ausgrid*, November 2021.

Ausgrid proposes to introduce three new opt-in storage tariffs on July 1, 2025. The three tariffs differ by voltage level of connection. Each tariff has a separate tariff code and tariff structure for when storage is importing vs exporting. The three tariffs are:

- Local network support service tariff for low voltage storage,
- High voltage network storage tariff for high voltage storage, and
- Sub-transmission storage tariff.

Grid-scale storage connections have unique characteristics which Ausgrid consider warrant specific tariff arrangements. These unique characteristics include that grid-scale storage connections are:

- Highly flexible and price responsive forms of demand – this means highly cost reflective tariffs can be applied with minimal customer impacts because the load can respond to these efficient price signals.
- Connections where the investment decision is primarily driven by energy cost considerations – this supports the application of locational price signals to these tariffs. Locational price signals are efficient and supported by the regulatory framework in Australia, but not applied to other customers because of customer impact considerations and the cost of calculating and conveying locational price signals.
- Largely new forms of investment – this also means there are fewer customer impacts because Ausgrid is establishing the tariff signals before many customers have made the decision of where to connect and what their business operation looks like. It also means Ausgrid must be particularly wary of minimizing distortions to efficient price signals. Uneconomic tariff signals could result in new storage connections choosing to instead connect to the transmission network because of the manner Ausgrid collects residual network costs.

Ausgrid proposes to use the variable component of the network tariffs to recover long run margin costs (LRMC) only and to recover a small portion of residual costs through the fixed charges. The tariff design will be a dynamically determined critical peak price. Symmetrical import and export charges will apply during the peak periods for both the low and high voltage versions of the tariff.[24]

4.2.3 Great Britain | UKPN Flexibility services

As outlined in Section 4.2.1, the UK has taken steps to specifically align the DNOs and standardize flexibility products. There is ongoing work to further standardize the end-to-end process. UKPN took steps to specifically define the flexibility services outlined below, the information shared with the market, and the platform utilized to run a flexibility procurement. This includes standardization of what information is included (e.g., MW and MWh requirement, length of service provision, seasonal information, location, etc.), and the payment and dispatch structure for each service.

The four flexibility products that were defined by UKPN are outlined in Table 9 below and are now utilized by all DNOs in the UK.

Table 9 - UKPN Flexibility Services

Services	Sustain	Secure	Dynamic	Restore

[24] Ausgrid, *Tariff Structure Statement Compliance Document*, January 2023.

Use Case	Pre-defined schedule	Pre-fault dispatch	Post-fault dispatch	Post-fault network restoration
DNO requirement	To manage an ongoing requirement to **reduce peak demand**	To **manage peak demand** on the network, usually weekday evenings	To support the network during fault conditions, often during maintenance work	To support the network during faults that occur as a result of equipment failure
Payment and Dispatch Structure	Typically, dispatch is **scheduled** well in advance for a fixed fee	Predominantly paid based on utilization, but with some use of availability payments. **Timing of dispatch varies** by EDC (e.g., one week ahead vs real time)	Typically **dispatched at short notice** with low availability payments and high utilization payments	Typically **dispatched at short notice** with low availability payments and high utilization payments

UKPN was a first mover in the flexibility market space and published their Flexibility Roadmap[25] in 2018. Each year they publish a procurement report[26] that summarizes the types of flexibility procured and dispatched each regulatory year.

2021/2022 was the first full year of dispatching flexibility, and UKPN reports that there is significant volume attrition between the contracting and dispatch phase.

The key challenge faced in this year is translating contracted volumes into operational contracts that are ready for dispatch on the grid. Given the locational nature of the flexibility requirements, they are relying on developer solutions that have their own risks (e.g., financing or customer recruitment). This was particularly pressing for the Sustain product, which UKPN was utilizing to manage thermal constraints at LV substations. At this point in time, there are limited volumes of customers available to provide flexibility in the smaller constraint zones, so aggregators struggled to recruit the volumes from a limited number of customers. UKPN flexibility services procurement report states this issue also arose with EV aggregators, as customer uptake of EVs may have been slower than what was forecasted by aggregators, which again provides lower flexibility volumes than expected. Promisingly, this also indicates that load growth remains moderate which would delay the onset of network constraints at this site.

The key takeaway was that delays to contracting at this stage are not critical and predicted growth in flexibility volumes will parallel EV demand growth, which will help to mitigate constraints as they arise. UKPN expects to see continued growth in both procured and dispatched volumes over time as they continue to operationalize these markets.

Critically, UKPN holds a policy of no penalties for non-delivery rather than lost revenues, which they suspect could reduce the incentive to deliver. Additionally, given the current nature of the economics for reinforcement, there may be insufficient incentive for flexibility providers to deliver against their commitments.

To address delays to delivery and reduce non-delivery risks, UKPN is taking the following actions:

- Improving contract monitoring

[25] http://futuresmart.ukpowernetworks.co.uk/wp-content/themes/ukpnfuturesmart/assets/pdf/futuresmart-flexibility-roadmap.pdf
[26] https://smartgrid.ukpowernetworks.co.uk/wp-content/uploads/2022/06/Distribution-Flexibility-Services-Procurement-Report-2022.pdf

- Reviewing over-procurement factors on tendered flexibility volumes based on contract drop-off rates
- Filtering pre-qualification requirements for to filter high risk flex projects
- Considering financial penalties for non-delivery
- Developing services and engagement strategies to capture more existing flexibility where it is already available (e.g., generation, storage, demand-side flex)
- Evolving market testing to improve insights on decisions around reinforcement where liquidity or non-delivery is more possible

The key learning that UKPN will be taking into the next year is that there is a need to balance the need for delivery against creating barriers to participate. It is a priority for this DNO to incentivize flexibility, so the challenge will be balancing the appropriate mandatory performance requirements with incentivized flexibility.

4.3 Procurement models

The grid needs will drive the product offerings that are to be purchased by the EDCs. We have seen in other jurisdictions that products must be carefully designed and may serve different purposes and timeframes (e.g., annual peak, seasonal/daily, pre-fault, post-fault, restoration). Yet there needs to be a common language and evaluation process to draw as wide a range of possible flexibility service providers to bridge the gap for participation of existing assets and optimize the deployment of new assets. This would create a stronger commercial understanding of where and how different DER can resolve grid issues.

To compare the flexibility services against traditional network reinforcement, the EDCs should not simply evaluate against their initial capital outlays. Instead, they must consider longer time horizons to ensure that they meet reliability needs and test the economic prudence of the choice selection on a net present value basis (NPV). The utilities may not need to completely defer building a network facility with a single procurement but can make reasonable assumptions on future DER deployment, for a knitting together of the offerings as previously shown in Figure 3. As such, the system forecasting and financial planning account for the minimum useful life of the assets which will provide the given service, as well as the impact on revenue requirements. The NPV of the cost of the NWA solution plus the NPV of the cost of the deferred traditional solution must be less than the NPV of the cost of the traditional solution alone. The net present value cost of the deferred traditional capital program serves as the boundary or hurdle value and may be referenced under the allocation process when determining which offerings are up for acceptance.

Equation assessing Flexibility Services versus Traditional Network Upgrade

$$\mathrm{NWA(t)_{NPV}} + \mathrm{Traditional(t+n)_{NPV}} \leq \mathrm{Traditional(t)_{NPV}}$$

As the grid undergoes decarbonization and evolves with a higher penetration of DER on the system, flexibility services would provide a more visible and transparent pricing signal for capacity and reserves to meet different distribution-level needs. This will incentivize DER to locate in the most suitable places on the distribution grid, with the EDCs including the procurement of these services into its planning processes and eventually expand them to address needs closer to real time and employ shorter procurement cycles.

4.4 EDC earnings model impacts

Separately we must focus on the impacts that may accrue to the EDC's earnings models. Yet to do so, there are a set of questions that are still being explored. How are non-wires alternatives treated by the regulators today, is there differing treatment for 3rd party owned assets versus utility owned? Is the evaluation dependent on the specific technology or asset type? Does the utility regulator treat it as deferred capital upon which it may earn a return on or is it viewed as an operating expense? These are among a few of the regulatory and process considerations that are to be decided on.

There is a bias towards an initial pilot program rather than tariff changes to start as the former provides a means of testing new policy initiatives. The program serves as a form of incubator to set out the new structures, technologies, or policies within a defined scale before it is then implemented more broadly to the service territory. The benefits include flexible arrangements, and the smaller scale limits the potential financial and operational risks inherent within the full implementation that takes place under changes to the electric distribution company's tariff. The ability to gather valuable information and understandings can steer strategy, identify pitfalls, pain points, and improve decision-making more broadly.

After the programs performance review the next step would be a change to the utility's earnings composition, involving a shift towards an earning adjustment mechanism. This performance-based methodology is meant to incentivize the electric distribution company in finding the most optimal total cost-effective solution while incorporating customer assets. A pilot will have involved collaboration with various stakeholders, ranging from industry and regulators; this engagement builds support for the future initiatives and use cases. Nevertheless, this does not guarantee a direct shift in the broader policies or regulations without additional steps. In contrast to solely investing in capital projects for the growth in the utility's asset rate base, the move to a Total Expenditure (Capital Expenditure + Operational Expenditure) "TOTEX" paradigm, which evaluates spending to achieve outcomes over the life of the asset regardless of outlay classification would require significant future changes on the regulatory front.

4.5 Compensation Framework Summary

The compensation framework impacts the economic decisions of all parties and aims to address the optimal outcome in each of the components previously illustrated in Table 7, from price to performance validation. The terms of the product offerings will drive the selection of DERs providing flexibility services; meanwhile we have seen there needs to be a standardized set of products and commercial structures. The participating DERs need the requirements for flexibility to be shared in advance and the length of the procurement contracts are initially over one to several year terms but decline in length as a more robust field develops. The electric distribution companies decide on project selection by weighing whether the NPV of the flexibility services exceeds that of the NPV of the deferral in traditional network upgrade, moreover it must also evaluate if the capital deferral is enough to offset the risk of dropping load. The primary mission of the distribution system remains reliable grid service at an optimal price.

The key insights from this section are:

- **Network needs should drive product definitions:** The products that EDCs are looking to procure need to be defined and designed with the specific network need in mind. Products must be carefully designed and may serve different purposes and timeframes.
- **Common frameworks are beneficial to all**: Standardized language, commercial structures and evaluation processes are key to draw as wide a range of possible flexibility service providers to bridge the gap for participation of existing assets and optimize the deployment of new assets.
- **Designing for co-participation and revenue stacking**: As definitions of distribution level products and services evolve, it is critical that the design allows for co-participation in existing markets.
- **Balancing reliability and revenue**: For both EDCs and external stakeholders there is a preference for long-term contracts, which provide reliability of service and revenue assurance. The primary mission of the distribution system remains reliable grid service at an optimal price.

5 Views from external stakeholders

5.1 Our approach to stakeholder engagement

Engaging with external stakeholders is a critical research element in exploring market design options. Accounting for the viewpoints of those who would be participating in a market for distribution level services is critical as we consider how these markets could develop. We asked a set of targeted questions that would inform the key elements of the market design (market operations and compensation frameworks), to understand the challenges faced today and key changes that these participants would want to see as these emerging markets evolve.

Our stakeholders included a range of players; early-stage developers, small scale developers (1-5 assets), larger scale incumbent developers (50-700+ assets), and service providers who offer route to market, dispatch and battery optimization services to developers. The portfolios of these stakeholders included a range of FTM energy storage assets including standalone PV, standalone storage, and co-located BESS systems, with aggregate asset sizes ranging from 2 MW to 500 MW. All the stakeholders that we engaged are actively involved in existing market opportunities in Massachusetts, and have varying degrees of involvement with SMART, CPS, and various services in the ISO-NE wholesale market, ancillary services, and forward capacity market.

Baringa engaged with ~25 external stakeholders, ranging from large scale incumbent players to individuals, through a combination of a written survey with targeted questions and 1:1 interviews to bring richness to survey responses and challenges. The questions that were discussed with stakeholders were designed to draw light to the challenges faced with services at the distribution level today to inform any changes that could be insightful in a design of a market solution in the future.

Through these interactions several key themes emerged, which have been summarized below. On each topic there is a summary of the stakeholder commentary, and then a view of the reflections and considerations developed from discussions with MassCEC and the EDCs.

5.2 Key input from stakeholders

5.2.1 Hosting capacity maps

All stakeholders are aware of and use hosting capacity maps but are of the view that in the current state they are of limited value given the information available. The hosting capacity maps are valuable in showing how much DER is currently connected to a feeder and a substation, as well as what DER has been granted an ISA to connect but has not yet connected.

A key challenge is that there is limited information about the size or impact of the queue to connect or ongoing group studies. There is no information about any group studies that are underway at a given site, or the amount of DER that might be queued up behind a Group or Transmission (ASO) study. The lack of this information leaves developers in the dark as to how long a study might take and why, or whether their project is being considered amongst others as a part of a whole solution. Naturally there would be expected back and forth involved as the sizes of such studies evolve with increased connection queues, but the communication of where their application sits in the process leaves developers in the dark.

In addition to the lack of information about queues, there are often discrepancies between the data on the maps and the data from other sources e.g., DOER reporting of queue statistics. Developers experienced both the lack of data available around charging capacity, and the availability of actual data from the specific feeder involved in an interconnection application, with only generic data used to represent system topology available. The lack and/or inaccuracy of this information creates difficulty for developers when they are selecting locations for standalone storage DER.

Having access to this information would provide developers with a more nuanced view of where their assets could be placed to better solve grid constraints, with lower costs to connect.

Reflections and Considerations

- The scope of some of this is covered within existing working groups (e.g., ESIRG) and this feedback is consistent with existing discussions. We are assuming these issues will be considered as a part of those existing groups.
- EDCs are aware of this issue, and there is work currently ongoing within individual EDCs to improve the information available within hosting capacity maps.
- It is helpful to get the wish list of what information developers would find insightful, as this helps to guide the EDCs on what improvements are the most valuable.

5.2.2 Challenges with interconnection

Developers understand that EDCs are the 'guardians of the network', and that reliability and safety standards need to be respected to protect the grid and end consumers. However, developers believe that there should be a willingness to implement slight changes to operating strategy in certain areas that can preserve the opportunity for market participation for these types of assets.

- **High interconnection costs:** Developers are presented with large costs in development and fees for interconnection and have limited understanding as to why the costs are what they are. The impact of high costs and timing of sharing this information can result in developers becoming wary and re-evaluating strategic plays into these types of markets.
- **Long study timelines and lack of transparency of study methodologies:** It is challenging when developers are presented with long study timelines and very long connection queues. There is a perceived lack of communication of information, updated timelines, and processes for these studies, which results in developers feeling left in the dark with outdated estimates and information. The developers interact with multiple EDCs and are faced with differences in the way that studies are conducted, given there is no standardization across EDCs for storage across the state. The lack of standardization of how these studies are completed, and/or the lack of transparency regarding study procedures makes it difficult for stakeholders to build investment cases. Developers perceive that interconnection studies are being completed based on incorrect operational assumptions, which result in higher costs for interconnection when the studies are complete.
- **Lack of interconnection standards for BESS:** At this stage, given that there are no interconnection standards for BESS, the interconnection requirements are complicated for storage assets. These are not standardized across the state, which results in a lot of back-and-forth communication to clarify input assumptions and needs, which either increases the interconnection timeline or results in incorrect information being used to complete studies.

Reflections and Considerations

The challenges with interconnection are a known issue, and the aim/scope of this work is not to address these challenges specifically. However, the clarifications and insights below are critical:

- **EDCs conduct studies based on the information input into connection applications.** Currently, EDCs are studying based on how storage assets say they want to operate and use those assumptions as inputs into their planning considerations. However, this can often be lost in translation given the back and forth between developers and EDCs and the nature of the way these studies are conducted. Some information and willingness to change how they might operate is reflected in our discussions with developers and EDCs.
- **Developers understand that EDCs are the 'guardians of the network', and that reliability and safety standards need to be respected.** However, developers believe there needs to be a willingness to implement slight changes to operating strategy in certain areas that can preserve the value of market participation for these types of assets.
- There is an **opportunity to provide clearer insights up front on connection applications**, so that developers can provide more insights as to their behavior and participation in other markets. This transparency will allow the EDC to make more informed and nuanced analysis and communicate that back to developers. A transparent and iterative process could directly address some of these challenges.
- Ultimately there is **some reform to the interconnection process** that should focus on increasing transparency of information exchange, and **understanding what additional commercial mechanisms could work to create opportunities for storage solutions to connect in locations where the grid is constrained**, which would ultimately reduce the cost to connect to end customers.

5.2.3 Key developments for future distribution-level services

In discussing what changes stakeholders would like to see to make distribution-level markets viable for storage assets, stakeholders were aligned on key themes.

- **Access to appropriate pricing structures:** Different pricing mechanisms for retail rate for energy storage at the distribution level (i.e., wholesale distribution tariff) are required to incentivize distribution-connected BESS. Current retail tariff demand periods and charges make distribution level energy storage economically infeasible and prevent the opportunity for batteries to help solve grid constraints. The wholesale distribution tariff should reflect true costs and benefits of energy storage systems to the grid.
- **Major developments needed in market/program coordination:** Some MA state program eligibility is not aligned with ISO market eligibility (e.g., MA SMART FTM projects are not eligible for ISO-NE Energy Market participation). Adding options or guidelines that make co-participation clearly allowed would enable participation across markets easier.
- **Transparency in data and decision-making processes:** More information is needed on what the products and services are that developers would be providing to EDCs, and what specifically the EDCs need from developers. This could involve standardized definitions of services and operational assumptions required to meet grid needs. Additionally, increased data transparency is critical to any modelling and interconnection application (e.g., hourly charging capacity, more flexible hourly charging schedules that enable optimal operation throughout the year, beneficiary-based cost allocation, 8760 load data)
- **Evolution in technological capability:** There is a view that there is a lack of operational technology within the EDC to manage/operate within their safety margins (i.e., DERMS solutions planned to be online in 5+ years), that result in the opportunity for closer to real-time operation or dispatch being pushed into the future by several years. Additionally, developers are of the view that the technologies used as a part of interconnection studies do not have the potential to evaluate and reduce the overall cost of interconnection. Developers are of the view that increased adoption of

alternative technologies in the design of interconnection upgrades could result in overall reduction of timelines and cost to interconnect.

Reflections and Considerations

- Access to **appropriate pricing structures** is critical to enable battery solutions to connect and help address grid constraints. This is being largely considered within existing working groups (e.g., Wholesale Distribution Tariff, ESIRG).).
- Major **developments are needed in market/program coordination**. Enabling co-participation is required, and the consideration of a hierarchy of needs or activation principles needs to be designed to enable a clear dispatch hierarchy.
- **Transparency in data and decision-making processes is critical**, and standardization of services or products would be helpful for all parties involved. Common frameworks and standardization reduce the barrier to entry.

5.2.4 Compensation frameworks

The key finding from questions about compensation frameworks is that stakeholders favored long-term certainty over merchant risk, given the appropriate caveats are baked into commercial arrangements. Stakeholders favor long-term, fixed price contracts, even if that price evolves for new contracts and/or that price is modified according to feeder/substation conditions. When it comes to market participation and coordination, it was key that there is clarity and simplicity in program structure, whilst critically allowing for straightforward participation in other markets. Contracts and/or mechanisms need to be in place to allow co-participation or revenue stacking, and this should be incorporated into the design of the service. The simpler it is to participate in a market, the more likely it is that developers will be able to address grid constraints. Stakeholders had no clear preference around the structure of payments (e.g., $/kW for service or $/kWh for performance), and state that this would largely depend on program specifics around what services are being compensated and how benefits are realized.

Reflections and Considerations

- **Stakeholders would advocate for contracted revenue schemes where possible if they existed for BESS at the distribution level**. Ultimately some version of contracted compensation mechanism is favored over a free-market local pricing mechanism. At this stage the appetite for this doesn't exist, neither do the volumes.
- **Clarity and simplicity in program structure and participation is critical at this stage**. Key roles and responsibilities and simplicity in commercial arrangements should be guiding principles. These can evolve over time with learnings from real world implementation.

5.2.5 Operational control

In discussing how markets would be physically operated and how assets would be controlled when participating in an active market, there was a clear voice that was aligned across all stakeholders.

Use of industry standards for architecture and dispatch is widespread, and all assets have the technical capability to be configured based on priorities and compliance requirements. All the stakeholders who were engaged have the capability to stack products and revenue sources based on granular forecasting and would assume that any conditions around operations and control would be baked into market designs and commercial arrangements.

Ultimately, developers and operators have the technical capability and willingness to relinquish control when needed – if the requirements and conditions for doing so are outlined up front and captured legally within contractual arrangements. Each asset will have varying compliance requirements for each layer of its revenue stack which would need to be respected and prioritised, and this would be considered and modelled before any new commercial arrangements were signed.

If complete control were to be relinquished to the EDC, the contracting party would take on all rules and regulations that are applicable to operation of the asset (e.g., interconnection agreement terms, ISO-NE tariff requirements). Advanced notice of any change to operation of the asset by a contracted party would be appreciated where possible, and warranty management and associated liability would ideally be passed to the contracting party. Additionally, after an event where control was relinquished to the EDC, there would need to be complete transparency to validate the need. There would need to be visibility of any performance requirements that would justify the optimization of operations and sharing of post-event information to have on file for commercial and payment purposes.

Ultimately, relinquishing control would be feasible under conditions set out and agreed ahead of contractual arrangements being signed. Once signed, the conditions would be honored.

Reflections and Considerations

- The technological capability for near to real-time dispatch of DER assets is standard and widespread across all developers.
- The key in the market design will be to appropriately capture how **conditions around operational control will be captured within commercial arrangements**, and honor existing compliance requirements.
- This would be considered as a **definition of grid hierarchy and dispatch or activation principles**, which would be designed as a common framework and utilized across any new set of distribution level products.

6 Recommendations

6.1 Summary of Key Findings

As outlined in the summary section of each of the core frameworks, we have developed several key findings for our overall analysis, which are summarized in Table 10 below. These findings inform our recommended next steps.

Table 10 - Summary of Key Findings

Framework Area	Key Findings
Benefit and Cost Framework	• **Focus on peak load reduction for thermal constraints:** This benefit has the most expected value for the EDCs and its customers, can be relatively easily defined and measured, and can draw on a range of case studies from other geographies. • **The value of DER can be realized as a step change over time:** The benefit of flexibility comes from its inherent incremental nature. We can picture this as a step-change in the value of DER from peak load reduction. • **Capacity factors:** There is not a one-to-one relationship between DER maximum capacity and the capacity value that factored into planning recommendations. Using capacity factors to account for risk of non-delivery of DER can be a key component of valuing a DER service. These can be designed to find the right balance between operational control/reliability and compensation/bankability of revenue streams.
Operational Framework	• **Understand operational limits for accessing value of flexibility:** There are many ways of getting flexibility from assets that depend on their characteristics – whether they are dispatchable or not, whether the flexibility is pre-scheduled or dynamic, the degree of control (e.g., central control vs. localized). Each of these operational decisions will have technical and financial implications. If the desire is to build gradually and learn as we go, the approach could be to target the larger resources with relatively simple control schemes, understanding the benefit and trade-offs. • **Hierarchy of grid needs and conflicts:** Constraints at the distribution level are localized, and thus there are fewer resources that can respond to the network need. Any dispatch hierarchy across the grid should consider this and consider the use of DERs under local grid loading situations or configurations. • **Activation principles are yet to be defined:** Definition of activation principles/products at distribution level is required to define how DER would be activated in line with grid hierarchy and co-participation principles.
Compensation Framework	• **Network needs should drive product definitions:** The products that EDCs are looking to procure need to be defined and designed with the specific network need in mind. Products like load shifting, peak load reduction, distribution congestion management, and restoration support all have different requirements for resource response and vary in need by location and/or time. • **Common frameworks are beneficial to all**: Standardized language, commercial structures and evaluation processes are key to draw as wide a range of possible

	flexibility service providers to bridge the gap for participation of existing assets and optimize the deployment of new assets. • **Designing for co-participation and revenue stacking:** As definitions of distribution level products and services evolve, it is critical that the design allows for co-participation in existing markets. Note the interdependencies with this finding and "Hierarchy of grid needs and conflicts" above. • **Balancing reliability and revenue:** For both EDCs and external stakeholders there is a preference for long-term contracts, which provide reliability of service and revenue assurance. The primary mission of the distribution system remains reliable grid service at an optimal price.

6.2 Recommendations

In forming our recommended next steps, we focus on two objectives:

1. Encouraging DER to **interconnect** at locations that are beneficial to grid stability.
2. Encouraging DER to **operate** in a manner that is beneficial to grid stability.

Whilst DER can help an EDC to address a range of network issues, the highest priority use case is the management of thermal constraints that arise when the network is at peak usage, which historically has been consumption (load) but may also be production as pockets of distributed generation appear on the grid. As such, the imperative is for the EDCs to develop, trial and implement arrangements that encourage DER to interconnect and operate in ways that alleviate, rather than exacerbate, these limits.

Before attempting to develop services, market arrangements, or interconnection reforms that give rise to this outcome, the EDCs need to first understand:

1. The value of flexibility
2. How a DER can deliver that value to the EDC, and the factors that affect this value
3. What price a DER might be willing to accept for providing a service.

These factors are critical pieces of the puzzle in determining whether a DER flexibility service is viable. The value of the benefit needs to be higher than the opportunity cost of delivering that benefit. Ideally the viability sits in the middle, where a flexibility service allows EDCs to pay DERs for the value of the service delivered. The end state is to have a full set of flexibility services that sit in that sweet spot and find the balance between value and opportunity cost. Our recommendation will be focused on developing further understanding of these pieces, and immediate next steps to get Massachusetts closer to that goal.

To design services that maximize value and minimize opportunity cost, we need to understand both pieces of the puzzle. Given that the value of flexibility is driven by grid need, we recommend that trial designs should focus on understanding and testing the components and drivers that derive this value. The objective of each trial will be to understand the various factors that contribute to this value, and will explore the knock-on opportunity costs to the DER.

We propose thinking about the value of DER flexibility to the EDC in three parts:

1. For what **specific network needs** would flexibility provide a benefit to the EDC or other interconnected customers?
2. **Assuming 100% reliability**, what would be the value associated with a DER providing that service?
3. What **Capacity Factor (CF)**[27] should be assumed for participating DER, and what factors affect this?

The purpose of any trial would be to specify one or more network needs, calculate the '100% reliability' value of addressing that need, and the appropriate CF in each case. Before considering specific trial designs, let us consider the factors that affect CF in more detail.

CF refers to the proportion of the nominal (i.e., stated) DER volume that an EDC can depend on for its purposes. We have identified three key factors that affect the CF:

1. **Level of commitment/control**: The more committed the DER is to provide an EDC service, the higher the CF that the EDC can assume. This commitment could be commercial, legal, or physical (i.e., taking the form of direct control).
2. **Diversity of providers:** It is common for EDCs to draw on a portfolio of DER to deliver a service. This has the advantage of narrowing the variance of the expected output. A single large DER may be unable to deliver on a given occasion. For many smaller DER, whilst it becomes likely that a subset will often be unavailable, it is much less likely that all will be unavailable simultaneously. This is particularly true if the DER are diverse in technology type, dispatch strategy, and location since the risk of 'common mode failures' can be reduced.
3. **Nature of need being met:** Some network needs have modest downside if they are not met, whilst others are more severe. For example, displacing diesel consumption in the management of a planned outage may be low value, but the EDC can assume a high CF as the risk of non-delivery is low. By contrast, deferring reinforcement with no fallback option is high risk, and requires a low CF to manage that risk.

[27] In the parlance of the UK Capacity Mechanism, this concept would be termed "derating factor". Essentially, it reflects the difference between the stated output of a DER and the output that the EDC can assume will be reliably available for planning purposes. Using the ISO New England capacity market, this is equivalent to the Effective Load Carrying Capability (ELCC).

There are various ways that an EDC can engage DER to provide flexibility services, each with different trade-offs associated with them. As Table 11 illustrates, these can be represented by their position along each of these CF dimensions.

Table 11 - Drivers of Capacity Factors

Drivers	Low Capacity Factor	Medium Capacity Factor	High Capacity Factor
Commitment/ control	• No DER commitment • 'Natural' asset behavior	• Targeted price signals • Contracted service with penalties	• EDC/3rd party control • ANM • DERMS
Diversity of providers	• Single, large DER	• Few, medium DER • Single technology • Geographically clustered	• Many, small DER • Range of tech • Geographically spread
Criticality of need	• Low downside • Opex-type network needs (e.g., avoiding fuel use)	• Moderate downside • Manageable mitigation (e.g., involuntary demand management) or low risk/impact outcomes	• Severe downsides • Capex-type network needs that cannot be put in place quickly

This leads us to two possible trials, each of which would address peak load thermal network constraints but would test different combinations of these CF drivers.

6.2.1 Trial Option A | ANM-enabled Curtailment

Under this approach, DER would provide peak load management to mitigate a thermal network constraint. This could be by generating during times of network import constraint or acting as load during times of export constraint. The key feature of this trial would be that the participating DER(s) would need to be controlled by the EDC, for example through use of Active Network Management (ANM).

This would give the EDC a high level of control over the DER and would therefore provide a high degree of confidence that it would operate as required. This would, in principle, allow the EDC to delay or forego network reinforcement, since the DER could be relied on to operate consistently when required.

Using our CF framework, this approach is summarized in Table 12.

Table 12 - Trial Option A | ANM-enabled curtailment

	Low Capacity Factor	Medium Capacity Factor	High Capacity Factor
Commitment/control	• No DER commitment • 'Natural' asset behavior	• Targeted price signals • Contracted service with penalties	• **EDC/3rd party control** • **ANM** • **DERMS**
Diversity of providers	• **Single, large DER**	• Few, medium DER • Single technology • Geographically clustered	• Many, small DER • Range of tech • Geographically spread
Criticality of need	• Low downside • Opex-type network needs (e.g. avoiding fuel use)	• Moderate downside • Manageable mitigation (e.g. involuntary demand management) or low risk/impact outcomes	• **Severe downsides** • **Capex-type network needs that cannot be put in place quickly**

The natural home for such a trial would be in the context of flexible interconnections or Dynamic Operating Envelopes. DER would be given the option to have an ANM-enabled interconnection, allowing them to interconnect more quickly and cheaply than would otherwise be the case.

This would allow more new interconnections than would otherwise be allowed under a conventional interconnection scheme.

> **Illustrative example:** Consider network approaching an export constraint, with headroom for ***either*** a new 1MW solar farm **or** a new 1MW battery. If the battery is ahead in the interconnection queue, it will take priority, and the solar farm will need to pay for reinforcement, go elsewhere, or simply halt development. However, the battery is highly unlikely to be exporting when solar output is high. Provided either the solar farm or battery accepts an ANM connection, both should be able to interconnect. The solar farm could accept this, knowing that curtailment is likely to be rare. Alternatively, the battery could accept ANM control as a long-term service it offers to the solar farm.

It is also feasible that this could be designed as a procured service. In lieu of conventional reinforcement (arising from organic load growth on the network, for example), the EDC could identify suitable DER candidates who would be willing to accept adhering to a Dynamic Operating Envelope. There would be upfront costs associated with installing the required ANM equipment, and the commitment by both the EDC and the DER would need to be long-term.

However, the terms of such an arrangement may be able to ensure that the EDC only paid when curtailment was required (i.e., on a utilization basis). The EDC would be responsible for tracking curtailment volumes, and ultimately determine if and when conventional reinforcement becomes appropriate in the future.

There are several challenges associated with such a scheme, which the trial would need to explore. For example:

- The opportunity cost for a participating DER could be more than simply the value of the MWh curtailed; if being under an ANM scheme precluded participation in ISO services, this could significantly increase the payment that the EDC would have to make, even if the expected volume of curtailment were low.
- The interaction of ANM systems with network constraints and ISO services would need to be studied. For example, if the ISO procured a generation turn-down service from an asset that is behind a distribution constraint, under normal circumstances this would be unproblematic, since any turn-down would be 'seen' by the ISO. However, if that asset has a nearby DER under an ANM scheme, a turn-down signal by the ISO would create headroom at the distribution constraint, which the ANM system would see as a signal to allow the DER to turn-up. From the ISO's perspective, these two actions cancel each other out, so no response is seen.

6.2.2 Trial Option B | Contracted Flexibility Services

We recommend another trial that falls as second priority, and as an optional recommendation to further push the envelope in testing the limits of operational control whilst balancing risk of non-delivery. Under this scheme, DER would be contracted to provide flexibility services to the EDC, but there would be no direct control of the DER by the EDC. The only means by which the EDC could ensure DER dispatch is through contractual or legal obligations.

We propose that to balance non-delivery risk and the criticality of need, this trial is completed on EDC circuits where the risk of testing such arrangements is lower. We recommend that EDCs select several sites where the criticality of need is lower, e.g., circuits at lower risk of overloading. This would allow the commercial arrangement and price signal to be tested in a safe environment where there is little to no risk for the EDC, and little threat of interruption to customers.

Additionally, we propose that the sites selected for this trial include sites where there are co-located load and storage options. If the resources aren't energy limited, there is no reason that these resources wouldn't be able to provide both load and outage/resilience shifting. There is an opportunity here, at a lower risk site, to create a safe environment to test variations of distribution-level outage/resilience services.

The purpose of this trial would be to examine which network needs could be addressed through such an arrangement, and what conditions would need to be in place to allow it. The range of options is summarized in Table 13.

Table 13 - Trial Option B | Contracted flexibility services

	Low Capacity Factor	Medium Capacity Factor	High Capacity Factor
Commitment/control	• No DER commitment • 'Natural' asset behavior	• Targeted price signals • Contracted service with penalties	• EDC/3rd party control • ANM • DERMS
Diversity of providers	• Single, large DER	• Few, medium DER • Single technology • Geographically clustered	• Many, small DER • Range of tech • Geographically spread
Criticality of need	• Low downside • Opex-type network needs (e.g. avoiding fuel use)	• Moderate downside • Manageable mitigation (e.g. involuntary demand management) or low risk/impact outcomes	• Severe downsides • Capex-type network needs that cannot be put in place quickly

Some questions this trial would address include:

- What contractual or legal elements can be used to improve the reliability of the DER response (e.g., penalties for under-delivery)? What implications do such terms have for recruitment of participants? Can they be stringent enough to minimize or even alleviate the risk of under-delivery?
- How does CF increase as a function of DER diversity? What number of DER is necessary to have a reasonably high CF? How does having a range of different technologies (or other asset characteristics) change this equation?
- Can a combination of contractual terms and diversity of DER ever result in a CF that is high enough to be used to address 'critical' EDC needs? For example, can it be used to defer reinforcement? If not, are there medium-criticality network needs that could be used in conjunction with this approach?

6.2.3 Concluding Comments

The goal of these trials is to explore how to put the right signals in place to drive DER to be located in places where they can provide flexible support to the distribution grid. In the current context, storage developers are driven by cheap land, lower implementation costs, and wholesale energy opportunities. The only current signal from the distribution network that developers can reference is the hosting capacity maps, which are providing insufficient signal as they are not targeted at battery storage.

In the long term, the vision is that developers build their resources where they are valuable to the grid. Through extensive discussions with EDCs and developers as a part of this project, it's clear that there are challenges that need to be addressed to get to that vision.

A critical step at this point is to build trust between all participants, and to develop shared understanding and confidence that these challenges can be overcome by taking small steps together to achieve this vision. We believe that the two trials we have recommended are steps in this direction and create opportunities for involved participant communities to come together and learn in a safe environment. The immediate recommendation would be to focus on scoping out a trial design (or set of trial designs) that could address all or part of the factors set out in the framework above. The two trial options proposed are not exclusive, and there are smaller more specific factors within these that could be tested individually in real time. To pursue any of these options, MassCEC, the EDCs, and developers all have a role to play in exploring immediate next steps to get closer to an ideal market design and collaborating to push the industry in Massachusetts forward.

Appendix A DER Value Literature Review

We reviewed several geographies and drew on global experience to develop a view of the types of value that EDCs across the world are attempting to price using commercial mechanisms. Key insights derived from this literature review are captured within each associated section of the report to focus on relevant cost/benefit, operational, and commercial learnings.

In this section, we provide an overview of the market structures evolving in four progressive and important DER markets: Great Britain, Australia, California, and New York. Each of these markets is characterized by different industry drivers and regulatory structures which have had an impact on their approach. This includes trends toward increasing DER, decarbonization goals, technology trends (e.g., uptake of EVs, modernization of the grid) and the state of change from a regulatory perspective (e.g., evolution of tariffs, direct control of grid connected technologies, and commercial arrangements).

Each of the regions studied have independent transmission operators, with local distribution operations performed by the distribution system owner. It is important to mention that for each jurisdiction, market design is a work in progress and changes in direction may occur as they continue to evolve.

A.1 Great Britain Case Study

Aggressive net-zero carbon policies and a proactive regulatory climate are driving rapid increases in DER deployment in Great Britain. Rapid electrification of heating and transport are having major impacts on the grid. In addition, despite limited solar irradiation and many dense urban networks, uptake of solar PVs and battery storage in GB is also among the fastest in the world and is having effects. Rising levels of DER on distribution networks with limited network headroom are driving stakeholders to seek wider access for DER in both wholesale and new markets.

Ownership of Great Britain's electric system is divided among several types of entity. The transmission system is owned by National Grid, who is also its operator (see below), while distribution systems are owned and operated by Distribution Network Operators (DNOs), who are not affiliated with National Grid. Electric generation and retail customer supply functions are performed by yet another class of entities.

Great Britain's market is one of the most decentralized and competitive retail energy markets in the world. The wholesale power market is largely based on bilateral trading, with the Electricity System Operator (ESO)[28], National Grid, having responsibility for the real time residual balancing of the transmission system. Electricity is primarily traded by suppliers, generators, traders and customers trading in the competitive wholesale electricity market. Trading can take place bilaterally or on exchanges, and contracts range from several years ahead to on-the-day real time commercial arrangements. Electricity can also be imported or exported through interconnectors – which currently exist between Britain and France, the Netherlands, Belgium and Ireland. The ESO has overall responsibility for balancing the electricity system and takes actions to ensure that electricity supply and demand match on a second-by-second basis. The ESO has several tools that it can use to do this, including the Balancing Mechanism (BM)[29], which allows the ESO to accept bids and offers for electricity at different locations on short notice.

[28] ESO is currently owned by National Grid however the GB government is in the process of forming a Future System Operator - https://www.ofgem.gov.uk/energy-policy-and-regulation/policy-and-regulatory-programmes/future-system-operation-fso
[29] https://www.nationalgrideso.com/balancing-services/wider-access

The retail market is largely characterized by two types of energy suppliers – larger retailers that have combined ownership and operation of large-scale generation with their long-standing energy retail businesses, and relatively smaller, nimbler digital disruptors. These disruptors typically use open-source technology and agile methodologies to create innovative and exciting propositions for customers and offer creative tariffs to take advantage of emerging markets for customers e.g., EV-specific tariffs, time-of-use tariffs. Both types of energy suppliers typically either contract directly with DER or with aggregators representing DER to procure a portion of their supplies.

Distribution Network Operators (DNOs) are adapting to rising penetrations of DER by developing independent distribution system operator (DSO) functions within their existing corporate structures to meet the evolving needs of distribution grids. The DSO transition is motivated by significant actual and forecasted increases in distribution-connected DER and load growth associated with electrification, both of which will require DNOs to take on additional system operator functions such as active network management, and real-time, data-driven interventions on the network. The regulator in Great Britain, Ofgem[30], is encouraging DNOs to invest in this transition to enable rapid uptake of distribution connected DER to meet Great Britain's ambitious decarbonization targets[31]. The current expectation is that all DNOs will identify the investments required for them to operate in a DSO role as they progress into the next regulatory price period.

As DNOs evolve their capabilities to manage their grids more actively and utilize customer owned equipment to augment, or even replace, the need for certain utility-owned devices, a potential conflict is looming. Some industry participants view that as DNOs create these DSO functions, they should be separated from the traditional utility-asset ownership and management functions of the DNO. This possible DNO/DSO split will help shape the nature, design and execution of distribution level markets and services for decades to come just as the governance and split between Transmission Operations and Electric System Operations has shaped the operation of the wholesale markets.

Much attention has also been given to the potential role of the DSO in forming and operating distribution-level markets. To explore this in detail, the Energy Networks Association[32] (ENA) launched a project in 2017 called the Future Worlds Project[33] where they explored and evaluated five "future world" options for what an integrated DER market might look like to serve needs across transmission and distribution markets while supporting existing customer and aggregation programs. The ENA reviewed the five options outlined in below.

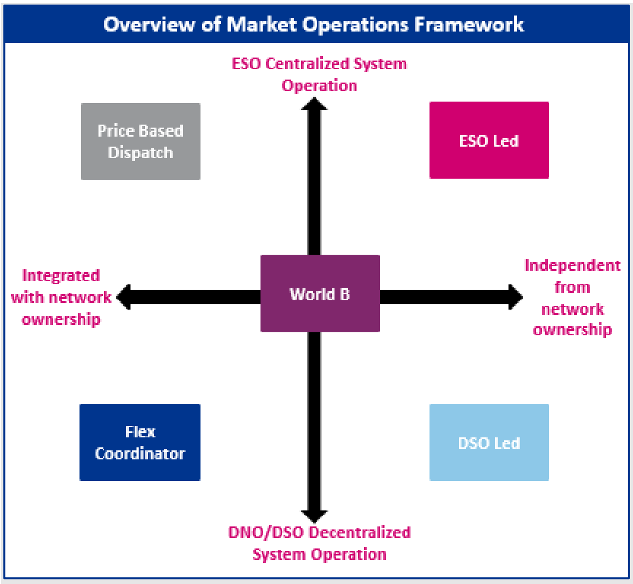
[30] https://www.ofgem.gov.uk/
[31] https://www.gov.uk/government/news/uk-sets-ambitious-new-climate-target-ahead-of-un-summit
[32] https://www.energynetworks.org/
[33] https://www.energynetworks.org/assets/images/Resource%20library/ON18-WS3-14969_ENA_FutureWorlds_AW06_INT%20(PUBLISHED).pdf

Table 14 - High Level Summary of ENA Future Worlds

Future World	Description	Pros	Cons
World A - DSO Coordinates	Sole route to through DSO. DSO provides optimized DER dispatch schedules to ESO.	• Visibility to DSO of all DER	• Constraint on DER route to market • Wholesale market relies on entirely new DSO processes
World B - Coordinated ESO/DSO	Bilateral market contracts, with the role of DSO to be defined, but with activities limited to managing residual balancing between transmission and distribution.	• Leverages existing organizations' skills and base capabilities	• Complexity of wholesale and distribution product interactions
World C - Price Driven Flex	Reform of tariff system to create a uniform pricing/access philosophy across transmission and distribution market products. This would enable increased choice in network access products available to customers and create an opportunity for dynamic price signals to become the leading market mechanism.	• Provides clear and consistent pricing models and signals to DER across transmission and distribution • May end up being a future end state for the market after functions and markets are well-established	• Requires significant regulatory change • Some ambiguity on market roles and who would be responsible for defining tariff structures
World D - ESO Coordinates	ESO provides a sole route to market for all DER. ESO dispatch scheduling based on constraint information from DNO/DSO. ESO optimizes DER across wholesale and distribution needs.	• Tight coupling to wholesale market needs • Leverages mature wholesale market functions	• Knowledge and functionality required to operate at the level of granularity of distribution networks could prove challenging for the ESO • Each DNO faces unique challenges in their network (e.g., urban versus rural, radial versus meshed). ESO led approach could result in broad brush, generic approaches to DNO unique issues, with challenges for developing distribution products that are relevant nationwide
World E - Flex Coordinator	Similar to Model B but includes the creation of an independent third party that forms a new role, Flex Coordinator, which operates between the ESO and the DSO. It serves as the route to market and is responsible for optimizing DER dispatch across multiple market needs	• Market independence from assets • Possible future path after functions and markets are well-established	• Uncertainty about who would play flex coordinator role and how it would work

Great Britain now is focusing on implementing World B, where there will be coordinated procurement and dispatch between the DSOs and the ESO, the operational details of which are still being explored.

Figure 14 - Overview of ENA Future Worlds



Under the World B model, DNOs are responsible for identifying network needs, designing products and services to meet those needs, and operating a market that procures the products and services from individual DER. DNOs will rely on a standardized set of flexibility products, developed through the ENA, which can be procured at the distribution level – Sustain, Secure, Dynamic, and Restore[34]. These products have been designed and priced to address specific grid-level needs and are actively procured by all DNOs[35]. The pricing structures for these products are designed with availability (MW) and utilization (MWh) payments, where DER providers are paid a £/MWh to both be available and to then be called on to provide services to the DNO. Pricing is established via competitive tenders for some products and is administratively determined for others. All products are designed to allow DER to participate in both the distribution market and wholesale markets, and DER providers are responsible for coordinating their own dual participation.

There has been an evolution of how these products are commercially priced and managed over time. In the early stages, two different approaches to pricing these products were used. Western Power Distribution (WPD), a DNO, employed an administratively-determined price, which was available to all DER providers able to provide services. On the other hand, UK Power Networks (UKPN) chose initially to procure services through a competitive tender. The tender was generally regarded as unsuccessful because participation was low. Feedback from market participants suggests that having no guide price at all did not provide them with enough information to build the business case for them to participate. Today, DNOs use a hybrid approach that lets market participants compete to provide services, while offering more certainty about prices and procurement quantities by providing a non-binding guide price or a range of prices to provide an indication of the value to the DNO.

DNOs are also seeking to improve products terms, as the market matures. Initially, DNOs conducted procurements a year or more in advance and sought to procure services for a multi-year term. Over time,

[34] More information on these products can be found in Table 7 below and here - https://www.energynetworks.org/assets/images/Resource%20library/ON-WS1A-P3%20Active%20Power%20Services%20-%20Final%20Implementation%20Plan-PUBLISHED.23.12.20.pdf

[35] https://www.preceden.com/timelines/523803-flexibility-in-gb-timeline

procurements have begun to focus on week-to-week products. The ENA is leading efforts to standardize and enhance the procurement processes and pricing mechanisms for these products, as they evolve[36].

In addition to having an active market for distribution-level flexibility, DNOs provide 'flexible connection' arrangements as an innovative way to use flexibility in areas of their network where constraints such as capacity, voltage or reverse power flow issues mean the cost of connection is very likely to be higher than expected due to additional reinforcement works being required. Traditionally, DER developers had only been provided with a firm interconnection option. Although such an option allows DER to access the grid, with little threat of being curtailed, it requires DER developers to pay for grid upgrades to resolve any potential constraints that could be exacerbated by the DER under, regardless of how transitory those constraints might be. This increases costs for DER developers, and delays project development. By contrast, a flexible interconnection allows DER within the existing network to connect without having to wait or pay for network upgrades, provided that the DER owner is willing to accept curtailed access to the grid when the grid is constrained. Under the flexible interconnection model, the DNO uses Active Network Management (ANM) to forecast constraints and manage DER curtailment in real-time to keep the network within safe operational limits. ANM exploits the fact that, typically, network constraints only occur during limited periods when the network is highly used. These types of arrangements are now standard across GB DNOs, and there are innovation projects exploring how access rights could be allocated among DER owners using market mechanisms when the system is constrained.

As discussed above, the wholesale electricity markets in Great Britain are primarily bilateral. So, DER are free to sell wholesale services to buyers already, while the ESO performs a system balancing function (the Balancing Mechanism) and procures system services as needed to support reliability. The balancing services markets are very mature, having operated for over 20 years. Product design is evolving, and market rules are being modified to make markets more accessible for DER (e.g., by reducing minimum size participation thresholds).

Several innovation projects are examining how wholesale and distribution services can be better coordinated, and how conflicts can be addressed. Two innovation projects seeking to test the World B market model are Energy Exchange[37] and IntraFlex.[38] In those projects, DNOs are creating distribution-level markets to solve for different types of network constraints and are experimenting with approaches to prevent conflicts between distribution and transmission system operations. The end goal of these innovation projects is to test simple, transparent rules and processes.

Table 15 - GB DNO market trials

Energy Exchange	Intraflex
• Develop designs for market-based curtailment management for generators with non-firm interconnections • Offers are ranked based on price and sensitivity, i.e., locational closeness to a constraint • Offers are selected based on whether a constraint threshold is breached, and hosting capacity is allocated amongst DER based on their bids and locational sensitivity • Replaces current rules-based approaches to network access (e.g., curtailment based on Last in First Off, or	• IntraFlex tests a short -term market for DNO flexibility which actively accounts for the imbalance it creates in the electricity market on the whole. • Short term (i.e., day ahead) procurement of flexibility services in a continuous market close to real time • Integrated with wholesale balancing market settlement, integrating ESO wholesale prices and settlement into the trial • Fixed activation price per half hour, in future to be developed to be more cost reflective and reflect the real

[36] https://www.energynetworks.org/creating-tomorrows-networks/open-networks
[37] https://innovation.ukpowernetworks.co.uk/projects/energy-exchange/
[38] https://www.westernpower.co.uk/projects/intraflex

Energy Exchange	Intraflex
pro-rata allocation of capacity among connectees) with a market-based solution to curtailment that consider locational sensitivity to a constraint and a bid offer stack	wholesale price in real time, and in line with existing markets • Penalties for non-delivery apply • NODES platform[39] provides a market and brokers bilateral trades between flex providers and the DSO. It may evolve into a market operator in due course.

As a part of the active flexibility market at the distribution-level, all DNOs are actively procuring flexibility products from distribution-connected DER to address network needs.

A.2 Australia Case Study

Australia is one of the world's most active DER markets with upwards of 30% penetration of rooftop photovoltaic solar on residential feeders in some utility territories[40] (i.e., 30% of rooftops have solar PV). Much of the initial deployment of PV solar was driven by very attractive feed-in tariffs (some as high as AUS$0.60/kWh, which is approximately US$0.46/kWh). Although these incentives have now been reduced, high penetrations of PVs have resulted in constraints on distribution facilities, often caused by voltage rise on long radial feeders. The Australian Energy Market Operator (AEMO) projects that the scale and speed of DER uptake across Australia will continue to accelerate as the nation continues to advance its efforts to decarbonize its energy sector.

Distribution Network Service Providers (DNSPs) are focused on developing more robust distribution system operator functions. In particular, there is an increased focus on monitoring and accessing data to improve situational awareness on constrained, low voltage networks. New market platforms have also emerged that enable DNSPs to procure flexibility services (e.g., generation turn down, demand turn up) to mitigate the grid impacts of distribution-connected generation. Substantial variations in DER uptake and network constraints across different states means that the development of new DSO capabilities has progressed more rapidly at some DNSPs than others.

Australia has one of the most mature wholesale energy markets in the world. The National Energy Market (NEM)[41] is an interconnected system which covers the primary population centers along the East and Southeast coasts, while the Wholesale Energy Market (WEM)[42] covers Southwest areas. The NEM and WEM are administered by the AEMO, which manages both the country's electricity and natural gas networks.[43] The AEMO is addressing market, regulatory and technological issues to permit greater DER integration into the NEM. In addition, a number of DER-related programs and initiatives are being undertaken under the auspices of the Energy Security Board[44], Australia's reliability standard organization. The AEMO and Energy Security Board seek to establish a market in which prices are established by buyer and seller interactions.

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[39] https://nodesmarket.com/

[40] https://pv-map.apvi.org.au/

[41] https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/about-the-national-electricity-market-nem
[42] https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem
[43] Some regional transmission assets are owned by state governments and others by regulated private companies.
[44] The Energy Security Board's (ESB) role is to provide oversight for energy security and reliability to Australia. More information can be found here - http://www.coagenergycouncil.gov.au/market-bodies/energy-security-board

Australia's initial approach to interfacing with DER was to evaluate four conceptual frameworks as part of the OpEN project[45], outlined below.

Table 16 – Summary of market options from OpEN project

Model	Description	Pros	Cons
Single Integrated Platform (SIP)	AEMO provides a single route to market for all DER and dispatches them. DNSPs provide constraint information to inform AEMO dispatch scheduling.	• Leverages AEMOs market and operational expertise	• Size/complexity of optimization • Centralization of control functions is perceived as a challenge to existing DNSP business models, as DNSPs currently own this functionality today
Two Step Tiered (TST) Model	Regional DSOs provide the single route to market for DER. DSOs provide optimized DER dispatch schedules to AEMO. We assume each DNSP becomes a DSO.	• Priority resolution of DSO constraints	• Wholesale and distribution systems won't be co-optimized and DER may be underutilized for wholesale needs Heavy reliance on new DSO capabilities • High cost
Independent DSO	Similar to the TST model, but new Independent DSO acts as the route to market and optimizes DER dispatch across each DNSP region.	• Priority resolution of DSO constraints • Addresses perceptions regarding conflicts of interest between DSO and DNSP	• New organizations (DSO) • Highest cost • Potential barrier to efficient DNSP planning and field activities
Hybrid	Single route to market for all DER via AEMO. DNSPs propose optimized dispatch schedule that indicates the hosting capacity available ("operating envelopes"), which AEMO considers as part of a "whole system optimized dispatch schedule".	• Tight coupling to wholesale market • Simplified optimization compared to SIP	• Lower cost/complexity than other models

Upon completion of the project, the industry concluded that variants of the hybrid model were the strongest cases and should be explored in more detail.

Australian DNSPs are now focusing on testing how to implement a hybrid model to by pursuing pilot programs to identify roles and responsibilities as well as the cost of full implementation (e.g., monitoring costs, system and IT costs, market participating costs). One of the pilot programs that is testing the hybrid model is Project Edge[46]. This pilot is a proof of concept for coordinated DER aggregation that is being conducted by AusNet Services[47] (a DNSP in Victoria), Mondo[48] (a retailer), and market bodies AEMO and Australian Renewable

[45] https://www.energynetworks.com.au/projects/open-energy-networks/
[46] https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge
[47] https://www.ausnetservices.com.au/
[48] https://mondo.com.au/

Energy Agency (ARENA)[49]. The main objectives of the pilot are to: 1) demonstrate that AusNet can continue to operate DER markets within safe network limits, 2) maximize energy outcomes (e.g., minimize curtailment), and 3) test various approaches for how a retailer could aggregate DER and then manage operations with AEMO and the DNSP.

Project Edge will demonstrate three different methods for allocating available grid capacity among DER with flexible connection agreements. Under each of the approaches, the DSO will determine the amount of capacity that is available on a distribution network at the feeder or substation level. The DNSP then will define the range of power transfer capacity (generation and load) that can be allowed at each DER connection point without violating distribution system thermal and voltage limits. The differences between each option being examined in each pilot lie in the way transfer capacities are calculated and allocated among DER, along with the role of AEMO. Details of the pilots are outlined below.

Table 17 – Project Edge | Operating Envelopes

Envelope Method	Description
Basic model	• Operating envelopes determined by DSOs are utilized to manage voltage and thermal constraints. • Aggregator bids are made utilizing operating envelope info. • The role of AEMO is to perform bid validation, compare to wholesale clearing price, run dispatch, and carry out settlements.
Bid Optimized model	• Similar to the Basic model however, the operating envelopes are adjusted by the DNSP, based on Aggregator offers and preferences.
The Static Nodal constraints model	• Similar to the Bid Optimized model, however operating envelopes determined by DSOs are only applicable to voltage constraints. • AEMO's dispatch decisions take responsibility for thermal limits provided by networks, and are operated separately to the DSO voltage operating envelopes

The Operating Envelopes model is a simple means to facilitate greater DER participation in wholesale markets and to enhance coordination between the transmission and distribution systems.

A.3 California Case Study

California is well known for its ambitious decarbonization goals and its focus on distributed energy, especially photovoltaics. To enable PV growth, California has looked to demand response and storage to provide needed flexibility. Utilities in California have an energy storage mandate, with targets for deployment of energy storage, with specific goals for transmission, distribution and behind-the-meter connections. Increased deployment of DER, including demand response, are seen as a key component of managing the system and achieving these targets at reasonable cost.

California began developing plans for a DER market in 2013 when the California Public Utilities Commission (CPUC) began requiring utilities to file distribution resources plan (DRP) proposals to help the industry identify the best locations for the deployment of DER. The early stages of California's DER markets focused on making hosting capacity or interconnection capacity assessments (ICA) for the distribution network and developing a locational network benefit assessment (LNBA), which is an analysis of location-specific DER benefits and DER deployment costs.

[49] https://arena.gov.au/

Three large utilities, each owning generation and transmission, dominate the California market. The transmission system operator in California, the California Independent System Operator (CAISO), operates the wholesale power market through a combination of day-ahead and intraday trading and is responsible for maintaining supply/demand balance and system stability. CAISO operates the wholesale electricity market, running day-ahead and real-time markets and dispatching generation to meet demand. California's DER markets have evolved to incentivize non-wires alternatives via programs such as Southern California Edison's Preferred Resources Program (PRP)[50] and by allowing DER aggregations to participate in the wholesale energy and reserves markets operated by CAISO.

CAISO supports two different demand response products: Proxy Demand Resource (PDR) and Reliability Demand Response Resource (RDRR). Both products have day-ahead commitments for energy, but only a resource which qualifies as a PDR may offer energy for real-time dispatch or ancillary services. The California utilities are encouraged to align their local programs with the CAISO products. Participants in utility interruptible load programs, such as large loads (agricultural pumps, industrial and commercial air conditioning, etc.) and even aggregations of small dispatchable loads, typically qualify for a capacity payment and are cross-registered as RDRRs with the CAISO. Utility programs focused on providing economic benefits, especially those that require a commitment to shorter dispatch windows, are aligned with the PDR model. The CAISO's approach for supporting DER is to build on these models; Its Energy Storage and Distributed Energy Resource (ESDER) initiative[51] is working on a series of market changes to enable a broader range of DER resources to readily participate in the wholesale markets.

Following the most destructive wildfire season in California's history in 2018, the focus for distribution businesses has shifted to wildfire mitigation and grid resiliency. Utilities have taken several steps to enable DER to play a role in these efforts, including 1) establishing new standards for interconnection and protective relaying to permit DER to isolate from de-energized networks), 2) encouraging the use of DER to provide power in community resiliency centers, and 3) using DER to provide grid support to allow for retirement or upgrade of high-risk circuits.

California's efforts to promote deployment of DER was initiated to respond to high penetrations of DER (in particular, solar PV) that were creating export constraints on networks. The state sought to create a distribution level pricing concept based on a Locational Net Benefits Methodology (LNBM) and to develop more advanced analyses of hosting capacity. DER markets will continue to evolve in California, but the pace of the distribution level pricing "market" side of DER markets has slowed as focus has shifted to using DER to help address mitigate wildfire risks and reduce the negative impact of the Public Safety Power Shutoff programs.

A.4 New York Case Study | VDER

New York's Value of Distributed Energy Resources (VDER) program is a state initiative that aims to compensate owners of distributed energy resources with tariffs that reflect the true, location-specific, and time-specific value for the energy and other services they export onto the grid. The program is administered by the state's Public Service Commission (PSC) and is designed to promote the development and deployment of DERs by making them more affordable and accessible, thus aiding New York's transition to a clean energy future and reducing its reliance on fossil fuels.

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[50] The Preferred Resources Pilot (PRP) is a multiyear study designed to determine whether clean energy resources can be acquired and deployed to offset the increasing customer demand for electricity in central Orange County. More information on these products can be found here - https://www.sce.com/about-us/reliability/meeting-demand/our-preferred-resources-pilot

[51] https://stakeholdercenter.caiso.com/StakeholderInitiatives/Energy-storage-and-distributed-energy-resources

The VDER tariff, which replaced the flat rate net metering system, compensates DERs on a varying hourly basis and acknowledges that some energy is more valuable at certain times of the day or in specific locations. VDER rates are established well ahead of time to ensure all parties are well versed on the incentive structure and act accordingly. This differs from some other flexibility programs, which might routinely dispatch a DER's energy into a given flexibility product. The program calculates the 'Value Stack' of DERs based on several key components which are listed in Table 18 below:

Table 18 - Value of Distributed Energy Resources Rate Components

VDER Rate Component	Description
Energy Value (LBMP)	Energy value based on NYISO energy prices
Installed Capacity Value (ICAP)	Wholesale capacity value based on NYISO prices
Environmental Value (E)	Social value of avoided GHG emissions
Demand Reduction Value (DRV)	T&D capacity value for utility's system
Locational System Value (LSRV)	Additional T&D capacity value on constrained networks
Market Transition Credit (MTC)[52]	Transition credit related to phase out of net metering
Community Credit (CC)[53]	Additional credit for participating in community DG

In terms of eligibility, the VDER Value Stack is available for excess electricity generated by behind the meter nonresidential projects larger than 750 kilowatts AC, Remote Metered (RM) projects, and Community Distributed Generation (CDG) projects. Projects are up to 5 MW AC and export electricity onto the electric distribution system. Given that VDER compensation is based on grid exports rather than served load, the program's economics generally favor front-of-meter assets. Eligible technologies include solar photovoltaics (PV), stand-alone and co-located energy storage, and other technologies.[54] For resources that do not qualify for VDER (e.g., they are too large), compensation for the energy and other services they export to the grid is provided through buyback service rates, which are based on the NYISO's wholesale prices.

Once the value of energy from the DER has been calculated using the methodology above, this value is then allocated to the offtaker's bill in the form of a bill credit. As is highlighted in Table 14, a temporary Market Transition Credit (MTC) is also included in the program to ensure the transition from net metering to VDER does not disrupt the economics of DER projects. The program was also designed with additional credits (CC) for Community Distributed Generation (CDG) projects to avoid slowing the robust growth of community solar projects across the state. These CC credits provide eligible projects with a supplemental $/kWh rate that is locked in for a 25-year term.

For standalone storage projects, the most critical revenue streams within the VDER framework are LBMP, ICAP, DRV, and LSRV, particularly as this asset class is not eligible for environmental value. With that said,

[52] MTC credit applicable only for Community Distributed Generation (CDG) projects
[53] CC credit applicable only for Community Distributed Generation (CDG) projects
[54] https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Programs/NY-Sun/value-stack-overview.pdf

both LBMP (energy) and ICAP[55] (capacity) fall within the suite of typical wholesale market revenue streams, which leaves DRV and LSRV as the two unique offerings of the VDER program.

The Demand Reduction Value (DRV), which is determined by how much a project's energy is expected to reduce the utility's future needs to make grid updates, is locked in for 10 years. Revenue gained through DRV is based on an asset's generation between 2pm – 7pm throughout the summer months (June-August)[56]. This mechanism, combined with the fact that the NYISO demand peak (ICAP) typically occurs in the summer, means that storage assets earn the majority of their annual revenues in the summer.

In terms of locational signals, the LSRV is available in utility-designated locations where DERs can provide additional benefits to the grid. Each of these utility-designated locations has a limited number of MW of LSRV capacity available. Similar to the DRV, this incentive is also locked in for 10 years in order to provide revenue certainty for developers. Overall, New York's VDER program offers enhanced compensation to DERs based on their contributions to the grid, yet as the grid evolves and the integration of DERs accelerates, the program will necessitate further refinement to offer more adaptive and time-sensitive price signals.

[55] Standalone storage assets must participate in 'Alternative 3' for ICAP, which is paid on kWh injected during a single peak hour of the year
[56] Rates and windows may vary by utility/location

Appendix B Battery Revenue Streams

B.1 Federal Policy

Upon the signing of the Inflation Reduction Act in 2022, the federal Investment Tax Credit (ITC) was extended to standalone energy storage assets with a minimum capacity of 5 kWh. As a result, energy storage installations are now entitled to a base ITC rate of 6%, with a bonus rate up to 30% if the projects are either 1) under 1 MW in capacity or 2) compliant with the new prevailing wage and apprenticeship requirements. While this provision of the IRA will dramatically lower capex for developers and inevitably drive an influx of capital into the battery storage market, it has little effect on the day-to-day dispatch operations of DERs. Therefore, within the context of this project, we view the ITC as a driving force behind storage capacity expansion which is largely agnostic to any kind of temporal or locational signals.

B.2 State Policies

As far as state policy is concerned, Massachusetts has proven a clear commitment to the expansion of DER capabilities. While much can be said about the state's Energy Storage Initiative (2015) and grant programs like the Advancing Commonwealth Energy Storage (ACES) program, the table above (See Table 6 in section 2.4.1) focuses more on initiatives such as the Solar Massachusetts Renewable Target (SMART) program and the newly enacted Massachusetts Clean Peak Standard (CPS), as these programs serve as key revenue streams in the siting, financing, and development of storage assets (and other DERs) across the state of Massachusetts.

As the replacement for the Massachusetts Solar Renewable Energy Credit (SREC I + SREC II) programs, SMART provides additional certainty and incentives for solar developers by offering fixed, long-term, compensation rates for each kWh of solar power generated. On top of base compensation rates, developers can stack additional adders depending on system size, technology type, offtaker, location, and more. Most critically, the SMART program also provides a significant adder of between .0247$/kWh and .0763$/kWh for solar projects with collocated storage systems depending on several sizing and duration qualifications. The revenue stream provided by this lucrative storage adder provides a strong incentive for collocated solar + storage asset development across the Commonwealth.[57]

Another important nuance to the SMART program is that the compensation rates are designed to provide greater incentives for the development of Behind-the-Meter (BTM) facilities over Standalone assets. In the context of this program, standalone facilities are considered to be any facility with no associated load other than parasitic or station load, while BTM facilities refer to any facility that does not meet the standalone criteria, though **both classes must have solar in order to qualify for the program.** While BTM facilities receive a fixed premium above the value of energy for the duration of the tariff term, standalone facilities receive the all-in compensation rate *minus* the value of energy. In other words, as the value of energy rises over the tariff term, standalone projects subsequently receive a smaller compensation rate. Within the context of this project, and given that we are focusing primarily on large (<500 kW) facilities with no parasitic load, assets within the scope of this project would be considered to receive this declining rate for standalone projects.

[57] https://www.mass.gov/doc/smart-launch-and-program-overview/download

With that said, while rates within the SMART program have locational considerations and adders to incentivize preferred development approaches such as brownfield construction and car park canopy conversion, compensation rates within this program are fixed upon COD and paid per kWh generated, regardless of time or location. Therefore, given the largely agnostic incentive provided by the SMART program, Baringa sees little in the way of conflict between participation (revenue generation) in the SMART program and participation in any potential distribution-level incentive program.

In terms of compensation, the SMART program differs dramatically from the Massachusetts Clean Peak Standard (CPS). Stemming from the Act to Advance Clean Energy (2018) and enacted in August of 2020, the MA CPS uses a market mechanism in order to prompt shifts of clean energy to peak demand periods and reduce energy demand during peak periods. The program achieves this by requiring Load Service Entities (EDCs) to procure a rising number of Clean Peak Energy Certificates from participating facilities each year. In order to generate these credits, an eligible facility must operate to store and discharge renewable power, which can be demonstrated by 1) co-locating with a renewable resource (<75% of nameplate capacity), 2) signing a contractual agreement with a non co-located asset, 3) having an Interconnection Service Agreement (ISA) demonstrating resolution of intermittency-based power issues, or 4) having a charging schedule coincident with periods of typically high renewable energy production. [58]

With regard to #4, the program has laid out pre-defined windows in which both wind and solar are typically at their highest grid-scale capacity factors* and has assigned these periods as 'energy storage charging windows'. This window for wind assets occurs overnight, between hour ending (HE) 1 and HE 6, while the window for solar charging takes place during the morning and midday hours, with the window shifting seasonally to reflect seasonal changes in solar irradiance. When it comes to ***discharging*** electricity, the Massachusetts Department of Energy Resources (DOER) has designed the program with four seasonal peak periods to reflect the historic seasonal peaks of the ISO-NE market. According to their analysis of the ISONE peaks, these peaks are defined as:

- **Summer: 3pm – 7pm**
- **Spring: 5pm-9pm**
- **Winter: 4pm – 8pm**
- **Fall: 4pm – 8pm**

By discharging in the Seasonal Peak Periods highlighted above, Clean Peak Resources are eligible to generate Clean Peak Energy Certificates (CPECs), which are then sold to retail electricity suppliers within the state and provide additional revenue to the project.

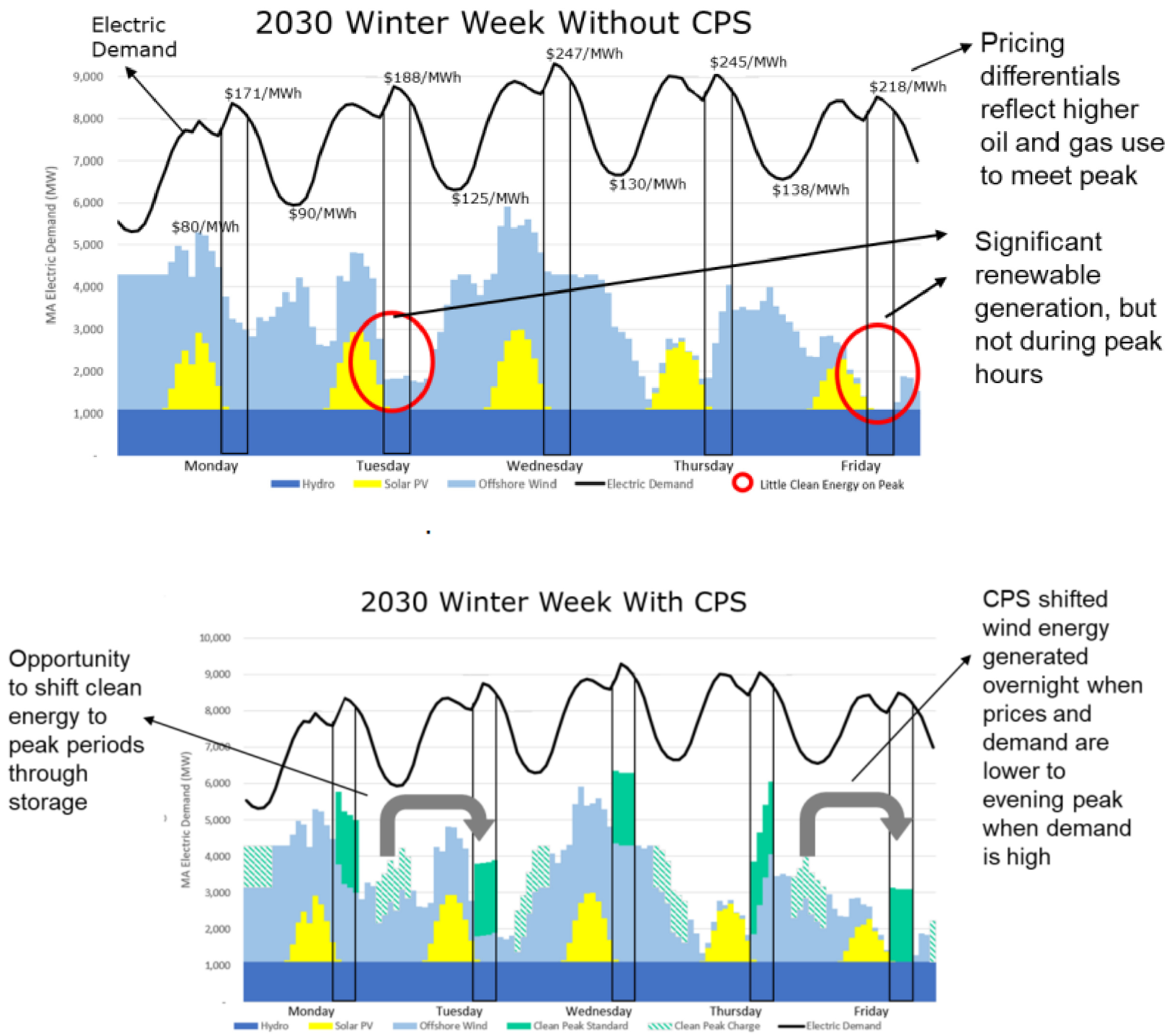
To further align battery discharge schedules with policy objectives, the CPS comes with a series of 'multipliers' which are designed to shift generation toward the time of highest impact. This includes things such as a seasonal multiplier, resilience multiplier, an existing and state contracted multiplier, and most importantly a 25x actual monthly system peak multiplier. While all of these multipliers help to shape dispatch behavior, the actual monthly multiplier (25x) provides the strongest market signal to participating assets.

Given the structure of the CPS incentives, this program provides a clear preference for storage assets to purchase power during periods of higher renewable generation and sell power at periods of peak load. With that said, the dispatch schedule laid out by the CPS incentives is quite similar to the behavior of a storage asset looking to participate in daily energy price arbitrage (discussed in detail later), which is another critical revenue stream for many Massachusetts DERs. In other words, by providing an additional (and lucrative)

[58] https://www.mass.gov/doc/clean-peak-energy-standard-final-regulation/download

revenue stream, the CPS further entrenches the natural behavior of storage assets to arbitrage between off-peak and on-peak prices.[59]

Figure 15 - Illustrative winter week without CPS



B.3 Wholesale Markets

B.3.1 ISO-NE's Forward Capacity Market (FCM)

The Forward Capacity Market (FCM), ISO New England's resource adequacy construct, is an auction-based market mechanisms that ensures that ISO-NE will have sufficient resources to meet the future demand for electricity. Forward Capacity Auctions (FCA) are held annually, three years in advance of each operating

[59] https://www.mass.gov/doc/drafts-cps-reg-summary-presentation/download

period (year).[60] In these auctions, resources compete to obtain a commitment to supply capacity in exchange for a market-priced capacity payment. As the operating period approaches, resources are able to adjust their commitments via a series of reconfiguration auctions, which help to ensure the balancing of capacity in the near-term. While previously storage has been ineligible for several capacity markets, recent FERC filings have helped to open this revenue stream for energy storage assets. In fact, ISO-NE's most recent Forward Capacity Auction (Feb – 2022) closed with more than 700 MW of commitments for new and existing storage resources.

Within the FCM, assets are compensated based on two key metrics: 1) their ability to secure a commitment through the auction and 2) their ability to perform during a capacity event. In order to secure a commitment through the action, a given asset must offer its capacity into the ISO-NE market at or below the price below what clears in the auction. To account for regional capacity needs, ISO-NE is split into several regions, which adds additional granularity to potential clearing prices within the market. After securing a commitment within the capacity auction, assets are then compensated for their availability throughout the operating year. Effectively, these payments are compensation for an assets guaranteed availability, and they serve to cover a number of fixed costs for the asset owner over the operating year.

If, however, an asset with a capacity commitment is **not** able to provide its committed capacity during an ISO-NE emergency event, the asset is not only likely to lose all of its availability payments, but it is also subject to significant penalties of up to $2,000/MWh from the ISO. In 2018, in an effort to address rising generator outage levels and several capacity shortfalls, ISO-NE implemented a strict 'Pay-for-performance' framework that is designed to ensure that generators only receive capacity compensation if they can truly be relied upon during emergency situations. Within ISO-NE, these emergency conditions are referred to as 'Capacity Scarcity Conditions' and they are defined as 'any five-minute interval when system cannot meet reserve requirement'. While these conditions have only occurred (and thus triggered a pay-for-performance event) twice since implementation, the most recent occurrence during December of 2022 undoubtedly looms as a potential risk for asset owners.[61]

In general, while the ISO-NE capacity market offers a valuable revenue stream for DERs, the nature of FCM's availability payments and the rare nature of pay-for-performance events means that the operational lift for DER owners is fairly light relative to other revenue streams. In other words, barring an emergency event or an annual capacity audit, it is very unlikely that a battery asset would be charging/discharging in accordance with FCM market signals on a regular basis. With that said, the severity of penalties posed by the pay-for-performance mechanism creates a dynamic in which the occurrence of scarcity conditions would drive a rapid reprioritization of revenue streams in which an asset would comply with FCM market signals over all other revenue streams to avoid drawing excessive penalties.

B.3.2 Energy Market Arbitrage

Another key revenue stream for many DERs is energy market arbitrage through the wholesale markets. As part of their Day-Ahead Market (DAM), ISO-NE compiles the bids and offers from buyers and sellers of electricity and subsequently clears the market with hourly nodal prices for the next day. Throughout the operating day, a similar market clearing mechanism is run in order to actively balance the supply and demand in real-time (RT). Energy market arbitrage is the act of generating revenue by buying and selling energy products to leverage the natural price differentials between different markets (e.g., DAM or RT) or time

[60] https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/fcm-participation-guide

[61] https://www.iso-ne.com/static-assets/documents/2018/06/2018-06-14-egoc-a4.0-iso-ne-fcm-pay-for-performance.pdf

periods. Most commonly, this involves charging a battery asset during cheap off-peak pricing and then selling that same power back to the grid during peak demand periods.

Due to ISO-NE's reliance on natural gas as the marginal fuel, energy market arbitrage within New England has historically been less lucrative relative to other markets which see marginal fuel switching drive higher greater deviations between on-peak and off-peak prices. With that said, energy market arbitrage remains one of the key value streams for storage assets in Massachusetts today and sees upside revenue potential if the rapid expansion of low-cost renewables helps to drive greater price discrepancies within the market.

From an operational perspective, energy market arbitrage requires optimized hourly scheduling on a daily basis in order to maximize revenue potential. At the moment, price curves within New England are largely shaped by load, which means that the dispatch schedules of DERs participating in arbitrage are fairly predictable. This becomes even more true when accounting for the Massachusetts Clean Peak Standard, which further incentives the discharging of storage assets during periods of peak demand. Ultimately, while the behavior of assets in compliance with both CPS and energy arbitrage tend to align with wholesale grid needs, they do not necessarily align 1:1 with distribution level constraints.

B.3.3 Ancillary Services

Ancillary services are a group of market services, which ensure reliability of the bulk power system at all times and especially during periods of high demand or system emergencies [62]. Across New England, several ancillary service products are available for battery participation, including Reserve, Regulation, Voltage Support, and Blackstart services. Similar to the energy and capacity markets, these services are procured through competitive markets in order to ensure that reliability is provided at the lowest cost. Due to their inherent ability to rapidly charge and discharge, battery storage assets are very well positioned to provide these services, particularly for products with short lead times. Frequency regulation, for example, has historically served as a critical revenue stream for storage assets despite the fact that regulation (and ancillary services altogether) makes up only a small fraction of the wholesale market value stack.

With that said, given the immediate and critical nature of balancing frequency across the system, participation within the frequency regulation market requires significant operational commitment from a participating asset. In order to maximize revenue through the frequency regulation market, an asset must consistently offer regulation capacity into the market, with the offer serving as a commitment to provide balancing services if a significant deviation occurs. As a result, revenue maximizing behavior within this market represents near 24/7 (8760) commitment from an asset.

Another critical point of discussion on ancillary services is the relative size of the market. As was discussed earlier, ancillary services only represent a very small fraction of the (0.5%) of the total wholesale market value. As a result of its size, the ancillary service market sees high risk of market saturation within the next 3-5 years, particularly as battery capacity expands in line with the Massachusetts Clean Peak Standard and the other revenue opportunities highlighted above. Overall, the downward trajectory of ancillary service revenues is projected despite potentially opposing pressure from the proliferation of variable energy resources like wind and solar, which can increase uncertainty within the balancing markets and drive greater need for some ancillary services.

[62] https://www.iso-ne.com/markets-operations/markets/