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JANET T. MILLS
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DAN BURGESS
DIRECTOR OF GOVERNOR'S
ENERGY OFFICE

January 17, 2025

Dear Senator Lawrence, Representative Sachs, and Members of the Joint Standing Committee on Energy, Utilities, and Technology,

This report is submitted by the Governor's Energy Office (GEO) pursuant to [Resolves 2023, Chapter 67] (the Resolve), "Resolve, to Create a 21st-Century Electric Grid."

The Resolve directed the GEO to issue a request for proposals and select a 3rd-party consultant to conduct a study to evaluate whether a distribution system operator (DSO) could be established in Maine to achieve cost savings for customers, improved system reliability and performance, and accelerated achievement of the State's climate goals and growth of distributed energy resources. The GEO retained Strategen Consulting to prepare the initial DSO Feasibility Study as described in Section 2 of the Resolve. The Resolve further directs the GEO to (1) review and evaluate the initial study provided by Strategen Consulting, and (2) determine whether additional feasibility analysis and preparation of a DSO design as described in Section 3 of the Resolve is warranted.

The DSO Feasibility Report and the GEO's determination are contained herewith. The GEO's determination included a request for public comments, which were considered as the consultants finalized the Feasibility Report. The GEO intends to consider this public feedback along with the information and findings contained in the initial study to inform additional areas of analysis to support achievement of the broader objectives of the state related to grid modernization.

The GEO welcomes further collaboration with the sponsor of the Resolve, the Joint Standing Committee on Energy, Utilities, and Technology, and others to facilitate investments in grid planning, infrastructure, and management to most cost effectively advance an affordable, reliable, and clean electric grid for Maine.

Respectfully submitted

Dan Burgess
Governor's Energy Office

Distribution System Operator Feasibility Study

Maine Governor's Energy Office Determination

November 18, 2024

Pursuant to Resolves 2023, Chapter 67 (the Resolve) enacted by the Legislature, the Governor's Energy Office (GEO) selected a consultant to conduct a study to evaluate whether a Distribution System Operator (DSO) could be established in Maine and could be designed to achieve cost savings for customers, improved system reliability and performance, and accelerated achievement of the State's climate goals and growth of distributed energy resources.

Through a competitive request for proposals, the GEO retained Strategen Consulting to prepare an initial DSO Feasibility Study as described in Section 2 of the Resolve. In coordination with the GEO, Strategen Consulting conducted stakeholder engagement and prepared a draft Feasibility Study, attached herein. In the draft study, Strategen Consulting recognizes that a DSO could be designed to achieve the objectives established by the Resolve and recommends additional feasibility analysis.

The Resolve directs the GEO to (1) review and evaluate the initial study provided by Strategen Consulting, and (2) determine whether additional feasibility analysis and preparation of a DSO design as described in Section 3 of the Resolve is warranted.

The GEO recognizes the importance of investing in grid planning, infrastructure, and management to most effectively achieve the state's climate laws. However, it is clear from the Draft Feasibility Study that designing and implementing DSO entities requires significant investment of resources and collaboration, beyond what was contemplated in the Resolve, among a wide range of stakeholders in order to achieve the desired outcomes. Furthermore, while the Resolve requires an analysis of specific DSO functions and roles, it is clear from Strategen Consulting's Draft Feasibility Study that these functions and roles are not exclusively achievable in the context of a DSO, nor even that a DSO is unequivocally the preferred entity to perform such roles. Furthermore, certain roles or outcomes for which a DSO may be designed to achieve may also be achieved through alternative means. Based on these factors, the GEO believes that the development of a detailed DSO design proposal is premature.

Therefore, the GEO's determination is to not pursue the formal creation of a DSO design proposal as described in Section 3 of the Resolve. However, the GEO intends to consider the information and findings contained in the initial study to inform future prioritized areas of analysis to support achievement of the broader objectives of the state related to grid planning, infrastructure, and management, and invites comments from stakeholders regarding this prioritization and potential next steps.

Distribution System Operator (DSO) Initial Study

Prepared for

MAINE GOVERNOR'S Energy Office

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January 2025

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1. Executive Summary

Maine's electricity sector is undergoing a transformative shift aimed at modernizing the grid to improve performance, manage energy costs, and achieve climate objectives. This includes state policies including a Renewable Portfolio Standard (RPS) for 80% renewables by 2030 as well as a reduction in economy-wide greenhouse gas (GHG) emissions of 45% by 2030, 80% by 2050, and reaching carbon neutrality by 2045. Central to this strategy is the integration of Distributed Energy Resources (DERs), which will play a vital role in the state's ambitious energy agenda.

This Report recognizes two primary categories of DERs. The first category is energy assets deployed on customer premises, "behind-the-meter." These include distributed generation (including rooftop solar PV), battery storage, heat pump air conditioning and water heaters, and electric vehicle (EV) charging. Behind-the-meter DER deployment is robust in Maine, including nation-leading rates of heat pump installations and growing distributed solar, and the State is promoting continued DER expansion to achieve shared benefits for energy affordability, resilience, and GHG reductions.

The second category of DERs is distribution-connected "front-of-meter" renewable energy supply resources, such as hybrid solar+storage systems sized to supply energy into the distribution grid. These systems can be deployed on built structures close to load centers, such as roofs of schools, warehouses, shopping malls and parking lots, reducing the need for new transmission capacity, avoiding land-use conflicts, and having the potential to advance Maine's climate goals faster and less expensively than traditional utility-scale solutions.

DERs have historically provided largely passive and lightly coordinated services to the grid, serving as "net load" contributions while the bulk power system is relied on to manage continuous supply and demand balancing. However, there is opportunity for DERs to deliver a more active, and co-equal, set of services to the grid, in a manner that improves renewable energy integration and lowers total system costs. In this manner, DERs can make a substantial contribution to broader energy system reforms that Maine is undertaking, including new utility-scale clean energy sources, bulk (high-voltage) power system upgrades, and transportation, building, and industry transitions as well.

A central question for energy policy is how to maximize the benefits of all types of DER investment for Maine's climate goals, for electricity system performance, and for the state's energy customers. This Report finds that the core distribution system operator (DSO) functions specified in the Resolve, if implemented along the lines described herein, can provide a practical answer to that question.

The traditional approach to electricity service has focused primarily on supply-side investment, to ensure that sufficient bulk generation and energy delivery infrastructure were available to meet consumer demand. However, with the rise of DERs, the landscape is evolving into a more complex and dynamic system in which supply resources can be deployed throughout, necessitating a comprehensive reconsideration of distribution network functions. Responding to the directives of the Resolve, this report describes the core functional capabilities required for a DSO to manage this transition by enhancing system operations, facilitating integrated planning, and administering effective DER market opportunities.

The findings emphasize the need for improved operational visibility, flexible connections, bottom-up resource planning and coordinated market mechanisms that can support DER integration while enhancing system reliability and performance. These are essential functions that need attention under any plausible grid development path; they are core tenets if Maine chooses to pursue a DSO-oriented market design. As Maine continues its journey toward a sustainable energy future, the Report additionally emphasizes the importance of collaboration, transparency, information sharing and innovative practices to achieve the state's climate goals while delivering economic benefits to customers.

By addressing the challenges of integrating DERs and embracing enhanced distribution system functions, Maine can position itself as a leader in the clean energy transition, maximizing the value of its distributed resources and ensuring a resilient and sustainable electricity system for the future.

1.1 Study Approach

Part 1 of the DSO Study is structured to determine whether a DSO could be designed to achieve the objectives outlined in the Resolve.

The Report's approach to this evaluation focuses on assessing the specific set of **DSO Grid Functions** specified in the Resolve that would comprise a prospective DSO in Maine. The Report evaluates these functions in their own right, abstracted from the design complexities of different DSO structural arrangements. In other words, Part 1 examines whether the successful implementation of the core DSO Grid Functions could achieve the Resolve's objectives, before considering the entity or entities in which the DSO Grid Functions would reside. Part 2 of the DSO Study, if authorized by GEO, would examine DSO design options and structural arrangements to assign functions and responsibilities to specific entities in the electricity ecosystem.

To that end, the Initial Study examines whether successful implementation of DSO functions could achieve the Resolve's objectives along the following lines of inquiry:

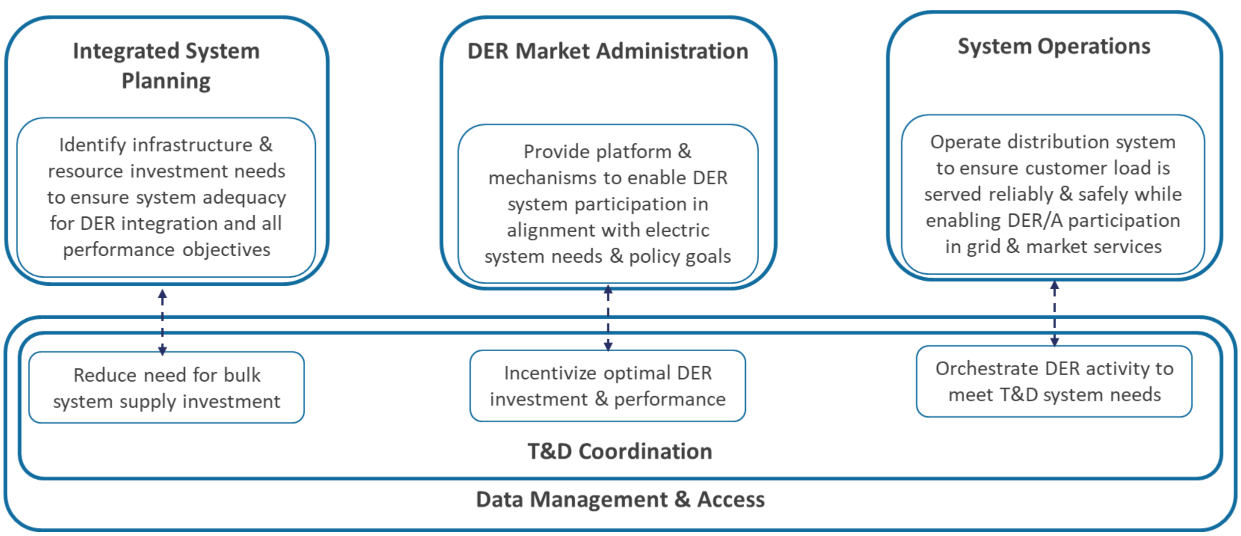
1. **Functional Analysis**: What is the conceptual argument and supporting evidence from existing DSOs, DSO initiatives in progress, or academic and research papers that link implementation of the DSO functions to the Resolve's objectives?

2. **Benefits Assessment Literature Review:** How have other jurisdictions realized benefits from the implementation of the DSO functions discussed herein? How can such benefits help illuminate the potential for DSO functions to support the Resolve's objectives?

3. **Maine Comparative Analysis:** How do Maine's current grid functions compare to the DSO functions as defined by the Resolve, developed in the body of this Report, and implemented through other DSO initiatives globally? What potential gaps in the maturity or sophistication of certain grid functions exist in Maine today, and how might these gaps be addressed to advance achievement of the Resolve's objectives?

1.2 DSO Grid Functions

Traditionally, the performance of large-scale electricity systems — systems for the production, delivery, and consumption of electricity — depends on three core system-operator functions, as identified in the Resolve: real-time operation, the goal of which is to maintain a continuous supply of electricity service to end-use customers; planning to ensure needed resource availability and infrastructure investment; and markets and other forms of economic transactions among system actors. These functional areas are highly interrelated, and expected to be only more so in a high-DER system. For example, the planning and market functions must be co-designed and coordinated to support the real-time operation function. This interdependence of functions is a recurring theme of this report.



System Operations — the continuous supply of electricity to end-use customers to meet a specified standard of reliability — is the most obvious indicator of successful performance. For system operators it entails instantaneous balancing of supply and demand and avoiding or promptly recovering from system contingencies (i.e., outages of critical system facilities).

Integrated System Planning is the necessary preparation of the system to maintain reliable real-time operation. It includes a range of activities between a few days up to several years ahead of the operating day, to ensure adequate system supply capacity and infrastructure are deployed and operational to support continuous real-time balancing without involuntary loss of load.

DER Markets and other forms of economic transactions (such as customer rates, bilateral contracts, grid support services, energy sales and purchases) provide the means to incentivize customer and resource investment and behavior to align with system operation and to recover the costs of the system.

Because these three core functions are related and required for achieving the Resolve's objectives, the Resolve rightfully envisions a DSO performing all three functions.

In addition to those outlined in the Resolve, this report has identified two additional functions that are foundational to support the other three.

Transmission & Distribution (T&D) Coordination reflects the need to enable "whole system outcomes" that optimize benefits across both the distribution and bulk power systems. DSO responsibility should include effective T&D coordination between the DSO and transmission system operator at the T-D interfaces. Given the ISO-NE structure in which most of Maine's load participates, the functional roles and responsibilities of ISO-NE, and the transformative impacts of DER growth on all aspects of the electricity system, DSO-ISO coordination must be addressed in specifying the DSO's operational, planning, and market functions. Throughout this Report, T&D Coordination is addressed within each of the three core DSO Grid Functions rather than as a separate function.[1]

Data Access & Management is an enabling function that recognizes the need to communicate and exchange data between the DSO, the DER operators and the ISO or balancing authority to support and unlock the greatest benefits of high levels of DER participation in the system. This includes end-use customer meter data as well as distribution system data required for efficient DER deployment in locations and with operating characteristics that will be of greatest value. Data management includes acquisition, processing (such as validation), storage or archiving, enabling access by authorized parties, and protection of privacy and security where appropriate. This report does not develop the data management function in detail since it was not identified in the Resolve and it is not necessarily a DSO function like the others. Nevertheless, as Maine evolves its electricity system it will be necessary to address data management and access.

[1] Distribution utilities in Northern Maine interface with NMISA rather than ISO-NE. Although there are some important functional differences between NMISA and ISO-NE – most significantly the fact that NMISA is not its own balancing authority but is part of the New Brunswick Power (NBP) balancing authority – these differences have very little effect on core DSO functions. This report therefore discusses the DSO functions mostly without regard to whether the DSO system is connected to ISO-NE or NMISA, and just indicates differences where relevant.

1.2.1 System Operations

The objective of system operations is to maintain safe, reliable and efficient real-time operation of the distribution network for the dual purpose of: (1) ensuring continuous supply of electricity to end-use customers, and (2) facilitating the participation of DERs to provide (a) operational services to the distribution system and (b) wholesale-market services to the ISO or bulk system operator.

The traditional objective of distribution system operation has been to maintain reliable, safe, and efficient delivery of electricity service to end-use customers in a context where electricity supply has come almost entirely from the bulk transmission system. Customer participation in grid operation has traditionally been limited to demand response services. For a future system with significant amounts of energy supply connected to distribution and expanded participation of customers and diverse DERs in system operation, the optimal design would expand to include integration of DERs into the system and facilitation of their participation in a manner that unlocks and utilizes maximum potential DER benefits.

This report emphasizes the importance of defining operational processes for DER integration, particularly through flexible connections, before detailing specific capabilities. Flexible connections allow DSOs to optimize the integration of DERs using existing grid capacity, reducing the need for costly upgrades. This approach has become widely adopted across regions, including the UK, Germany, Australia, and several states in the U.S., as DSOs increasingly seek efficient solutions for integrating renewable and distributed resources.

A flexible connections regime is complementary to a set of processes and technologies that enable the DSO to coordinate the activities of DERs in a local area to maximize their ability to participate while minimizing any risks to reliable system operation. Such processes and technologies are often referred to as a “DER orchestration” framework and may involve utility control systems such as Distributed Energy Resource Management Systems (DERMS) or operator-side control, as seen in Australia’s dynamic operating envelopes. Effective orchestration will depend on robust technical standards and transparent operational and financial frameworks, enabling DSOs to maintain grid reliability while maximizing beneficial participation of a growing volume and diversity of DERs.

The integration and dispatch of DERs for grid services are vital to modernizing Maine's energy infrastructure. To effectively utilize DERs, a clear definition of grid services is required, specifying capabilities such as energy supply, reserve capacities, regulation, frequency response, and blackstart services. The Pacific Northwest National Laboratory (PNNL) provides a framework that could serve as a foundation for establishing these grid services in Maine. A DSO can adopt less complex approaches in its early or developmental stages by categorizing services based on sophistication levels and following a roadmap approach. Advanced capabilities can be introduced as the DER asset base and operational maturity grow.

DER orchestration is essential for optimizing the use of DERs across various operational contexts, including flexible connections and wholesale market services. Key ingredients of DER orchestration include collaboration with DER stakeholders, alignment with the balancing authority, and ensuring DERs can provide value across all qualified services. Enhanced operational visibility, facilitated by a robust network model and DER registry, is necessary for managing real-time grid conditions and asset performance. Additionally, improved day-ahead forecasting and real-time monitoring capabilities will be instrumental in refining operational planning. Finally, standardization in DER orchestration methods, such as adherence to IEEE 1547 and IEEE 2030.5 protocols, will streamline interconnections and support the seamless integration of DERs into Maine's grid.

A successful DSO will provide all of the above elements of distribution operation, or, depending on the DSO organizational structure Maine adopts, will be able to directly coordinate with other grid entities that may provide some of these elements.

1.2.2 Integrated System Planning

The objectives of integrated system planning are to: (1) ensure that there is sufficient generation and system infrastructure capacity to serve customers reliably, safely and affordably; (2) ensure there is sufficient network capacity to integrate large amounts of DERs; (3) consider all solution options, such as competitive DER solutions and innovative uses of existing assets (e.g., flexible interconnection and grid enhancing technologies), to meet system upgrade needs; and, (4) support integration of distribution-connected renewable generation and storage resources to contribute to Maine's clean energy policy goals.

Market developments in the UK, Europe, and Australia provide some precedent for using the planning process to unlock the benefits of DER. This report suggests, however, that integrated system planning in the Maine context could go further. Other jurisdictions emphasize the use of DERs by the DSO mainly to provide flexibility services. Such services enable the DSO to utilize distribution system capacity to better integrate larger amounts of DERs and support bulk-system operation with higher amounts of utility-scale renewable generation. This report suggests that Maine could, in addition, utilize distribution-connected renewable generation to provide a substantial share of clean energy and accelerate the state's energy goals. A 2016 study by the National Renewable Energy Laboratory (NREL) of the national potential of solar generation deployed on roofs of buildings of all sizes estimated that Maine could provide 60 percent of its annual electricity sales from rooftop solar PV.[2] This large potential compels particular attention to distributed solar-plus-storage within the resource planning process to achieve Maine clean energy goals.

[2] The NREL study examined solar generation potential of all sizes of buildings, with the strategy of exploiting the maximum solar potential of each roof rather than limiting solar installation size to just meet the energy needs of the building itself. The study estimated that the U.S. as a whole could meet 39 percent of its annual electricity sales in this manner. NREL (2016) "Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment"; https://www.nrel.gov/docs/fy16osti/65298.pdf.

A bottom-up integrated system planning approach relies on enhanced visibility and data integration across all distribution network levels, from the customer level where behind-the-meter DERs are deployed, up to the T&D interface substations connecting the distribution system to the balancing authority. The higher distribution voltage levels are the more likely connection points for front-of-meter solar+storage supply resources.

In the UK, Ofgem's DSO baseline expectations advocate for increased network monitoring, especially where it offers clear value for network planning. Key elements of this visibility strategy include adding monitoring capabilities to both primary and secondary systems to inform planning decisions, leverage flexibility services, and address locational constraints in real-time. Distribution utilities like UK Power Networks (UKPN) have prioritized cost-effective, data-first approaches, such as leveraging existing smart meter data, to accelerate visibility enhancements and reduce costs.

Improved visibility enables the DSO to anticipate and respond to changes on a more granular temporal and locational basis. This flexibility aids in managing DER integration, particularly at the secondary system level where variable customer DERs can impact feeder performance. These capabilities are part of the DER orchestration framework mentioned earlier which, if properly accounted for in system planning, can reduce needs for infrastructure investment by enabling the DSO to prevent "worst case" operating scenarios. Worst case scenarios, such as peak system loads that occur a small number of hours each year, and now peak mid-day solar production that can overload circuits, or simultaneous EV charging during peak load hours, can drive costly system capacity investment. DER orchestration by the DSO can manage peak load and peak generation conditions and help to reduce infrastructure costs for ratepayers.

A bottom-up planning process also involves collaboration with local governments to better align supply resource planning with local energy needs, forecast customer DER growth, and design local energy projects to minimize distribution impacts. DSOs should adopt a holistic solution vetting process that fairly assesses the value of DER-based solutions against traditional grid investments. This strategy aims to deploy cost-effective DER solutions to improve grid performance and reduce reliance on bulk system supply by maximizing local energy resources, ultimately facilitating deployment of distribution-connected front-of-meter renewable generation to accelerate and reduce the costs of achieving Maine's clean energy goals.

Finally, coordination with the bulk power system remains vital, particularly to incorporate the impacts of bottom-up resource planning and DER grid services and orchestration to reduce demands on the high-voltage transmission system. As the DSO forecasts residual (i.e., net of local supply) energy requirements to be met through the ISO system and markets, a reduced need for bulk system imports can translate into lower investments in transmission upgrades. DSOs can evaluate local energy supply scenarios to create refined net demand forecasts for bulk system planning, ensuring that the bulk system serves as a residual power source after deploying all cost-effective local DERs.

1.2.3 DER Market Administration

The objective of administering DER markets is to establish and operate a distribution-level market platform and market mechanisms to enable DERs to participate in economic transactions for energy and grid services in coordination with wholesale markets to ensure efficient whole-system outcomes and support reliable whole-system performance.

The UK, Europe, and Australia initiatives on markets and other economic mechanisms for DERs are focused mainly on grid-supporting services such as load flexibility and other forms of load management. These jurisdictions generally define DERs as various asset types that are deployed behind-the-meter (BTM) on customer premises.[3] This report considers a larger definition of DERs that includes front-of-the-meter assets such as solar + storage hybrid generators that can export energy to the system in addition to ancillary grid services.[4] To realize the greatest value from this larger category of DERs, the DSO market administration function for Maine should also include opportunities for front-of-meter resources to participate in distribution-level market transactions.

The market administration function of the DSO is fundamentally built upon the elements of its network operation capabilities, specifically an accurate network model and a DER registry. These elements are critical for achieving effective situational awareness, which ensures real-time understanding of system conditions and DER operational states. Additionally, the market administration function demands settlement-quality metering and data validation to accurately measure and compensate DER performance in delivering energy and core grid services. Depending on the adopted DSO design, this function may encompass the settlement of various DER and DER Aggregation (DERA) economic transactions, including those pertaining to distribution grid services, distribution-level energy supply and wholesale market participation.

The integration of DERs into both distribution and wholesale markets requires a multifaceted approach that addresses the needs of all stakeholders involved. The objectives of the DER provider, the Independent System Operator (ISO), and the DSO must be addressed to ensure a stable revenue stream for DER providers while maintaining reliable service for end-use customers. Pre-operational and real-time activities are essential to facilitate seamless participation of DERAs in ISO markets, encompassing interconnection agreements, operating requirements, and timely communication regarding current operating conditions. Furthermore, the ability of customer-sited DERs to enhance grid resilience and reliability presents new opportunities for their strategic deployment, transforming perceived challenges into innovative solutions. This approach paves the way for a comprehensive DSO market design that not only maximizes the economic value of DERs but also ensures effective coordination with broader wholesale market dynamics.

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[3] Australia uses the term "consumer energy resources" or "CERs" to reflect the fact that the assets in question are deployed by electricity consumers on their premises.

[4] See earlier footnote regarding 2016 NREL study on the technical potential of rooftop solar to supply substantial shares of annual electricity sales in U.S. states.

1.2.4 Data Access and Management

The objective of data access and management is to ensure that all grid actors, including DSO, ISO, and DER market participants, have sufficient data and visibility to perform their functional responsibilities and facilitate the efficient and reliable deployment, operation and utilization of DERs.

Sharing of timely and accurate information between DSOs and other system actors is essential for effective energy management, operational efficiency and system and resource planning. The core data categories are customer data, system data, market data, DER attributes and performance data, and possibly local energy planning data. Customer data includes individual usage profiles, billing information, and participation in rates and programs. System data provides visibility into the distribution network's physical assets and operating limits, including both static attributes crucial for planning and current operating conditions needed for market participation. Market data captures participation details of customers and DERs in various market mechanisms. The DER registry mentioned earlier would include DER asset locations, characteristics, operational profiles, and service commitments. To support the bottom-up resource planning approach described above, the data sharing framework could also include local energy-related planning information such as local clean energy supply projects, electrification initiatives, and planned development projects.

The design of a well-functioning data exchange can follow from descriptions of essential use cases across several functions, including system operations, DER markets, and integrated system planning. For system operations, real-time data exchanges enable effective anticipation of system constraints, flexible connection dispatch, and coordination with the transmission system and wholesale markets. In DER markets, access to granular data is vital for flexibility procurements and market settlements, while integrated system planning relies on comprehensive datasets for project design and siting. To support these use cases, a high-DER electricity system will require modern, scalable data platforms that facilitate easy access, analysis, and response to evolving data needs. Initiatives in both the U.S. and the U.K. highlight the movement towards centralized data platforms that consolidate operational data, customer information, and market participation metrics, ultimately fostering a more responsive and efficient energy ecosystem.

1.3 Findings and Recommendations

This report has been prepared in response to Maine’s Resolve, which directs GEO to engage a third-party consultant to conduct a two-part study on establishing a DSO. The document presents the Initial Study as defined in the Resolve, providing foundational guidance for the subsequent phase of the DSO Study, contingent upon GEO's approval to advance. The primary objective of this initial study is to evaluate the feasibility of designing a DSO that can demonstrably reduce electricity costs, enhance the reliability and performance of the state's electric system, and accelerate the achievement of climate goals while facilitating the growth of DERs.

The findings indicate that the Functions described above, if effectively implemented, can significantly support the integration of DERs and align with the objectives outlined in the Resolve. This report describes essential distribution grid functions, emphasizing the need for modernized distribution system operation capable of integrating high levels of DER participation, market mechanisms that incentivize DER performance to align with system operating needs, and system planning approaches that incorporate DERs in fundamental ways to accelerate Maine's climate goals. Key elements include enhanced system visibility, flexible DER connections, a shift toward integrated system planning that leverages local participation for optimal resource investment, and the establishment of a market platform to enable DER participation in revenue-generating transactions.

Ultimately, this Initial Study concludes that a well-designed DSO, defined by advanced grid functions, can achieve the Resolve's stated objectives, ensuring a more resilient and cost-effective clean energy future for Maine.

2. Introduction

Maine's electricity sector is evolving rapidly as the state makes progress toward a 80% renewable portfolio standard by 2030 and climate goals of decreasing reductions in greenhouse gas (GHG) emissions by 45% by 2030, 80% by 2050, and carbon neutrality by 2045.[5] Distributed energy resources (DERs) are a significant component of the state's changing electricity system, which provide affordability, resilience, and environmental benefits but require attention to optimally integrate onto the grid.

Traditionally, linear electricity value chains gave particular attention to managing the supply-side of the system. This ensured sufficient bulk generation connected to the transmission system was always available to be dispatched to meet varying levels of consumer demand. Distribution networks primarily functioned as a one-directional means for transporting electricity to largely passive ratepayers located downstream. Accordingly, the objectives, roles and responsibilities of conventional distribution utilities reflected this long-established status quo.

With the rise of both cost-competitive utility-scale and distributed forms of Variable Renewable Energy (VRE), however, electric power supply is less dispatchable and flexible. At the same time, with the rise of EVs, heat pumps and fuel substitution, the electrification of transport, heating and industrial processes is driving electricity demand upward as the overall proportion of flexible resources connected to the distribution system increases.

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[5] Renewable Portfolio Standard | Governor's Energy Office (https://www.maine.gov/energy/initiatives/renewable-energy/renewable-portfolio-standard) and LD 1679.

Globally, in recognition of the new roles in supply-demand matching and whole-system optimization that the demand-side must play, many distribution systems are now being transformed to function in a more adaptive and bidirectional manner. Consistent with international trends, it is plausible that Maine's electric power system in general, and distribution systems in particular, will similarly need to transition for an increasingly dynamic future; one where conventional generation, utility-scale VRE and millions of distribution-connected DERs and flexible resources must be made capable of functioning together more holistically.

Tackling this complex transformation with conventional, linear approaches to planning, operations, rate structures and functional responsibilities is proving inadequate, with the potential for increasing customer and system risks and costs. Globally, this recognition has provided the impetus for several countries to investigate and implement alternative distribution system functional designs and structures which reflect the growing importance of an active and responsive demand-side. For example, the United Kingdom, Australia and the European Union are currently investigating or already transitioning to Distribution System Operator (DSO) models that enhance whole-system flexibility and optimization while enabling utility-scale VRE and millions of DERs to be more deeply integrated.

As a result, there is growing evidence that such a holistic approach can not only enhance the benefits to individual DER adopters but also drive whole-system benefits and cost savings for all ratepayers, including those without DER or EVs. Further, given that well-integrated VRE and DER will reduce dependence on carbon-intensive generation sources, it can play a vital role in achieving Maine's climate goals in a reliable, equitable, and cost-effective manner.

With the passage of L.D 952[6] ("the Resolve"), Maine is the first jurisdiction in the United States to follow suit and conduct an exploration of the feasibility of a DSO. This report is intended to be the first step in this assessment and provide guidance on subsequent evaluation steps if deemed appropriate.

Distributed Energy Resources (DER)

Although the Resolve does not explicitly define DER, this report uses the term to refer to a diverse category of devices that are connected at the distribution level, either directly to a distribution utility's wires or behind the utility meter at end-use customer premises, and are capable of providing beneficial services to the wider electric system. Examples include distributed generation and storage, EVs and charging stations, grid-interactive buildings and microgrids, as well as more traditional demand response, flexible loads, and energy efficiency strategies.

[6] https://www.mainelegislature.org/LawMakerWeb/summary.asp?ID=280086912

3. The Resolve's DSO Study Scope

This Report has been developed in accordance with L.D. 952[7] ("the Resolve"), which directed the Governor's Energy Office (GEO) to select a third-party consultant to conduct a two-part study regarding the establishment of a DSO. This Report represents the Initial Study ("Initial Study" or "Part 1") as outlined by the Resolve and provides high-level guidance on DSO Study Part 2, if GEO deems it appropriate to proceed.

The Resolve defines a DSO as an entity designed to serve the following roles for the State:

- Oversee integrated system planning for all electric grids in the State, including coordinating energy planning efforts across state agencies;
- Operate all electric grids in the State to ensure optimum operations, efficiency, equity, affordability, reliability and customer service;
- Administer an open and transparent market for distributed energy resources; and
- Facilitate the achievement of the greenhouse gas reduction obligations and climate policies pursuant to the Maine Revised Statutes, Title 38, section 675-A and section 576-A and section 577, subsection 1.

It is important to note at the outset that these functional roles, and indeed the evolving operational objectives they serve, do not exist in abstract isolation and cannot be assessed outside the current Maine context. The existing utilities in Maine have been operating and planning their distribution networks for decades with the primary purpose of transporting electricity generated at the bulk power system to customers connected to a local distribution circuit. What is new is that hundreds of thousands of customers are now (or will soon be) investing in their own sources of renewable energy generation, storage, demand-side flexibility, and EVs. These customer adoption trends continue to accelerate – not only in Maine but in many parts of the world.

As noted above, traditional, legacy distribution utility functions evolved in a context where almost all generating resources were located upstream, connected to the transmission system. Historically, customers were largely considered to be passive 'takers' of the electric service provided and the distribution function was primarily one of transporting electricity generated upstream to consumers located downstream.

The emergence and rapid growth of both utility-scale VRE and DERs revises many of these decades-old assumptions. For example, generation, storage, and flexible resources can now be located anywhere on the grid – being either transmission- or distribution-connected. In addition, rather than merely being passive receivers of kilowatt-hours, customers with various types of DERs can now choose to participate in the provision of beneficial grid services in exchange for some

[7] L.D. 952, An Act to Create a 21st-Century Electric Grid.

form of compensation. In this context, the role of the distribution system as an integral part of lower carbon, self-balancing electric power systems only continues to expand as the level and importance of distributed generation, storage and flexible resources grows.

The concept of a DSO arises in this context due to the significant physics-based implications that emerge in this increasingly volatile operational environment. Rather than remaining solely the means of transporting electricity to downstream consumers, individual distribution systems increasingly require more dynamic management within their service territory and a far more interactive relationship with the bulk power system. To that extent, the various DSO models being considered globally are all somewhat analogous to various roles played by a conventional bulk power system operator, albeit focused on high-DER distribution systems.

The Resolve directs the Initial Study to evaluate whether a DSO could be designed to achieve the following objectives:

- A demonstrable reduction in electricity costs for customers;
- Improved electric system reliability and performance in the State; and
- Accelerated achievement of the State's climate goals and growth of distributed energy resources.

If the consultant's initial study concludes that a DSO can be designed to achieve the three objectives stated above, and the GEO agrees with that conclusion after review and evaluation of the Initial Study, the GEO shall authorize the consultant to proceed with the second part of the study.

Per the Resolve, Part 2 of the DSO Study shall develop a DSO design proposal and identify the scope and characteristics of a prospective DSO for Maine.

Finally, if a design proposal is developed in accordance with section 3 of the Resolve, the GEO shall evaluate the proposal and prepare a final report and recommendation including the following elements:

- Identification of the costs and benefits of creating the DSO, including the staffing and budget needed for the operation of the DSO;
- A description of the DSO's role in accelerating the achievement of the State's climate goals and growth of distributed energy resources;
- Identification of potential improvements in electric system reliability and performance that the DSO would bring to the State;
- An evaluation of whether and how the DSO would affect equity in energy access and affordability throughout the State;
- GEO's recommendations regarding whether the State should establish the DSO;

- If the GEO recommends that the State establish the DSO, the report shall include:
    - Identification of the state agency within which the DSO might best be established;
    - Suggested changes to electric rate-making policy and regulations that may be necessary to implement the DSO;
    - A description of the regulatory authority, if any, that should be provided to the DSO; and
    - A description of the steps necessary to establish the DSO, including legislation for its implementation.

Section 4 outlines the Report's approach to Part 1 of the DSO Study.

4. DSO Study, Part 1 - Assumptions and Methodological Approach

This Report views its evaluation of a prospective DSO as one inherently centered on examining DER integration and orchestration within Maine's distribution systems and in a manner that can provide benefits for the wider electric system. And, importantly, how the Resolve-defined DSO functions, if well-implemented, could help achieve the Resolve's stated objectives via benefits attendant with enhanced system efficiency, flexibility, and reliability.

This Report's Initial Study evaluation approach is primarily informed and shaped by the very language of the Resolve itself. The Resolve explicitly identifies the growth of DERs as a key objective against which a prospective DSO design should be evaluated in the Initial Study and identifies the administration of an open and transparent market for DERs as an integral function of a DSO design. When identifying the potential scope and characteristics of a DSO design to be potentially explored in Phase 2 of the DSO Study, the Resolve outlines numerous elements focused on the integration and utilization of DERs across the electricity system. This includes: (i) the operation of an open market for DER; (ii) integrated distribution planning that incorporates non-wires alternatives (NWAs), load management and energy efficiency along with the efficient integration of DER; (iii) informing DER market participants regarding locational capacity mapping; (iv) scheduling and controlling energy storage system discharge within the distribution grids, including vehicle-to-grid systems; and (v) optimizing operations, infrastructure growth, demand management and energy efficiency programs for all transmission and distribution utilities using real-time data.[8]

[8] L.D 952, An Act to Create a 21st-Century Electric Grid.

This Report's interpretation of the centrality of DER to the DSO Study evaluation is consistent with other jurisdictions' approaches to the topic globally. The leading international examples of DSO initiatives are oriented around objectives and anticipated benefits of DER growth and integration in a manner similar to the objectives, functions, and prospective design criteria outlined by the Resolve.

The United Kingdom's independent energy regulator, Office of Gas and Electricity Markets (Ofgem), launched its DSO investigation with the premise that decarbonization, digitalization and decentralization are progressively embedding themselves across the energy system and that this opens up a number of opportunities, including more efficient network use, new ways for consumers to manage their energy and earn new revenue streams, and realizing a low carbon economy. Moreover, Ofgem states these interests are best protected by an energy system that can attract investment and innovation and keep costs as low as possible, while also promoting sustainability. Specifically, realizing the value flexibility providers provide via their DERs is vital to achieve an efficient system and deliver decarbonization at least cost to consumers.[9]

In the European Union, the Fit for 55 (FF55) package and energy legislative files outline the EU's target of reducing net greenhouse gas emissions by at least 55% by 2030.[10] In this wider context, the EU DSO Entity was established and legally mandated as the official EU body for European DSO's. Given the increasing role of distribution-connected DER for realizing the EU's decarbonization ambitions, Active DSOs[11] are increasingly recognized as key to facilitating the deployment of distributed renewable energy and accelerating the integration of electric vehicle charging. They are also seen as playing key roles in supporting whole-system reliability and optimization through coordinated planning and operational interaction between DSO and TSO networks and enabling system flexibility solutions underpinned by data access and interoperability. In the aftermath of the war in Ukraine, FF55 obligations were further reinforced with even more ambitious targets for the deployment of renewables highlighting the role of DSOs in energy security.[12]

In Australia, which now has the world's highest per capita deployment of rooftop solar photovoltaics (PV), significant efforts are advancing at state and federal levels to deeply integrate DER and advance the transition of conventional distribution networks to DSOs. For example, the state of Western Australia released its DER Roadmap in 2020 featuring the need to assign DSO responsibilities and has subsequently advanced a significant program of work to map out and trial

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[9] https://www.ofgem.gov.uk/publications/ofgem-position-paper-distribution-system-operation-our-approach-and-regulatory-priorities, at 8.

[10] Fit for 55 - The EU's plan for a green transition - Consilium (europa.eu)

[11] The term Distribution System Operator (DSO) is used generically of conventional distribution utilities in the EU. The term Active DSO tends to be employed to describe utilities that are transforming to actively integrated and coordinate DER in a high-DER context and is therefore synonymous with how the term DSO is used elsewhere.

[12] https://www.eudsoentity.eu/publications/download/84

DSO functions and roles.[13] Similarly, while many details are yet to be resolved, the state of Queensland has also committed to transitioning its major distribution business into performing DSO functions. Further, Australia's national science agency, CSIRO, has undertaken significant work to examine and develop future power system architectures for a high-DER future which include a significant focus on DSO models.[14] Australia's federal government has also commenced the National Consumer Energy Resources Roadmap process which includes a dedicated stream that is focused on the guiding the transition to DSO models nationally.[15]

Thus, to comply with the Resolve's direction and informed by international precedent, the Initial Study examines whether the Resolve-specified DSO functions, if well-implemented and irrespective of any specific DSO Structure Design, could help to enable cost-effective DER integration and to facilitate further DER growth in a manner that meets the Resolve's stated objectives.

Discovery and Stakeholder Engagement

The team conducted discovery and stakeholder engagement to compile insights and references to inform the development of the Part 1 report. Our approach was grounded in gaining this information from three perspectives:

- **Maine:** Any DSO analysis must be considered in the Maine context, and thus, a deep understanding of past and ongoing initiatives in Maine is critical to developing any study.
- **United States:** While a DSO has not formally been created in the US, several states have ongoing initiatives addressing one or more DSO functions described in the resolve. Understanding the progress in other states can provide meaningful context on Maine's progress towards these functions compared to its peers within a similar regulatory construct.
- **International:** The international community has made significant progress towards advancing different versions of the DSO concept and represents the most valuable source of information on the current state of DSOs.

Moreover, the team took a dual approach to discovery and stakeholder engagement:

- **Discovery:** The team used discovery in most scenarios to surface domestic non-Maine specific insights given the team's significant experience working on these issues across the United States.
- **Discovery + Stakeholder Engagement:** The team used a combination of discovery and stakeholder engagement to gain Maine-specific and international insights. Specifically, the

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[13] DER-Roadmap_April2020.pdf (brighterenergyfuture.wa.gov.au)

[14] https://www.csiro.au/-/media/EF/Files/GPST-Roadmap/Final-Reports/Topic-7-GPST-Stage-2.pdf

[15] national-consumer-energy-resources-roadmap.pdf

team conducted discovery to inform interview questions for stakeholder engagement and further conducted additional discovery based on recommendations from stakeholders.

Stakeholder Interviews

The team conducted 25+ interviews across four countries and the European Union with a diverse set of stakeholders, including individual utilities, utility trade associations, balancing authorities, regulators, and consultants, which includes the following:

Maine

- Central Maine Power
- Versant Power
- Eastern Maine Electric Cooperative
- Fox Islands Electric Cooperative
- Efficiency Maine Trust
- Office of the Public Advocate
- Independent System Operator New England
- Northern Maine Independent System Administrator
- Coalition for Community Solar Access
- Rep. Walter Gerard Runte, Jr.

United Kingdom

- Office of Gas and Electricity Markets
- United Kingdom Power Networks
- Scottish & Southern Energy Networks
- Energy Networks Association
- Baringa Consulting

European Union

- E.ON
- Alliander
- European Union DSO Entity
- Danish Technical University
- ECCO International

Australia

- South Australia Power Networks (SAPN)
- AusNet Services
- Australian Energy Market Operator
- Varied Consulting
- Energy Horizons

Canada

- Ontario Independent Electricity System Operator (IESO)

The contents of this Initial Study are solely those of the authoring team and do not represent the views of these organizations or their representatives interviewed.

4.1 DSO Design - Core Components

The Resolve explicitly calls for a conclusion in Part 1 of this study on whether a DSO *could* be designed to achieve the stated objectives and, if the consultant comes to this conclusion and GEO agrees, to develop a design proposal in Part 2.

As a threshold matter, it is important to recognize that the design of a DSO consists of several distinct core components, including:

- **DSO Grid Functions:** those grid functions required to manage a reliable distribution grid in a high-DER power system, starting from descriptions of the three core DSO functions specified in the Resolve (integrated system planning, system operations, and DER markets administration).
- **DSO Structure:** definition of roles and responsibilities of a DSO as an entity within the power system, with consideration for the DSO as it relates to and interfaces with other key entities that comprise the electricity system, along with their respective roles and responsibilities.
- **DSO Regulatory Framework:** specification of the regulatory structure that governs a DSO's operation, establishes incentives for optimal performance and the revenue model by which it recovers its costs, and provides for oversight and accountability to perform its core functions.

Each of these DSO design core components is complex in isolation and requires a significant amount of analysis, with several design decision points within each core component. Other jurisdictions have conducted DSO initiatives that leveraged lengthy stakeholder participation processes, including workshops and workshop reports, specification and assessment of alternative DSO models, and regular interactions with regulatory authorities. Such inquiries have unfolded over the course of several years.

In contrast, the Maine DSO Study is directed to proceed on a relatively short timeline, consisting of two parts. Part 1 will focus on the **DSO Grid Functions** and, specifically, whether the DSO Functions identified in the Resolve *could* be designed to achieve the Resolve's objectives. This assessment is to occur in isolation without consideration for a specific **DSO Structure** design or the particulars of a **DSO Regulatory Framework**. Such an approach is consistent with Resolve's guidance for Part 1 of the DSO Study as outlined above.

Section 5, below, examines, in detail, three core DSO Grid Functions.

Part 2 of the DSO Study, if authorized by the GEO, would explicitly address **DSO Structure** design, outlining a conceptual mapping and delineation of the functions and responsibilities of the DSO and its relationships with transmission and distribution utilities and government and quasi-governmental agencies to include regulatory, planning, ownership, and market administration functions. If GEO authorizes Part 2 to move forward, Part 2 of this study will address DSO Structure design, to include, but not be limited by, the consideration of a single statewide DSO.

Finally, the Resolve directs that should a DSO design be developed in Part 2 it include GEO's recommendations regarding suggested changes to electric rate-making policy and regulations that may be necessary to implement the DSO; a description of the regulatory authority, if any, that should be provided to the DSO; and a description of the steps necessary to establish the DSO, including legislation for its implementation. Accordingly, if Part 2 of the Study moves forward, it will include high-level guidance on key considerations for the design of a **DSO Regulatory Framework** to be considered in subsequent processes as recommended by GEO.

4.2 DSO Study, Part 1 - 'DSO Grid Functions' Evaluation Approach

Part 1 of the DSO Study has been structured to determine whether a DSO *could* be designed to achieve the objectives outlined in the Resolve.

The Report's approach to this evaluation focuses on assessing the specific set of **DSO Grid Functions** that would comprise a prospective DSO in Maine. These functions are evaluated in their own right, abstracted from the design complexities of different DSO Structures. In other words, Part 1 examines whether the successful implementation of DSO Grid Functions could achieve the Resolve's objectives without regard for the particular entity or entities in which the DSO Grid Functions would reside.[16]

Given the centrality of DER integration and utilization to the DSO value proposition, Part 1 assesses the extent to which successful implementation of DSO Grid Functions could better enable DER integration and proliferation and examines the various categories of benefits that could be realized as a result.

[16] As noted above, if authorized by GEO, Part 2 of the DSO Study would analyze the DSO Grid Functions in the context of conceptual DSO design details across two or more DSO Structures – investigating roles and responsibilities for specific entities in the electricity ecosystem.

To that end, the Initial Study interrogates whether successful implementation of DSO functions could achieve the Resolve's objectives along the following lines of inquiry:

4. **Functional Analysis**: Is there conceptual evidence from existing DSOs, DSO initiatives in progress, or via academic or research papers that indicate implementation of the DSO functions can achieve the Resolve's objectives?

5. **Literature Review Benefits Assessment:** Have other jurisdictions realized benefits from the implementation of the DSO functions discussed herein? Can such benefits help to illuminate the potential for DSO functions to support the Resolve's objectives?

6. **Maine Comparative Analysis:** How do Maine's current grid functions compare to the DSO functions as defined by the Resolve and advanced grid functions implemented through other DSO initiatives globally? Are there potential gaps in the maturity or sophistication of certain grid functions in Maine today, and how might functional maturity gaps impact the achievement of the Resolve's objectives?

Functional Analysis

The analysis examines DSO functions in detail, with specifics grounded in global best practice as reflected in DSO research, the formalization of DSO functions and their practical implementation. This is complemented by consideration of the physics-based implications of various DSO models for both the bulk power system and related distribution systems given that they must operate in a far more dynamic, adaptive and interdependent manner in a high-DER future.

As such, the functional analysis explores the characteristics of each DSO function and how these functions would work together to enable more effective DER integration, utilization, and system optimization. While it is important to note that the distribution utilities and other entities have historically performed some aspects of these functions, they have been primarily oriented around the role of one-directional transport of electricity to largely passive consumers.

Literature Review Benefits Assessment

Informed, in part, by insights gained through the functional analysis, the Report conducts a literature review to surface benefits attributable to DER utilization and proliferation resulting from the successful implementation of DSO functions. Importantly, this literature review was supplemented by a series of interviews of relevant regulatory and utility experts across the United States, the United Kingdom, Australia and the European Union.

Maine Comparative Analysis

It is important to recognize that Maine's distribution utilities and other entities are currently evolving their grid functions and making investments that have relevance to some aims of the Resolve. That said, aspects of these grid functions may not be to the same level of maturity or sophistication as the DSO functions outlined by the Resolve or implemented in the global best practice DSO examples studied, nor explicitly directed toward the same overarching objectives. As such, this comparative analysis seeks to outline the current state and illuminate opportunities for the evolution of grid functions toward those that can better support the achievement of the Resolve's objectives.

5. Functional Analysis

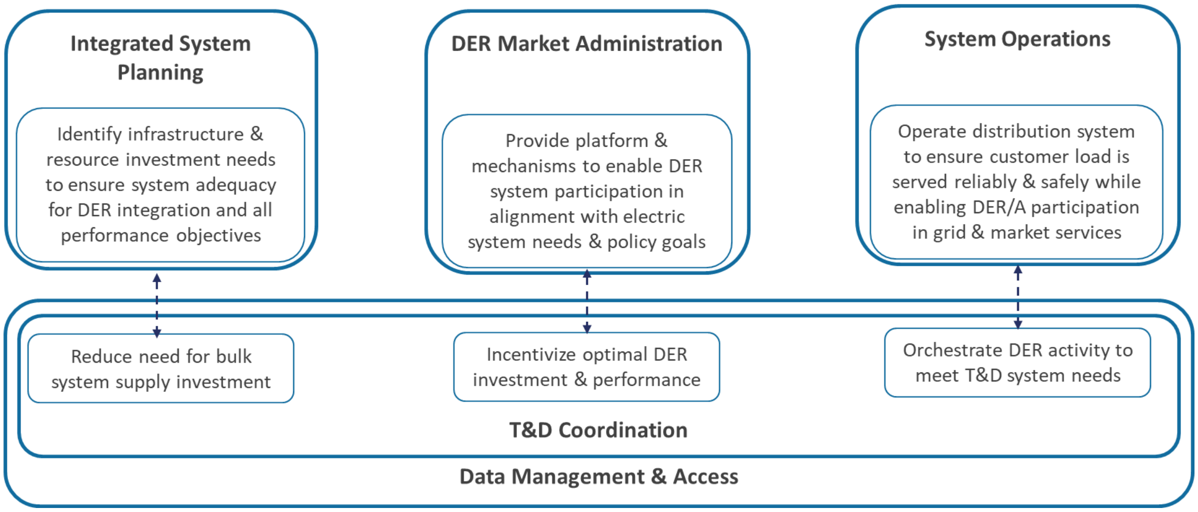
For Part 1 of this study, this report assesses whether a DSO could be functionally designed to integrate and utilize DERs and thus achieve the Resolve's objectives as outlined above. The Resolve defines a DSO's functions[17] or roles as the following:

- **Integrated System Planning:** Oversee integrated system planning for all electric grids in the State, including coordinating energy planning efforts across state agencies.
- **Distribution System Operations:** Operate all electric grids in the State to ensure optimum operations, efficiency, equity, affordability, reliability, and customer service.
- **DER Market Administration:** Administer an open and transparent market for distributed energy resources.

5.1 Interrelationship of Core DSO Functions

Traditionally, the performance of large-scale electricity systems — systems for the production, delivery, and consumption of electricity — depends on three inter-related core system-operator functions, as identified in the Resolve: real-time operation, whose goal is to maintain a continuous supply of electricity service to end-use customers; planning to ensure needed resource availability and infrastructure investment; and markets and other forms of economic transactions among key system actors. What is often not fully recognized is that these three core functions are highly interrelated. For example, the planning and market functions must be designed and performed to support the real-time operation function. This interdependence of functions is a recurring theme of this report.

[17] Of note, the Resolve also lists "[f]acilitate the achievement of the greenhouse gas reduction obligations and climate policies" as a role for a DSO in Maine. Greenhouse gas reduction and climate policies were not part of the traditional performance expectations of electricity systems in the 20th century, but have now risen to a high policy priority across many jurisdictions today. Notwithstanding the importance of this role as identified by the Resolve, this is not a functional activity similar to the first three functions. Accordingly, this report treats this element as a Resolve objective rather than an explicit DSO function.



System Operations—the continuous supply of electricity to end-use customers to meet a specified standard of reliability—is the most obvious indicator of successful performance. For system operators, this entails instantaneous balancing of supply and demand and avoiding or promptly recovering from system contingencies.

Integrated System Planning is the necessary preparation of the system to maintain continuous, reliable, real-time operation. It includes a range of activities between a few days up to several years ahead of the operating day to ensure adequate system infrastructure is deployed and operational to support continuous real-time balancing.

DER Markets and other forms of economic transactions (such as retail rates, bilateral contracts, energy sales and purchases) provide the means to incentivize customer and resource behavior to align with system operation and to recover the costs of the system.

Because these three core functions are interrelated and required for achieving the Resolve's objectives, it is logical that the Resolve envisions a DSO performing all three functions.

In addition to those outlined in the Resolve, this report has identified two additional functions that are applicable across each of the three core functions.

Transmission & Distribution (T&D) Coordination reflects the need for DSOs to enable "whole system outcomes," enabling optimized benefits across both the distribution and bulk power systems. DSO responsibility should include effective T&D coordination between the DSO and ISO-NE at the T-D interfaces.[18] Given the ISO-NE structure in which most of Maine's utilities participate, the functional roles and responsibilities of ISO-NE, and the transformative impacts of DER growth

[18] Distribution utilities in Northern Maine interface with NMISA rather than ISO-NE. Although there are some important functional differences between NMISA and ISO-NE – most significantly the fact that NMISA is not its own balancing authority but is part of the New Brunswick Power (NBP) balancing authority – these differences have very little effect on core DSO functions mostly without regards to whether the DSO system is connected to ISO-NE or NMISA, and just indicates differences where relevant.

on all aspects of the electricity system, DSO-ISO coordination must be addressed in specifying the DSO's operational, planning, and market functions.

Data Access & Management is a supporting function that recognizes the need to communicate and exchange data from the DSO to DER operators and the balancing authority, given the distribution system's more prominent role in a future state with high levels of DER integration. This includes end-use customer meter data as well as distribution system data needed to enable efficient DER deployment in locations and with operating characteristics that will be of greatest value. Data management includes acquisition, processing (such as validation), storage or archiving, enabling access by authorized parties, and protection of privacy and security where appropriate. This report does not develop the data management function in detail since it was not identified in the Resolve and it is not necessarily a DSO function like the others. Nevertheless, as Maine evolves its electricity system it will be necessary to address data management and access.

5.1.1 Lessons Learned from Other Jurisdictions

UK Experience. The UK regulator, Ofgem, provided guidance on DSO functions, stating that these include functions that the UK distribution network operators (DNOs) have delivered historically, functions that will need to be enhanced, and functions that are entirely new.[19] Ofgem's considerations were informed by a number of wider industry-led initiatives in the UK, in particular the Energy Network Association's Open Networks program which commenced work on DSO models in 2017.[20] Ofgem subsequently released a position paper[21] in 2019 on a proposed

[19] Ofgem, RIIO-ED2 Methodology Consultation: Overview, at 53. https://www.ofgem.gov.uk/sites/default/files/docs/2020/07/ed2_ssmc_overview.pdf

[20] https://www.energynetworks.org/work/open-networks/

[21] OFGEM DSO Position Paper: https://www.ofgem.gov.uk/sites/default/files/docs/2019/08/position_paper_on_distribution_system_operation.pdf

approach to implementing a DSO which aligns with the Resolve, identifying similar key functions to those identified in the resolve as described below.

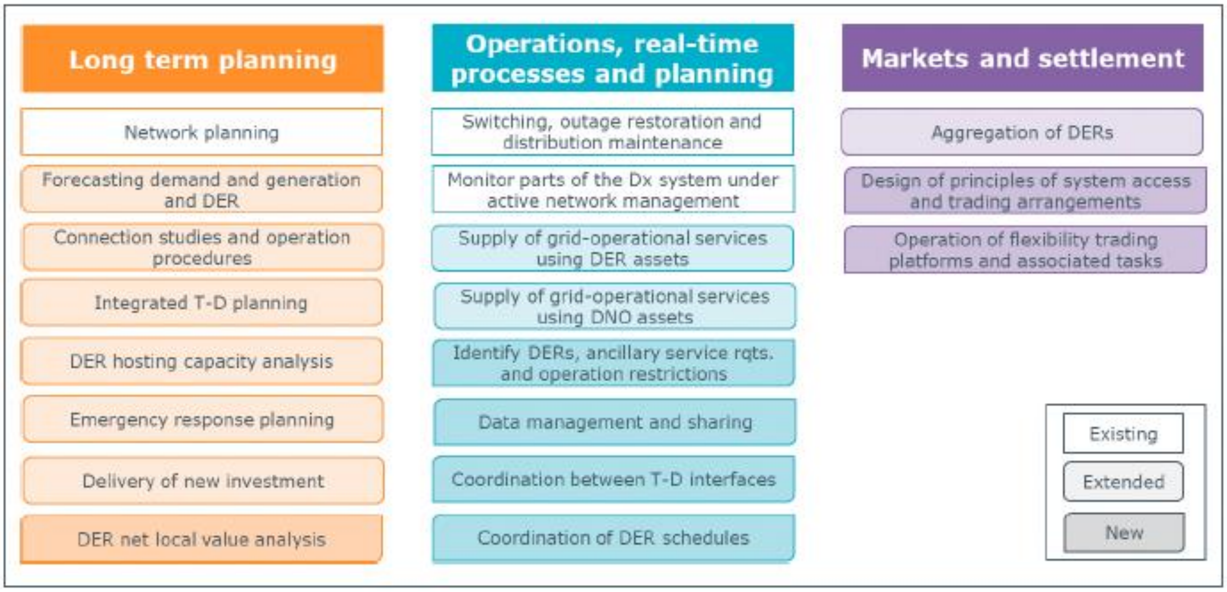


Figure 1 Ofgem DSO Poisition Paper - Functional Breakdown of DSO

These key DSO functions have remained relatively consistent in the UK, now being called planning and network development, network operation and market development[22], with each DSO being required to develop their DSO business plans in the context of these functions. The Ofgem paper also identified two entirely new functions that are applicable across each of the three core functions above: T&D coordination and data sharing.

Ofgem has emphasized the need for whole systems outcomes. As shown in the diagram above, T&D functions should be integrated into planning and operations. Ofgem also has emphasized coordinating the development of distribution-level markets, associated procurements, and dispatch of flexibility with the ESO to ensure efficient whole system outcomes.[23]

Ofgem has also stated that a key enabler for DSO across these categories is data, stating that network companies should make network data visible and share this in an open, interoperable way, to better support the emerging and existing markets and to embed whole system outcomes.[24] Ofgem also emphasizes the need for DSOs to collect sufficient information on DER characteristics and parameters[25] among other types of DER data.

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[22] https://www.energynetworks.org/work/open-networks/.

[23] https://www.ofgem.gov.uk/sites/default/files/docs/2020/07/ed2_ssmc_overview.pdf

[24] Ofgem, DSO Position Paper, at 18.

[25] Ofgem, Distribution System Operation Incentive Governance Document, at 35

Australian Experience. Australia's federal government recently commenced the National Consumer Energy Resources Roadmap process which includes a dedicated stream focused on the development of an integrated set of functions for DSO models.[26] While this initiative has not yet delivered a public report, several years of prior work by Energy Networks Australia[27], the Australian Energy Market Operator (AEMO)[28] and Australia's national science agency CSIRO broadly align with the UK findings above. In addition, as part of Australia's contribution to the Global Power System Transformation (G-PST) initiative, CSIRO has funded several years of applied research examining future grid architectures needed to systems-integrate tens of millions of CER/DER. This work has recognized the critical role of DSOs as integral to decarbonized power systems and ensuring that the supply and demand-sides of the future grid are capable of functioning together in a far more dynamic manner to enable whole-system optimization.[29]

EU Experience. Given the number and diversity of European Union member states and their conventional DSOs, the EU has recognized the critical role of Active DSOs[30] as integral increasingly decarbonized grids and established the EU DSO Entity. While it has not yet formally outlined a definitive set of Active DSO functions, significant effort has advanced to examine potential transformation pathways from conventional DSO functions to more holistic Active DSO models. For example, the Centre on Regulation in Europe (CERRE) reported broadly similar findings to both the UK and Australia in its 2022 report[31] while also mapping three potential stages of transformation: Efficiency Stage; Responsive Stage; and, Active Stage. In this model the third stage involves a new focus on managing DERs in a manner that optimizes their use and maximizes the grid's overall contribution to climate goals and decarbonization.

5.2 Analytical Approach to DSO Functions

Guided by the direction and vision outlined by the Resolve and informed by international precedent, the sections that follow develop the core DSO functions in greater detail. The report examines whether there is conceptual evidence that the DSO can be functionally designed to integrate and utilize DERs from two perspectives:

- **DSO Function Objectives ("What"):** The objective of each function in relation to each other regarding the integration and utilization of DERs.

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[26] national-consumer-energy-resources-roadmap.pdf Note: Australia uses the term "Consumer Energy Resources" or "CERs" to reflect the fact that many of these distributed resources are deployed by electricity consumers on their premises.

[27] https://www.energynetworks.com.au/projects/electricity-network-transformation-roadmap/

[28] https://www.energynetworks.com.au/projects/open-energy-networks/

[29] https://www.csiro.au/-/media/EF/Files/GPST-Roadmap/Final-Reports/Topic-7-GPST-Stage-2.pdf

[30] As noted earlier the term Distribution System Operator (DSO) is used generically of conventional distribution utilities in the EU. The term Active DSO tends to be employed to describe utilities that are transforming to actively integrated and coordinate DER in a high-DER context and is therefore synonymous with how the term DSO is used elsewhere.

[31] https://cerre.eu/publications/the-active-distribution-system-operator-dso/

- **DSO Function Design Elements ("How"):** The supporting design principles and capabilities needed to support the objective of each function.

5.3 DSO Function Objectives

Each of these functions has been historically performed by the distribution utilities and other entities. A key premise for considering a DSO is that these functions should be enhanced to better support the integration and utilization of DERs. To understand how these functions could be enhanced effectively, it is important to acknowledge the objectives of these functions in the existing electricity system and how they would need to evolve to support a high-DER system.

Traditionally, the electric distribution system was designed primarily to deliver affordable, reliable electricity to end consumers from the transmission and bulk power system powered by large, utility-scale generation. These traditional system objectives still apply to a high-DER grid. However, they will need to be expanded to support the more diverse and complex set of needs presented by a 21st-century electricity system that integrates growing amounts of participating DERs, accommodates bidirectional power flows, and unlocks the greatest benefits of DERs. The DSO concept recognizes the need to enhance traditional distribution utility functions for a high-DER future system. This will require redefining existing functions' objectives and defining new ones.

Below, we offer objectives for each of the DSO core functions, informed, in part, by international precedent as appropriate.

System Operations

The objective of system operations is to maintain safe, reliable and efficient real-time operation of the distribution network for the dual purpose of: (1) ensuring continuous supply of electricity to end-use customers, and (2) facilitating the participation of DERs to provide operational services to the distribution system and wholesale-market services to the ISO or bulk system operator.

The traditional objective of distribution system operation has been to maintain reliable, safe, and efficient delivery of electricity service to end-use customers, in a context where electricity supply has come almost entirely from the bulk transmission system and customer participation in grid operation has been limited to demand response services. For a future system with significant amounts of energy supply connected to distribution and expanded participation of customers and diverse DERs in system operation, the objective statement must expand to include integration of DERs into the system and facilitating their participation in a manner that unlocks and utilizes their maximum potential benefits.

How does this contribute to integrating and utilizing DERs?

This process ensures that DERs can be dispatched to take full advantage of their flexibility in operations as identified in the planning process. DERs can be dispatched both to cost-effectively integrate them utilizing existing system capacity (i.e., flexible interconnection) and to provide distribution grid services.

UK experience. In its guidance regarding DSO system operations, Ofgem states the DNOs' network operation must reflect distributed energy resources' (DER) ability to cause and alleviate network constraints, and the need for sufficient network visibility and efficient dispatch decisions.[32] UKPN states that system operations must ensure the use of flexibility services to support all network and system needs where they deliver value for consumers, leveraging real-time optimization to deliver the highest levels of network utilization and network access for users.[33]

Integrated System Planning

The objectives of Integrated system planning are to: (1) ensure that there is sufficient generation and system infrastructure capacity to serve customers reliably, safely and affordably; (2) ensure there is sufficient network capacity to integrate large amounts of DERs; (3) consider all solution options, such as competitive DER solutions and innovative uses of existing assets (e.g., flexible interconnection and grid enhancing technologies), to meet system upgrade needs; and, (4) support integration of distribution-connected renewable generation and storage resources to contribute to Maine's clean energy policy goals.

The precedents from the UK, Europe, and Australia provide a reasonable basis for using the planning process to unlock the benefits of DER. This report suggests, however, that integrated system planning in the Maine context could go further. These other jurisdictions emphasize the use of DER services by the DSO to better utilize distribution system capacity to integrate larger amounts of DERs, to support bulk-system operation with higher amounts of renewable generation. In addition to these applications of DERs, this report suggests that Maine could utilize distribution-connected renewable generation to provide a significant quantity of renewable energy to accelerate the state's clean energy targets. A 2016 study by the National Renewable Energy Laboratory (NREL) of the national potential of solar generation deployed on roofs of buildings of all sizes estimated that Maine could provide 60 percent of its annual electricity sales from rooftop solar PV.[34] It is with this expanded potential in mind that this report offers the above objective statement for the integrated system planning function.

How does this contribute to integrating and utilizing DERs?

This process ensures that DERs can be integrated in a timely manner by planning for the right investments to enable new capacity and leveraging innovative approaches to utilize existing system capacity. Moreover, it serves as the foundation to utilize DERs by identifying the distribution system constraints that could be addressed through a competitive DER market for distribution grid services. These constraints can then be used to procure services via the DER market administration

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[32] https://www.ofgem.gov.uk/sites/default/files/docs/2020/07/ed2_ssmc_overview.pdf

[33] UK Power Networks Business Plan 2023-2028, at 5. https://d16qag4vfpk8c6.cloudfront.net/app/uploads/2021/12/Appendix-18-Our-DSO-Strategy.pdf

[34] The NREL study examined solar generation potential of all sizes of buildings, with the strategy of exploiting the maximum solar potential of each roof rather than limiting solar installation size to just meet the energy needs of the building itself. The study estimated that the U.S. as a whole could meet 39 percent of its annual electricity sales in this manner. NREL (2016) "Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment"; https://www.nrel.gov/docs/fy16osti/65298.pdf.

function and ultimately dispatch DERs to address these constraints via the system operations function.

UK experience. In its guidance regarding DSO system planning, Ofgem says planning and network development should plan efficiently in the context of uncertainty, taking account of the whole electricity system including transparent, robust decision-making processes that fairly value flexibility.[35] UK Power Networks (UKPN), one of UK's DSOs outlines its objective for planning to enable the rapid uptake of DER, through maximizing the use of existing capacity, wherever possible, and the timely release of additional capacity via an open, transparent, and competitive network development approach and a whole system planning framework that considers all solution options on a level playing field.[36] This is consistent with other UK DSOs' defined planning objectives, including SP Energy Networks[37], National Grid, Electricity North West[38] and Scottish & Southern Electricity Networks[39].

DER Market Administration

The objective of administering DER markets is to establish and operate a distribution-level market platform and market mechanisms to enable DERs to participate in economic transactions for energy and grid services in coordination with wholesale markets to ensure efficient whole-system outcomes and support reliable whole-system performance.

The UK, Europe, and Australia initiatives on markets and other economic mechanisms for DERs are focusing mainly on grid-supporting services such as load flexibility and other forms of load management. These jurisdictions generally define DERs as various asset types that are deployed behind-the-meter (BTM) on customer premises.[40] As discussed earlier, this report considers a larger definition of DERs that includes front-of-the-meter assets such as solar + storage hybrid generators that can export energy to the system in addition to ancillary grid services.[41] To realize the greatest value from this larger category of DERs, the DSO market administration function for Maine should also include opportunities for front-of-meter resources to participate in distribution-level market transactions.

How does this contribute to integrating and utilizing DERs?

Market mechanisms for participating DERs to transact for energy and grid services can provide an efficient and reliable means to unlock the greatest benefits of DER performance capabilities. Well-

[35] Ofgem RIIO-ED2 Methodology Consultation: Overview, at 58

[36] UK Power Networks Business Plan 2023-2028, at 5. https://d16qag4vfpk8c6.cloudfront.net/app/uploads/2021/12/Appendix-18-Our-DSO-Strategy.pdf

[37] https://www.spenergynetworks.co.uk/userfiles/file/SPEN%20RIIO-ED2%20Final%20Business%20Plan%20-%201st%20December%202021%20-%20FINAL.pdf

[38] https://www.enwl.co.uk/globalassets/about-us/regulatory-information/riio2/december-final-submission/our-plan-to-lead-the-north-west-to-net-zero-2023-28.pdf

[39] https://ssenfuture.co.uk/wp-content/uploads/2021/12/24645-SSEN-ED2-Final-Business-Plan-Website.pdf

[40] Australia uses the term "consumer energy resources" or "CERs" to reflect the fact that the assets in question are deployed by electricity consumers on their premises.

[41] See earlier footnote regarding 2016 NREL study on the technical potential of rooftop solar to supply substantial shares of annual electricity sales in U.S. states.

designed market mechanisms can enable participating DERs to be compensated for the value they provide to the system.

Lessons Learned from Other Jurisdictions

UK experience. In its guidance regarding DSO market development, Ofgem states the DNOs must actively develop markets to enable and appropriately reward DER to provide services, including distribution non-frequency ancillary services (DSO ancillary services), to efficiently manage their network. The DNOs must also coordinate the development of these markets, their procurement and the dispatch of flexibility with the ESO to ensure efficient whole systems outcomes.[42]

UKPN states their objective is to create new markets for networks flexibility services at the distribution level, to procure more of our needs closer to real-time, and to ensure integration of markets so that they can easily sell their flexibility where it is most valued in the whole system and allow DER access to new potential revenue streams and products and services, as well as to ensure we can meet the flexibility needs of the DSO.[43]

Data Access & Management

The objective of data access and management is to ensure that all grid actors, including DSO, ISO and DER market participants, have sufficient data and visibility to perform their functional responsibilities and facilitate the efficient and reliable deployment, operation and utilization of DERs.

How does this contribute to integrating and utilizing DERs?

The traditional electricity system primarily consisted of utility-owned assets, which were deployed and operated across a single entity to manage the distribution system. A high-DER system introduces a significant number of market participants, independent of the DSO, who deploy and operate assets on the distribution system. As such, communication is needed between the DSO and these market participants to ensure they are integrated and utilized in a reliable manner. This communication includes the exchange of data. The DSO needs to both share and receive data to effectively perform each DSO function. Market participants need different types of data to site, interconnect, operate and participate in markets using their DER assets. Moreover, the DSO needs visibility into these market participants to inform planning, operations and administering of DER markets. Thus, bidirectional data sharing is needed between the DSO and market participants for each DSO function.

Lessons Learned from Other Jurisdictions

UK experience. In its guidance regarding DSO data access, Ofgem emphasized data exchange as a key enabler for DSOs[44] and the interoperability, visibility and accessibility of data across the energy industry.[45] Specifically, Ofgem emphasized the importance of making network data visible

[42] Ofgem RIIO-ED2 Methodology Consultation: Overview, at 53. https://www.ofgem.gov.uk/sites/default/files/docs/2020/07/ed2_ssmc_overview.pdf.

[43] UK Power Networks Business Plan 2023-2028, at 7. https://d16qag4vfpk8c6.cloudfront.net/app/uploads/2021/12/Appendix-18-Our-DSO-Strategy.pdf.

[44] Ofgem, DSO Position Paper, at 18.

[45] Ofgem, DSO Position Paper, at 5.

and sharing this in an open, interoperable way, to better support the emerging and existing markets and to embed whole system outcomes.[46] This would include sharing network information with the Electricity System Operator, network users and other interested parties. Ofgem also emphasizes the need for DSOs to collect sufficient information on DER characteristics and parameters,[47] among other types of DER data.

Transmission & Distribution (T&D) Coordination

The objective of T&D coordination is to ensure sufficient coordination of planning, operation, and market administration between the distribution and transmission systems so that DERs can be utilized as a significant source of clean energy supply and cost-effective grid services across the entire system. In the subsequent sections, T&D coordination is discussed in the context of each of the three core DSO functions.

T&D coordination was relatively straightforward in the traditional 20th-century power system. There was a "supply side" on the bulk transmission system where virtually all the generation was located. And there was a "demand side" comprised of electricity end-users who consumed energy with little or no regard for impacts on the grid and limited opportunities to participate actively in supporting system performance. The distribution system only had to deliver energy one way, from the supply side to the demand side. While this was always a technically demanding role, it was well-defined and predictable. The introduction of large quantities of DERs as customer-sited assets, as supply resources, and as active system participants requires expanding the distribution system role and rethinking the relationship between distribution and the bulk power system.

The evidence from the UK, Europe, and Australia confirms that new T&D coordination procedures are required in all three core areas – operation, markets, and planning – to ensure reliable and efficient whole-system performance as DER volumes increase.

The evidence supporting the definition of each of the core functions above emphasizes strongly embedded whole system outcomes across the functioning of the DSO. T&D coordination across the three core functions is the means to do this.

How does this contribute to integrating and utilizing DERs?

This process ensures there is a strong economic business case for market participants to integrate DERs because T&D coordination will ensure that DER customers can fully utilize their systems for all the benefits they can provide across the system and access to new potential revenue streams and products and services.

[46] Ofgem, DSO Position Paper, at 18.

[47] Ofgem, Distribution System Operation Incentive Governance Document, at 35

5.4 System Operations

Objective: *To maintain safe, reliable, and efficient real-time operation of the distribution network for the dual purpose of: (1) ensuring continuous supply of electricity to end-use customers, and (2) facilitating the participation of DERs to provide operational services to the distribution system and wholesale-market services to the ISO or bulk system operator.*

Now that we understand the DSO Function Objectives ("What") for system operations, we can evaluate the DSO Function Design Elements ("How"). The following principles, capabilities and processes were identified based on international precedent and United States specific trends as key DSO design elements to support the objective of DSO-driven Integrated System Planning. We will elaborate on each design element in the subsequent sections.

Key Design Elements

Key Principles:

- ♦ Interconnection (DER Integration) + Grid Dispatch (DER Utilization)
- ♦ Differentiated Operational Approach

Key Capabilities & Processes:

- ♦ Flexible Connections
- ♦ Grid Services
- ♦ Operational Network Visibility
- ♦ DER Orchestration Plan
- ♦ T&D Coordination

5.4.1 Key Principles

5.4.1.1 Core Components: Integration and Utilization

There are two core components of system operations related to DERs:

Interconnection (Integration): Process by which DERs are physically connected to the distribution system in a way that allows for their day-to-day operation in line with customer and/or DER operator expectations while being designed to stay within the operational constraints of the distribution system. In other jurisdictions, such as the UK, flexible connections have been a top priority and core operational function for DSOs.

Dispatch (Utilization): Process by which DERs are dispatched to provide energy and grid services across the distribution and bulk power system electricity system.

Processes and the corresponding capabilities need to be designed to enable each of these operational approaches as described below.

5.4.1.2 A Differentiated DER Operational Approach

Integrating and utilizing DERs is not a one-size fits all approach. Customers and developers deploy DERs for different purposes, each of which have different operating characteristics the DSO must design system operations to accommodate. There are four operating modes the DSO will need to accommodate to realize the greatest total value in a high-DER future:

Interconnection

Static Connections

DERs connected through traditional agreements where they are able to export or import at their full nameplate capacity with no curtailments except under emergency conditions.

Dynamic Connections

DERs connected through flexible connection agreements in which the customer and/or DER operator agrees to dynamically curtail their systems in response to instructions based on day-ahead forecasts or real-time system conditions.

Grid Services

Non-participating DERs

DERs deployed by end-use customers to provide their needs for electricity or other services. Rooftop solar PV, battery storage, electric vehicles and charging equipment, etc., typically operated by the customers to meet their needs without providing services to the greater power system. Their behavior can be shaped somewhat by rate designs, but these resources primarily serve the purpose of meeting customer needs as opposed to providing grid services. Their behavior will be largely statistical rather than explicit fulfillment of a service obligation to the grid.

Distribution Market DERs

DERs/DERAs providing distribution system services and participating in local energy transactions. DER value extends beyond the benefits to end-use customer adopters. In a well-functioning high-DER system, DERs can support reliable distribution grid operation, expand hosting capacity to increase solar PV deployment, and avoid or defer distribution infrastructure upgrades. The DSO is the counterparty to the DER/DERA for such services. DERs can also be local supply resources to serve local customers without impacting the bulk system, reducing the need for transmission-connected generation and transmission upgrades. In this case the DSO would be the facilitator of local energy markets or bilateral transactions.

Wholesale Market DERs

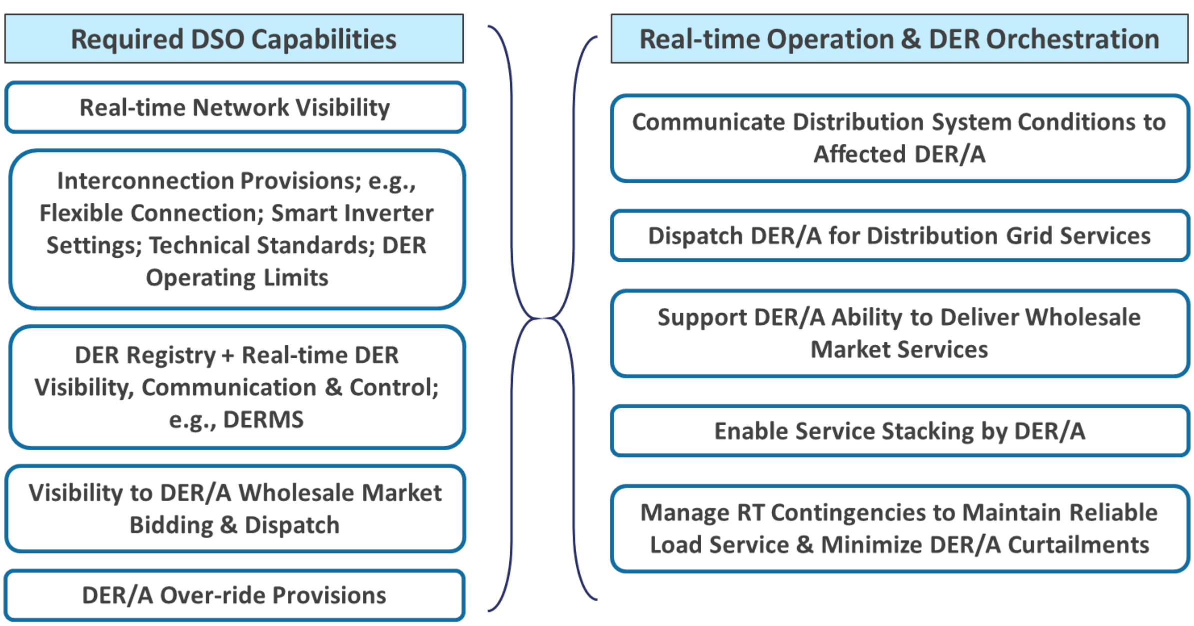
DERs or DER aggregations (DERAs) participating in the wholesale markets of ISO-NE or providing transmission-level services to the NMISA/NBP balancing authority. As a result of FERC Order 2222, the ISOs/RTOs and their participating states and utilities are pursuing this mode of DER/DERA participation. Although these services are typically two-party transactions between the DER/DERA and the ISO/BA, their performance requires the use of and will impact the distribution system, which then requires DSO involvement. For DER/DERA participation to be successful, the ISO/BA must be confident that the DER/DERA will deliver the services it procures and dispatches; the DER owner or aggregator must be confident that it can deliver its services over the distribution system with minimal risk of curtailment by the DSO; and the DSO must be able to maintain reliable operation of its system.

Wholesale + Distribution Market DERs

DERs/DERAs providing both (ii) and (iii) under “dual participation” or “service stacking” provisions.

5.4.2 Key Capabilities & Processes

It is necessary first to define the processes by which each operational approach will be implemented before defining capabilities. This is because each operational approach, interconnection, and grid services dispatch will ultimately drive the requirements for the capabilities. Moreover, both operational approaches rely on the same capabilities - visibility and control of DERs and therefore, it is important to scope these upfront to ensure a comprehensive and scalable set of technical solutions can be deployed and to avoid duplicative unnecessary investments.



5.4.2.1 Flexible Connections

This report will primarily focus on interconnection from a flexible connections perspective as this approach has played a pivotal role in DSOs better integrating DERs. Flexible connection is the natural evolution from traditional interconnection processes and a foundational strategy to more rapidly and cost-effectively integrate more DERs using existing system capacity. Flexible connections have emerged as a business as usual (BAU) approach for DSOs across the world including UKPN[48] and National Grid[49] in the United Kingdom, and DNOs across Australia.[50] Moreover, flexible connections are gaining traction in the United States as well with demonstrations, mandates and investigations including in Illinois, Massachusetts, New York, California, Colorado and Maryland. A DSO should develop and scale flexible connection options via a comprehensive approach as described below.

Flexible connection options should be available for load and generation facilities

Flexible connections are applicable to both load and generation facilities and thus options should be offered for both. Specifically, flexible connections can be valuable for solar, solar + storage, standalone storage and EV charging facilities.

A diverse set of flexible connection options may be needed to meet a diverse set of DER needs

DER operators may have different operational needs and thus need different types of flexible connection options. For example, some DER operators may not have the sophistication or flexibility to be actively monitored and curtailed in real-time. National Grid UK offers three types of flexible connections:

<u>Timed Connections</u>: Based on time of day, day of week, or seasonal factors. By understanding the conditions that would adversely affect the network and limiting the output during certain time periods, the connection can be permitted without the requirement for extensive reinforcement.

<u>Export Limitation Schemes</u>: These schemes measure the apparent power at the installation's exit point and use this information to restrict generation output and/or balance customer demand to prevent the agreed upon export capacity from being exceeded. The equipment required for export limiting is customer-owned and provided to minimum standards.

<u>Load Managed Connections</u>: These make use of real-time SCADA based monitoring and analysis to determine the ability of the network to accommodate the customer's facility. When network

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[48] UK Power Networks Flexible Connection Offerings. https://www.ukpowernetworks.co.uk/new-electricity-connections/distributed-energy-resources-der-generation/flexible-connections.

[49] National Grid UK Flexible Connection Offerings. https://www.nationalgrid.co.uk/downloads-view-reciteme/540250#:~:text=Flexible%20Connections%20are%20connection%20arrangements,agreed%20principles%20of%20available%20capacity.

[50] Australia Renewable Energy Agency, Dynamic Operating Envelopes Workstream: Outcome Report, at 27, March 2022. https://arena.gov.au/assets/2022/03/dynamic-operating-envelope-working-group-outcomes-report.pdf

conditions are such that the full load cannot be accommodated, a constraint signal is sent via a Connection Control Panel, with connections affecting the same network constraints curtailed. Load management may be implemented with an Active Network Management (ANM) system or a Soft Intertrip Scheme.[51]

For the purposes of this report, we will focus the latter two options and will refer to export limitation schemes as *static flexible connections* and load managed connections as *dynamic flexible connections*. We elaborate on each approach in the subsequent sections.

Flexible connection options should include dynamic flexible connections

Dynamic, flexible connections represent a set of DER control strategies to integrate more DER capacity than would traditionally be permitted, provided these DERs are managed in real or near real-time to curtail their output during peak periods. This approach has also been referred to as Active Network Management, Active Resource Integration, and Load Managed Connections. This approach relies on the concept of dynamic hosting capacity, which asserts that the true hosting capacity of the system is time-varying in nature and thus greater than conventional limits, which are typically a single value based on a worst-case scenario.

Flexible Interconnections allow participating DER to utilize the real-time hosting capacity of the portion of the grid they are interconnected to, referred to as "Dynamic Hosting Capacity," by providing direct feedback from the constrained point(s) on the grid to a centralized control system which can automatically limit the maximum output of the DER site if necessary to prevent the grid constraint from being violated. Flexible Interconnections can enable the interconnection of more DER capacity and the generation of more renewable energy without requiring expensive and time-consuming Static Capacity grid upgrades.[52]

The illustration in Figure 2 below shows a conventional interconnection example. A traditional hosting capacity analysis establishes a Conventional Limit (green-dashed line) based on hosting capacity criteria at both the substation and feeder levels. The output waveform of DER (blue curve) serves as an illustration of potential daily PV production, fluctuating within the confines of the installed DER Capacity envelope. For conventional interconnections, the output of a DER must not exceed the conventional limit of hosting capacity. The dynamic hosting capacity (black-dashed curve) considers the real-time behavior of connected DER, load, and grid devices. As a result, the dynamic hosting capacity varies over time due to the loading presented in time-series data.[53] By

[51] National Grid UK Flexible Connection Options, https://www.nationalgrid.co.uk/downloads-view-reciteme/540250#:~:text=Flexible%20Connections%20are%20connection%20arrangements,agreed%20principles%20of%20available%20capacity.

[52] NYSEG Flexible Interconnect Capacity Solution (FICS), Intermediate Report, August, 12, 2024. https://www.nyseg.com/w/nyseg-and-rg-e-demonstrate-ability-to-add-renewable-energy-onto-grid-with-flexible-interconnections

[53] Commonwealth Edison Refiled Grid Plan, Chapter 5, at 50-55, March 13, 2024. https://www.icc.illinois.gov/docket/P2022-0486/documents/348096/files/607970.pdf

controlling DERs based on a dynamic hosting capacity curve, more DER capacity can be connected within the current constraints of the system.

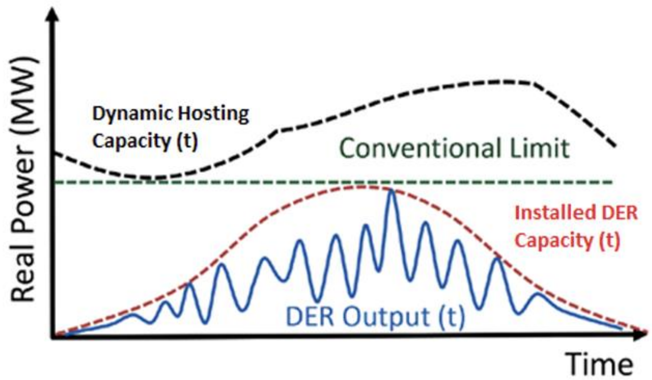


Figure 2 Conventional Interconnection[54]

The illustration in Figure 3 below shows a flexible interconnection where DER operation is managed within the dynamic limit. The orange shaded area represents the PV/solar production that will be curtailed when it exceeds the dynamic hosting capacity. This figure depicting flexible interconnection shows the ability to integrate additional DER beyond the conventional limit through increased monitoring and controls of the DER, with targeted curtailment triggered by certain DER output and load and system conditions. Such flexible interconnection operation, could avoid costly distribution system upgrades associated with the interconnection of DER.[55]

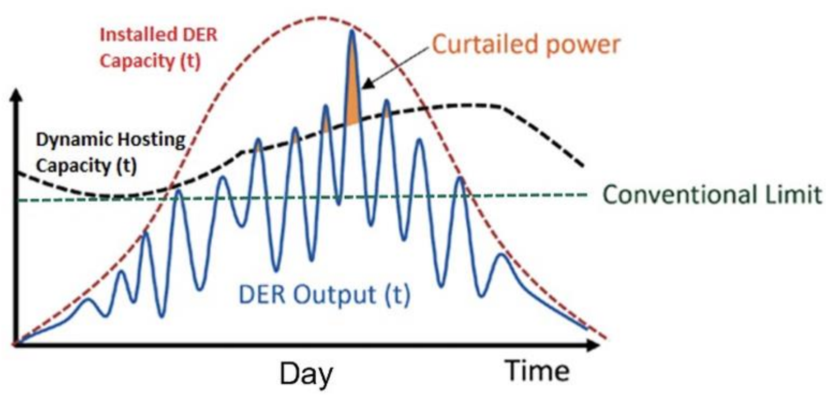


Figure 3 Flexible Interconnection[56]

To provide a real-world example, Commonwealth Edison (ComEd) in Illinois demonstrated dynamic, flexible connections in 2021 to enable the connection of nearly 9 MW of additional DER generation to the grid on a transformer that would have been constrained under conventional limits. The use

[54] Electric Power Research Institute, Understanding Flexible Interconnection. https://www.epri.com/research/products/000000003002014475.

[55] Commonwealth Edison Refiled Grid Plan, Chapter 5, at 50-55. March 13, 2024. https://www.icc.illinois.gov/docket/P2022-0486/documents/348096/files/607970.pdf

[56] Electric Power Research Institute, Understanding Flexible Interconnection. https://www.epri.com/research/products/000000003002014475.

of DERMS to implement dynamic flexible connections will result in a notable 22% increase in PV generation without causing adverse thermal issues on the substation transformer.[57] Since then, ComEd has committed to scale this offering, expecting to enable a minimum of 240 MW of DERs, with an average of 3 MW per site.[58]

Two different DER control/orchestration approaches have been leveraged across the world to enable dynamic flexible connections: (1) utility control, and (2) DER operator control. The United Kingdom and several utilities across the United States have, thus far, relied on direct control via a Distributed Energy Resource Management System (DERMS). A DERMS is a centralized utility-owned software system that would directly connect to a controller (e.g., smart inverter) at the DER facility and send curtailment signals based on real-time conditions.

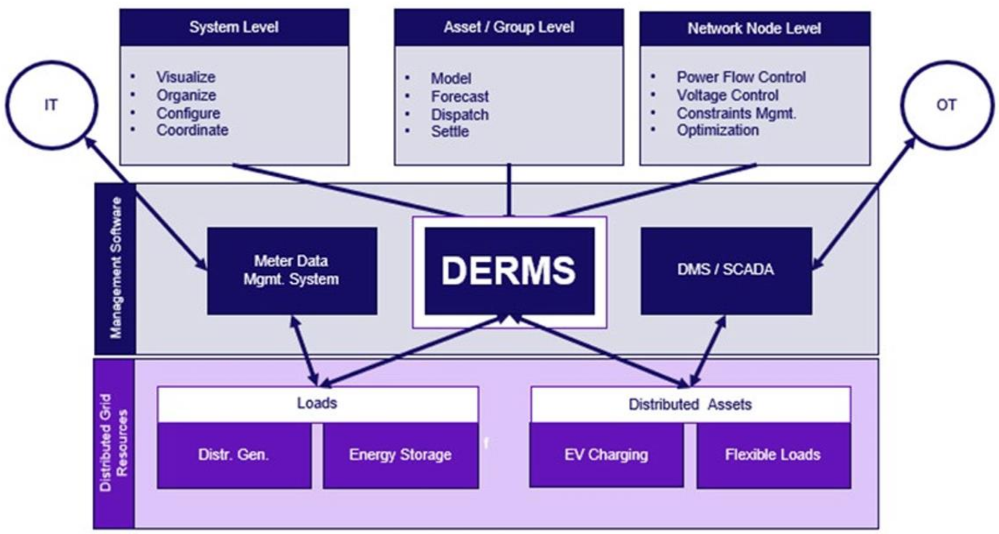


Figure 4 Example DERMS Direct Control Flexible Connection Architecture

In contrast, Australian utilities have relied on DER operators to control and adjust their facilities based on the dynamic hosting capacity of the system. Australia refers to the operating parameters of dynamic hosting capacity a DER must operate within as dynamic operating envelopes (DOEs). The distribution utility calculates the operating envelope, the envelopes are communicated to customer devices, and the customer devices respond to the envelope. This could include communication with individual customers or aggregators. One of the driving factors behind the ability to implement this approach is that Australia is moving towards a common smart inverter and communications standards, CSIP-AUS/2030.5, which provides increased confidence that these devices will consistently operate within the provided operating envelopes[59] and thus can be

[57] Commonwealth Edison Refiled Grid Plan, Chapter 5, at 50-55. https://www.icc.illinois.gov/docket/P2022-0486/documents/348096/files/607970.pdf

[58] ComEd Refiled Grid Plan, Ex. 104.0 RGP, at 59. https://www.icc.illinois.gov/docket/P2022-0486/documents/352005/files/615777.pdf.

[59] Australia Renewable Energy Agency, Dynamic Operating Envelopes Workstream: Outcome Report, at 21-22, March 2022. https://arena.gov.au/assets/2022/03/dynamic-operating-envelope-working-group-outcomes-report.pdf

trusted to be integrated into system operations. Having a common set of standards will help streamline this process and make DSOs comfortable with this which we discuss as part of the DER Orchestration plan.

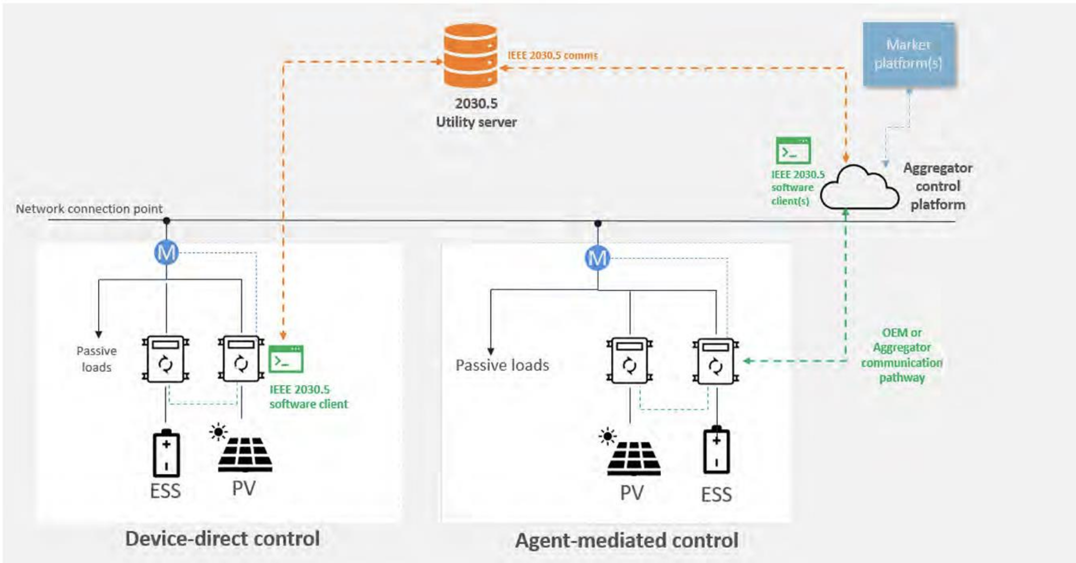


Figure 5 Example DER Operator Control Architecture[60]

South Australia (SA) Power Networks is in the process of scaling dynamic operating envelopes across its network, requiring all new solar systems to be compatible with flexible exports with the expectation by the end of 2024 that flexible exports will be the *default connection arrangement* for new solar customers connecting anywhere on the network.[61]

[60] Australia Renewable Energy Agency, Dynamic Operating Envelopes Workstream: Outcome Report, at 25, March 2022. https://arena.gov.au/assets/2022/03/dynamic-operating-envelope-working-group-outcomes-report.pdf

[61] SA Power Networks, CER Integration Strategy, 2025-2030 Regulatory Proposal, January 2024.

Figure 6 SA Power Networks Flexible Export Offering[62]

Flexible connection options should include static flexible connections

DSOs should also offer static flexible connection options for DER operators who are unable to participate in dynamic options. Static flexible connections allow a DER operator to build their entire facility but agree to only export or import a portion of their total nameplate capacity until system upgrades are completed. This option is also known as ramped connections, export/import limitation schemes and automated load management.

This offering would be appealing to DER operators who either may not have sophisticated enough equipment to integrate with systems like a DERMS or their specific operational objectives would not align with real-time curtailments. This use case is particularly applicable to EV fleets. For example, an EV fleet may need to charge and utilize their trucks year-round and cannot afford to agree to real-time curtailments as this would jeopardize the operation of their fleets. As shown In the figure below, the EV fleet would build 1.8 MW of EV charging capacity but agree to only import 1.0 MW.

[62] SA Power Networks, CER Integration Strategy, 2025-2030 Regulatory Proposal, January 2024.

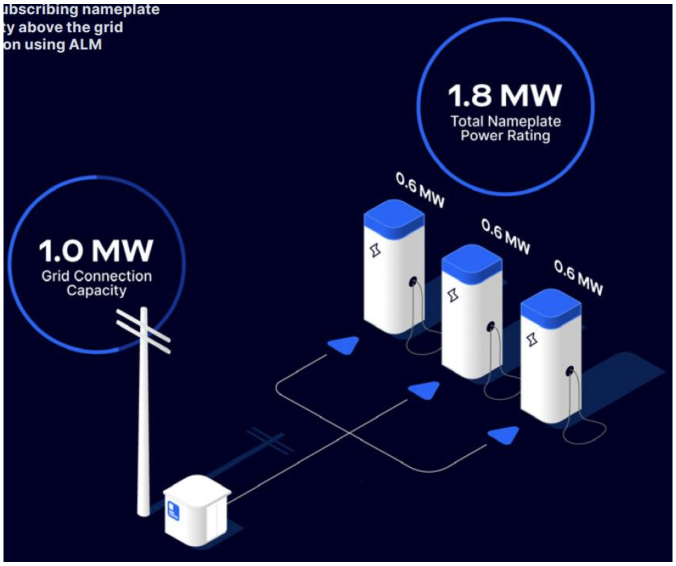


Figure 7 Static Flexible Connection[63]

DER operator control is the primary DER orchestration approach used for static flexible connections. The site's software, which can include a charge management system (CMS), will be configured to a setpoint (e.g., 1.0 MW in Figure 7). The CMS will allow unlimited charging until the site's actual load approaches the set point. If the actual load approaches the set point, then the ALM system will reduce the charging power to maintain the load below the set point.[64]

UKPN currently offers static flexible connections as a BAU offering.[65] Southern California Edison (SCE) also recently established a two-year customer-side, third party owned Automated Load Control Management Systems (LCMS) Pilot to support customers that must wait to receive service connection until needed grid capacity upgrades are complete by providing them the option to receive service based on currently available capacity.[66] ComEd has also committed to develop a flexible interconnection plan which includes the evaluation of export (i.e., generation) and import (i.e., load) limitation schemes.[67]

Developing and scaling flexible connections requires the refinement of key operational details

Developing the technical approach by which different flexible connection options will be implemented is only one of many components required to provide scalable, business as usual

[63] Mobility House, Automated Load Management Whitepaper. https://www.mobilityhouse.com/usa_en/knowledge-center/whitepaper/alm-guide-fleet-charging

[64] Mobility House, Automated Load Management Whitepaper. https://www.mobilityhouse.com/usa_en/knowledge-center/whitepaper/alm-guide-fleet-charging

[65] UKPN Ramped Capacity Connection. https://media.umbraco.io/uk-power-networks/zfsb3aqg/ramped-capacity-connection-guide.pdf

[66] California Public Utilities Commission (CPUC), Advice Letter 5138-E and 5138-E-A, January 16, 2023.

[67] ComEd and Joint Non-Governmental Organizations (JNGO) Memorandum of Understanding, at 4. https://www.icc.illinois.gov/docket/P2022-0486/documents/350981/files/613798.pdf.

offerings. In particular, processes need to be developed to balance ensuring the DER operator has certainty the flexible connections will meet their operating parameters and provide certainty to financiers while giving the DSO operational flexibility to maintain reliability during unanticipated adverse system conditions. The following describes several other components that must be considered:

*Flexible Connection Initiation & Request***:** Processes need to be developed for who initiates the flexible connection request. This could include the DSO proactively making these options available via the energization or interconnection process and/or the DER operator could initiate the request.

Study Analysis: Processes need to be developed for what data is required from the DER developer to conduct a study and what outputs are needed from the DSO's interconnection study. The outputs of the study will be critical to informing whether DER developer's operational needs align with any anticipated curtailments and to have sufficient certainty to finance the project. This is particularly applicable to dynamic flexible connections as this will involve curtailments.

Contractual Obligations: Processes are needed for memorializing flexible connections into legal enforceable agreements so that DER developers have certainty they can meet their operational needs and to improve the chances of successfully financing projects.

Override & Compensation Mechanisms: Processes are needed to define conditions in which the DSO can override the flexible connection agreements to maintain the reliability of the system. Moreover, compensation mechanisms need to be established to compensate DER developers for curtailments greater than the agreed to amount in the contractual agreements to provide certainty of financial returns for financing partners.

Tariff Modifications: Understanding any modifications needed to tariffs to operationalize the components described above.

5.4.2.2 Dispatch Grid Services

Defining DER grid services

The first step in dispatching grid services is to identify and define the different grid services that DERs can provide followed by detailed requirements to operationalize each grid service - this section will focus on the former. Several different frameworks exist for the categorization of grid services and should be adapted to Maine's specific needs.

The Pacific Northwest National Laboratory (PNNL) has outlined a useful set of common grid services terms and definitions that may serve as a foundation to inform Maine-specific grid service definitions.

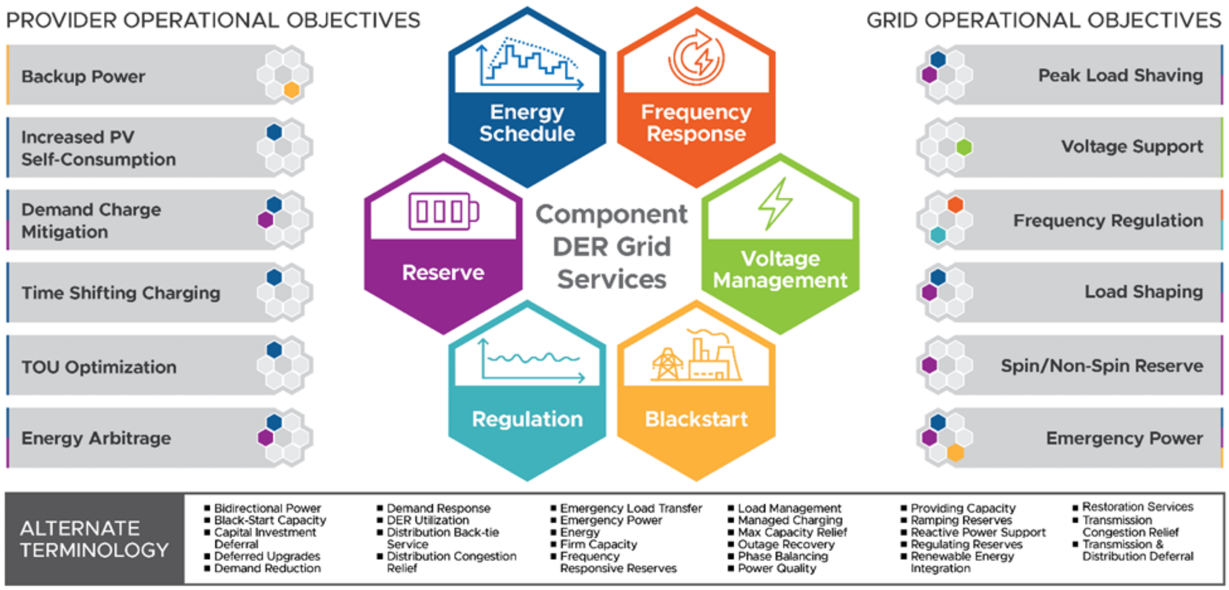


Figure 8 Categories of DER Grid Services[68]

Energy Scheduling: A scheduled production or consumption of energy at an electrical location over a committed period. Today's distribution-level energy service programs tend to be price-reactive mechanisms like time-of-use rates, or critical-peak pricing rates, or various forms of dynamic pricing programs. In transactive energy systems, DER facilities develop energy schedules to establish their consumption or production as part of their interaction with a local energy market. The distribution-level grid service is similar to the wholesale energy service except that distribution constraints are handled differently than the use of locational marginal prices in transmission-level markets.

Reserve: Reserves a specified capacity to produce or consume energy at an electrical location when called upon over a committed period. The requestor of service may call upon the resource to produce or consume this energy by signaling the service provider to operate based on the reserved energy amount. Typically, multiple reserve products can be offered based on how quickly the resource can respond to notification. Spinning and non-spinning/supplemental reserves are common monickers for resources that are available relatively rapidly and those that may take longer to respond, respectively. Reserve service can participate in both a day ahead and hourly/real-time market. A distribution-level program that arranges a reserve of energy from DERs and engages them based on a call or signal would also fall into the category of reserve service. Today, aggregators typically control customer equipment directly; however, future arrangements could be with a reserve service agreement that delegates the customer site to manage its own equipment to maintain reserves and respond to a reserve signal when called upon.
Regulation: The resource continuously provides an increase or decrease in real power from an electrical location (point of interconnection) over a specified scheduled period against a predefined

[68] PNNL (2023), "Common Grid Services Terms and Definitions Report.

real-power basepoint following a service requestor's signal. Regulation is a reliability service that corrects for short-term changes in electricity usage that may affect the stability of the power system.

Frequency Response: The resource must respond to a change in system frequency nearly instantaneously by consuming or producing power over a committed period. This is typically used to moderate a sudden change in frequency and requires local detection of frequency deviation and autonomous response.

Blackstart: The resource must be able to energize or remain available without grid electrical supply to energize part of the electric system over a committed period. This service is part of a restoration plan used following grid blackouts. Historically it has been procured on a cost-of service basis.

Utilization of DER grid services can evolve as adoption levels mature

A maturity roadmap can help to inform the dispatch of DER grid services over time and as adoption levels increase, such that these services can be utilized where possible today with less sophisticated approaches as the DSO develops more sophisticated capabilities to leverage a full suite of advanced grid services.

Different grid services can have different levels of sophistication. For example, in the UK, flexibility services are scheduled forward of delivery based on a longer-term forecast on a year/month ahead basis, often at the procurement stage where the DER is contracted to provide its energy for specific time periods. The majority of dispatch scheduling is currently conducted pre-fault, but UKPN is working towards developing capabilities to dispatch post-fault and support restoration.[69]

Specifically, each DER grid service should be clearly defined:

- What are the availability and performance requirements of the provider of the service?
- Through what process will potential providers be pre-qualified to provide the service?
- How are availability and performance measured and compensated? What are the consequences to the provider of deficient availability or performance?
- Through what mechanism will the DSO procure the service?
- What capabilities are needed to leverage this grid service from both the DSO and DER operator perspective?
- Are there different levels of sophistication for utilizing each grid service?
- What are the existing capabilities of the DSO and DER operators today?
- What grid services could be utilized today? What levels of sophistication could be enabled for each grid today?

[69] UKPN, RIIO-ED2 Business Plan 2023 – 2028, at 50.

Development of a transparent dispatch framework

The dispatch of DERs will not only occur for distribution grid services but flexible connections and wholesale market services. Thus, a framework should be developed to ensure the following:

- The framework is developed in collaboration with DER stakeholders as well as the balancing authority to ensure sufficient coordination
- The framework is designed to ensure DERs can be dispatched in a way that is coordinated with flexible connections and the balancing authority. In the case of dispatches from the ISO or BA, this involves specifying the communication pathway for conveying dispatch instructions. For example, does the ISO issue a dispatch directly to a DER/DERA, or to the DSO for transmission to the DER/DERA? How is the DSO able to identify the need for and issue an instruction to the DER/DERA to over-ride an ISO dispatch?
- The framework is designed to ensure DERs can provide a full value stack of grid services for which they are qualified, across the entire system.

5.4.2.3 Improved Operational Visibility

A prerequisite for DSO operation of a high-DER system is to have an accurate map of the distribution assets comprising the system it operates as well as the locations and technical specifications of DERs connected to the system. These two main components are a "Network Model" and a "DER Registry." These components have both static and dynamic attributes.

	Network Model	**DER Registry**
Static attributes	Computer-based map of all distribution network assets, and their electrical attributes, under normal operating conditions and common alternative configurations	Grid locations and electrical attributes of DERs connected to the distribution system, either directly to a utility circuit or indirectly on premises of an end-use customer.
Dynamic attributes	Current grid conditions that involve deviations from normal operating conditions, e.g., changes to network topology or electrical attributes or the availability of specific network assets and their current states will affect performance.	Current DER conditions that involve deviations from their registered electrical attributes or their availability. This will be particularly important for DERs that participate in distribution-level or bulk system services.

Figure 9 Operational Visibility Framework

Operational visibility on a locational and temporal basis for the secondary system
Similar to integrated system planning, operational visibility is needed for the secondary system on a locational and temporal basis to best integrate and utilize DERs. See Section 5.5 within Integrated System Planning for details on why this is important.

Short-term forecasting for operational planning
Operational planning is the preparation for real-time operation that occurs in the period between a few hours up to several days, weeks, or even a month before the operating hour. It includes scheduling planned maintenance of grid facilities and essential resources, forecasting of load and DER activity, procuring additional grid services from DERs if needed, and committing any demand-side or distribution-side resources that may require advance notification.

As the system becomes more dynamic, longer-term operational forecasts (i.e., weeks, month ahead) will become insufficient for operational purposes as system conditions are changing significantly faster than the frequency at which forecasts are conducted creating the risk of inaccurate operational forecasts and thus suboptimal system operations.

Day-ahead short-term operational forecasting is emerging as an optimal frequency for conducting supporting flexible connections. SA Power Networks publishes day-ahead forecasts on a five-minute basis to inform dynamic operating envelopes for solar facilities participating in flexible connections.[70] UKPN also leverages a day-ahead operational planning approach.[71] US-based distribution utilities, including both National Grid[72] and Eversource in Massachusetts have also proposed investing in short-term forecasting capabilities via investments in a Distributed Energy Resource Management Systems (DERMS). Specifically, Eversource proposes to build a near term forecasting capability in system operations that will predict load and generation on the distribution system in the day ahead to week ahead time frame to inform operational planning.[73]

Real-time monitoring of the system and DERs
Operational planning requires more real-time visibility of both the system and DERs operating on the grid. Improved system visibility can be achieved through new sensing capabilities and communication networks. Moreover, these communication networks can also be leveraged to integrate with and monitor DERs through systems such as DERMS. However, it is important to note that a DSO does not need to monitor every single DER in real-time as there are other ways to ensure these systems are staying within operational constraints such as autonomous smart inverter settings and reliance on aggregators. Any investment plan to improve real-time visibility should be specific to each DSO's individual system, should first focus on areas where there are constraints

[70] Institute for Energy Economics and Financial Analysis, Growing the sharing energy economy at 31. https://ieefa.org/resources/growing-sharing-energy-economy.
[71] UKPN, RIIO-ED2 Business Plan 2023 – 2028, at 50.
[72] National Grid, ESMP, at 256.
[73] Eversource, ESMP, at 329.

and leverage a common set of investments where possible to support improved visibility for both integrated system planning and system operations.

5.4.2.4 DER Orchestration

DER Orchestration encompasses the various approaches by which different types and sizes of DERs are dispatched to comply with flexible interconnection provisions and dispatch DER grid services that depend on various factors, including the type, size, and specific interconnection situation for the DER facility. A DSO needs a holistic DER orchestration plan to understand the various DER control strategies to streamline the integration and utilization and to inform any common technical approach and associated investments where possible.

DER Orchestration should support both static and dynamic operating modes
Different DER orchestration approaches are needed to accommodate static and dynamic operating modes to reflect the difference in complexities from operating these DER facilities.

Static operating models include facilities under static connections and flexible connections that do not participate in any grid service markets. These facilities typically require less complex orchestration approaches. For example, if a solar facility is under a static connection and is exporting at all times, the facility is generating with no dispatch, and direct utility control is not needed for this facility. Instead, as is done in many jurisdictions, these facilities must install smart inverters which have autonomous functions to ensure that the facility causes no adverse impacts to the grid. Similarly under a static flexible connection, direct control is unnecessary as a facility could just install hardware to cap exports or imports at the agreed upon limit.

Dynamic operating modes including static connections and flexible connections that are participating in grid service markets, dynamic flexible connections and dynamic flexible connections participating in grid service markets. Given that dynamic operating modes require dispatch of the DERs, these orchestration approaches are often more complex.

DER Orchestration should include common technical standards
DER orchestration should also strive to establish common technical standards across devices, communication protocols and interfaces with DSO systems. Common technical standards will provide a consistent technical approach for DERs to participate in flexible connection and grid services offerings. Moreover, these standards can provide the DSO greater certainty that DERs can be relied upon in system operations.

For devices and communication protocols, common standards typically apply to DER devices such as smart inverters and power control systems.

IEEE 1547.2018 is emerging as the common smart inverter standard in the US which has led to the streamlining of the interconnection process with mandated requirements of using smart inverters for interconnection.

The IEEE 2030.5 communication protocol provides substantial benefits to electrical grid operators by facilitating their connection to and utilization of distributed energy resources (DERs) of varying scales, whether individual or aggregated. Both California (Rule 21) and Hawaii (Rule 14H) have embraced IEEE 2030.5 as the default communication protocol for DER. In Australia, the Common Smart Inverter Profile (CSIP) and the communication protocol IEEE 2030.5 are quickly being adopted nationally, allowing for the scaling of dynamic operating envelopes. Both of these standards have been widely adopted by industry and distribution utilities streamlining the interconnection processes and enabling the wide scale adoption of flexible connection in Australia.

UL 3141 is another emerging standard that is allowing for flexible connections. Distribution utilities have had concerns with relying on ad hoc power control systems to cap or optimize the exports or imports of a facility leading to drawn out testing processes delaying flexible connections. With the recent update to UL 3141, distribution utilities can more quickly enable flexible connections if the facility demonstrates they are using a UL 3141 certified device.

5.5 Integrated System Planning

Objectives: *(1) ensure that there is sufficient generation and system infrastructure capacity to serve customers reliably, safely and affordably; (2) ensure there is sufficient network capacity to integrate large amounts of DERs; (3) consider all solution options, such as competitive DER solutions and innovative uses of existing assets (e.g., flexible interconnection and grid enhancing technologies), to meet system upgrade needs; and, (4) support integration of distribution-connected renewable generation and storage resources to contribute to Maine's clean energy policy goals.*

Now that we understand the DSO Function Objectives ("What") for integrated system planning, we can now evaluate the DSO Function Design Elements ("How"). The following principles, capabilities and processes were identified based on international precedent and United States specific trends as key DSO design elements to support the objective of DSO-driven Integrated System Planning. We will elaborate on each design element in the subsequent sections.

Key Design Elements

Key Principles:

- Bottom-up Approach
- Collaborative + Transparent

Key Capabilities + Processes:

- Planning Network Visibility
- Develop collaborative process with local planners
- Enhanced Forecasting, Simulation, and Network Model Capabilities
- Holistic and Competitive Solution Vetting Process
- Coordination Across Maine Entities

5.5.1 Key Principles

5.5.1.1 Bottom-Up Approach

The planning of the electricity system has traditionally broken down into three components: resource planning (commonly "integrated resource planning" or "IRP"), transmission planning, and distribution planning, with different entities or different departments within large entities responsible for each component. Linkages between the three "siloes" have historically been limited, although some coordination has always been required between IRP and transmission planning.

These siloes made sense for the 20th-century system architecture in which almost all supply resources were interconnected to the bulk transmission system, while the distribution system only provided reliable one-way delivery of energy from the bulk system to consumers. The planning process typically started with 10-20-year forecasts of demand growth, then provided the forecasts to resource planners to develop potential portfolios of new bulk-system generation for which transmission planners determined transmission needs and possibly a small amount of demand response to mitigate extreme peaks. The distribution planners only had to ensure that their radial systems could reliably deliver the energy from the bulk system to the consumers. This approach worked well with the relatively slow, steady growth in demand over the decades. However, this approach alone is insufficient to account for the integration and optimal utilization of DERs.

Located at the "grid edge", DERs can supply substantial amounts of renewable energy close to load centers, to minimize system losses, the need for transmission upgrades and land-use concerns.[74] DERs can also provide grid services to alleviate local distribution constraints on the individual feeders and nodes they are connected to, as well as on upstream assets such as the substation. Distribution utilities have traditionally not had granular visibility into these locations as the system did not have facilities exporting power onto it, nor did it have dynamic and flexible loads such as EVs and batteries.

One implication of these observations is that integrated system planning as envisioned by the Resolve will be more of a bottom-up planning approach, in contrast to traditional centralized, top-down planning processes. A bottom-up approach depends on utilizing more granular information from the grid edge to integrate DERs in a timely, cost-effective manner while exploring opportunities to leverage DERs to meet demand, especially from large new customers and electrification projects, rather than reflexively assuming that all demand growth must be served from the bulk transmission system.

To explore how a more bottom-up planning approach could work, first, consider the conventional top-down resource and transmission planning approaches in common use today. They start with multi-year forecasts of growth in energy consumption, i.e., total or "gross" load before subtracting out any self-supply by customers. Next, the planners forecast and subtract growth of customer-sited (behind-the-meter or BTM) DERs to obtain net load growth scenarios, which reflect the load the system will see at the customer meters. The remaining net load becomes the input to capacity expansion models that offer a menu of various supply resource types with their attributes such as costs and performance characteristics. The resulting capacity expansion portfolios must be juxtaposed to geographic information that reflects constraining factors such as primary energy availability (wind, solar irradiance, proximity to gas pipelines, etc.), land-use constraints, and transmission capacity. Transmission planners can then determine how to upgrade transmission capacity most cost-effectively to integrate each of the capacity portfolios of interest.

Typically missing from the top-down approach is any exploration of the potential to deploy supply close to load centers, connected to distribution, utilizing the built environment as potential project sites. Rather, there's an implicit assumption that all new resources will be interconnected to transmission.[75] Or, if distributed generation is considered at all, it would be represented in the capacity portfolios by allocating an arbitrary portion of a resource type, say, utility-scale solar PV,

[74] Resource planning processes in the U.S. generally do not look to the distribution side as the location of significant amounts of renewable energy supply. This is a mistake that will cost ratepayers more than is necessary to achieve renewable energy goals. Maine should avoid this mistake as it prepares for a high-DER future. A 2016 study by the National Renewable Energy Laboratory (NREL) estimated that Maine could supply 60 percent of its annual electricity demand from solar PV deployed on the roofs of various types of buildings; the figure for the U.S. as a whole was 39 percent. The size of the potential indicates the need for integrated system planning to incorporate a collaborative approach with local jurisdictions and project developers to identify projects to supply demand with local supply to the extent feasible. The NREL study is here: https://www.nrel.gov/docs/fy16osti/65298.pdf

[75] This is the explicit assumption of the National Transmission Planning Study recently released by the U.S. Department of Energy: https://www.energy.gov/gdo/national-transmission-planning-study

to be deployed on distribution, but without any investigation of potential locations for these resources.[76]

A bottom-up resource planning approach, in contrast, would apply the principle of deploying supply resources close to load to the extent technically feasible and cost-effective. This requires a more granular approach than traditional resource planning because it involves identifying potential supply resource locations in the vicinity of existing and anticipated load concentration. Resource planning will therefore need to engage city and county planners and other local entities not traditionally involved in electricity planning, such as transportation, water and sanitation districts, to identify and evaluate potential sites for local energy supply.

The point is that resource planning, under a DER-focused bottom-up approach, must go beyond the customary objective of identifying a portfolio of GW of new capacity to meet a system-level load forecast, and instead build local supply resources that best meet the needs of the people, communities, businesses and public functions who depend on electricity service. By engaging the local entities in DER-based resource planning, decisions about resource types and locations can consider multiple benefits such as climate resilience, economic development, and community health, as well as system operational and infrastructure benefits, in addition to the usual system-level cost, reliability and emissions attributes.[77]

Although this discussion has focused on resource planning, the bottom-up approach will have implications for distribution and transmission planning, to be discussed further below. It will also require new processes for collaboration and transparency between traditional electricity system planners and the local government entities responsible for local energy planning.

5.5.1.2 Collaborative + Transparent

Aggressive climate goals and a high-DER grid introduces several new factors to the planning process that require increased regulatory oversight as well as input from market participants, local communities, the balancing authority and independent technical experts.

Regulators need transparency into the DSO's progress towards accelerating the achievement of the region's climate goals and whether all measures are being taken to decarbonize at least cost while improving reliability. Moreover, integrating and utilizing DERs requires new and more complex processes to identify system needs and choose the appropriate solutions, the outcomes of which can significantly impact market participants, local communities, and the balancing authority. For market participants, these outcomes will determine when and at what cost they can connect DERs (i.e., flexible connections vs. waiting for system upgrades) as well as earn revenue (i.e., flexibility service opportunities) from these DERs. For local communities, these decision points

[76] This is the approach being used in California to develop capacity expansion "pathways" to achieve the state's statutory mandate of 100 percent carbon-free electricity consumption by 2045. The approach is described in detail in this staff presentation: file:///Users/LPersonne/Downloads/TN252852_20231031T110728_SB%20100%20Analytical%20Framework%20Workshop.pdf

[77] The UK Power Networks DSO has established a structure for collaboration with local jurisdictions to support their achievement of local Net Zero plans: https://www.yourlocalnetzerohub.co.uk

will impact whether they can meet their specific energy, climate resilience, equity, and economic development goals. Finally, equity is a top priority for various regions, including Maine[78] to ensure any climate strategies result in shared benefits across diverse populations. The DSO's approach to integrated system planning should embed equity in these processes, identifying these populations and working with regulators, market participants, and local communities to ensure they benefit from DSO investments and DERs.

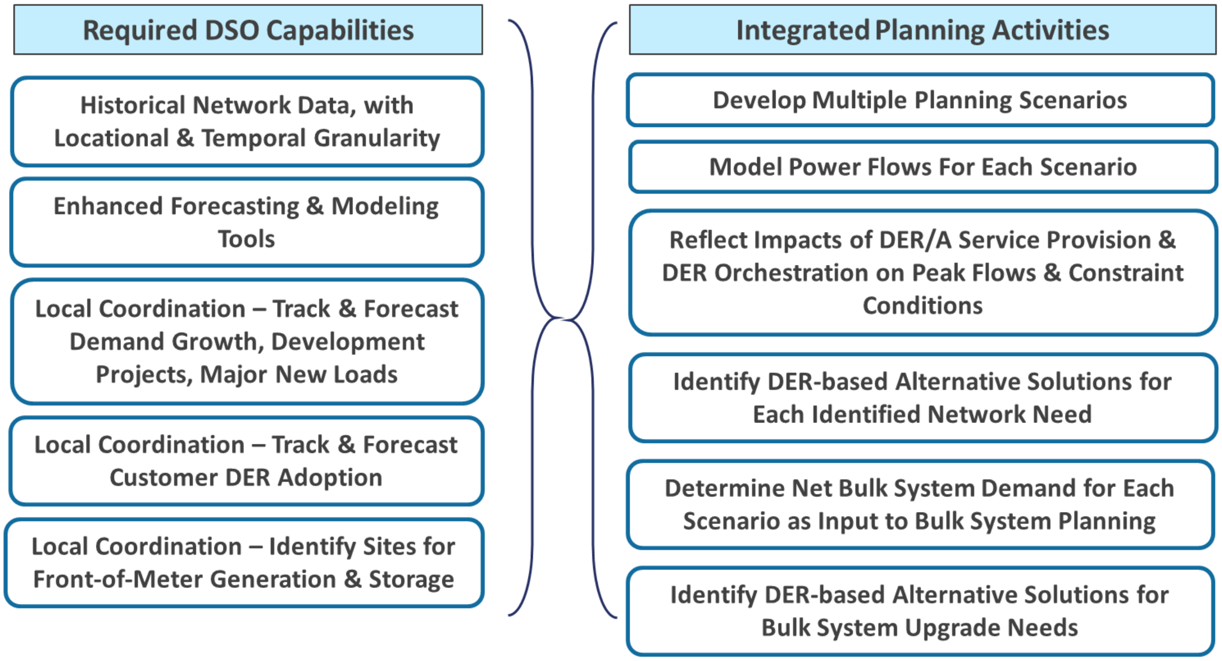
Thus, the development and implementation of these processes should be a collaborative and iterative effort between the DSO, market participants, local communities and independent experts as described throughout the capabilities and processes.

5.5.2 Key Capabilities + Processes

Designing integrated system planning that is bottom-up, collaborative, and transparent involves an interdependent set of capabilities and processes, as described below.

Network visibility and working relationships with local planners and community organizations are foundational to enabling these capabilities and processes. With improved visibility into the distribution system, combined with knowledge of local renewable energy, climate action and economic development project plans, the DSO can forecast distribution system needs on a granular locational and temporal basis. With these granular system needs, the DSO can identify opportunities for flexible connections to integrate more DERs and flexibility services solutions to utilize DERs. Once these forecasts have been developed and the corresponding solutions selected, the balancing authority can incorporate this information into their transmission and resource adequacy planning. Throughout the process, the DSO can share and receive data from a broad set of stakeholders, including the regulator, market participants, local communities, and the balancing authority, to facilitate a collaborative and transparent planning process. We describe each of these capabilities and processes in detail below.

[78] https://www.maine.gov/future/sites/maine.gov.future/files/2023-12/_2023_MWW%20Progress%20Report.pdf, at 6.



5.5.2.1 Planning Network Visibility

A bottom-up planning process starts with improving visibility across the distribution system. Ofgem emphasized the role of enhanced network visibility in its DSO baseline expectations, which were provided as guidance for enhancing network planning and development. Ofgem stated they expect increased monitoring equipment to be rolled out across their network where it has demonstrable net value for network planning and expect the DNOs to submit a network visibility strategy and this should cover the use of all sources of network data and should explain how network monitoring for planning purposes will inform planning decisions, including the use of flexibility.[79] Several key elements should be considered to guide improved network visibility, as described below.

First, improved visibility is needed for the primary system with new levels of visibility for the secondary system. The secondary system is the part of the distribution system that carries electricity from distribution transformers to customer electricity meters which includes individual feeders and their associated nodes - where a majority of BTM DERs are being integrated. Visibility is critical to these parts of the network to understand how much DER can be integrated as well as specific constraints in these areas. UKPN emphasizes the need to build new network visibility and monitoring capabilities at the secondary system level, and evolve existing capabilities at the primary and grid network level, to support an increasingly intelligent network that supports flexible demand and generation.[80]

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[79] Ofgem, Distribution System Operation Incentive Governance Document, February 17, 2023, at 33.
[80] UKPN, RIIO-ED2 Business Plan 2023 – 2028, Appendix 18, at 37.

Second, new visibility for the secondary system is needed on a locational and temporal basis. DERs may interconnect on different parts of the secondary whether it be specific feeders and nodes within a feeder. Moreover, the system is not static in nature but dynamic with conditions changing on an ongoing basis. The benefit of approaches like flexible connections and flexibility services is that they can leverage the flexibility of DERs to mitigate constraints at *specific locations and times on the distribution system*. Thus, this improved visibility should encompass not only more granular *locations* on the grid such as individual feeders and nodes on the secondary system but more granular temporal system conditions.

UK Experience. UKPN identified the main drivers for investing in network visibility and monitoring as an uncertainty in the magnitude, *timing and location* of DER uptake, and to facilitate the delivery and operation of distribution flexibility services.[81] National Grid UK also states that data will need to be collected at key network locations and at a higher frequency and granularity, both in relation to real time system operations and longer term network planning.[82]

While the temporal granularity of specific locations may vary depending on the DSO and the specific conditions of the distribution system, National Grid UK's network visibility strategy provides some insights into the potential level of granularity needed to plan the distribution system. National Grid UK currently uses half-hourly average data to design the network. However, they are finding that intermittent generation has significant variations within the half-hour on a feeder causing half-hourly averages to inaccurately represent actual network conditions.[83]

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[81] UKPN, RIIO-ED2 Business Plan 2023 – 2028, Appendix 18, at 37. https://www.ofgem.gov.uk/decision/riio-ed2-final-determinations

[82] National Grid UK, Network Visibility Strategy, at 9. https://www.nationalgrid.co.uk/downloads-view-reciteme/481978

[83] National Grid UK, Network Visibility Strategy, at 17. https://www.nationalgrid.co.uk/downloads-view-reciteme/481978

Comparison of half-hourly averaged flows against actual flows on a windfarm feeder

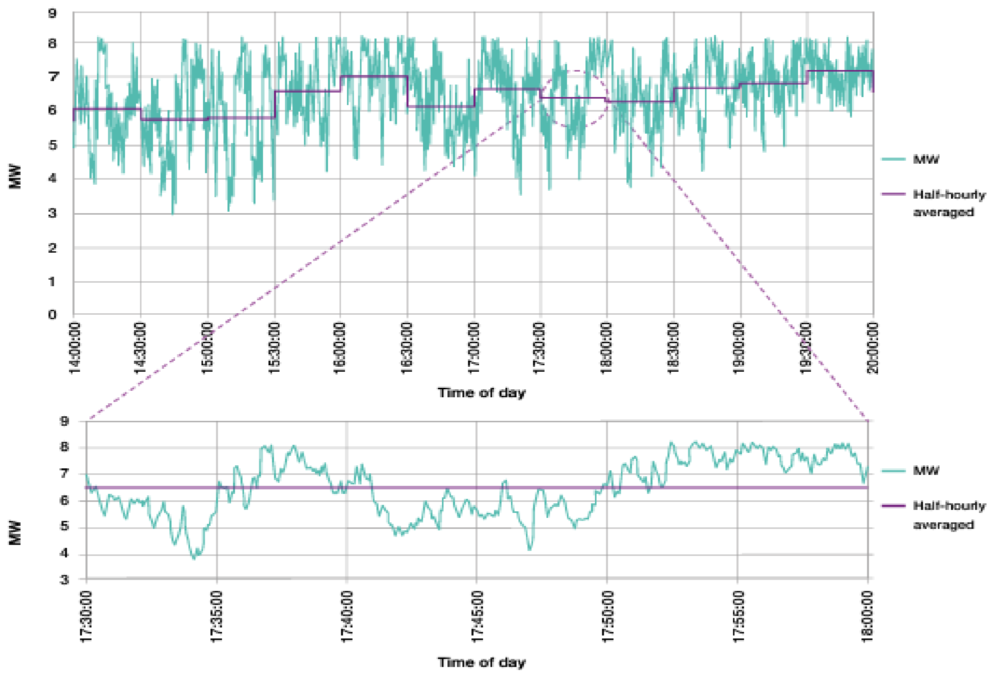

Figure 10 National Grid UK Half-Hourly Averages Flows vs. Actual Flow on WindFarm Feeder[84]

Finally, improved visibility should be gained by leveraging existing data and innovative investments while making targeted visibility and monitoring investments in constrained locations. Installing monitoring and communications equipment can require significant investment and should be done in a strategic and cost-effective manner. Moreover, utilities often have a significant amount of data already available that they are currently not utilizing in system planning. For example, many utilities have deployed smart meter networks which provide hourly usage data for each customer in their service territory. If customer meters are mapped to system assets such as the feeder and substation, preliminary hourly profiles could be developed for these assets which could then be used in planning. This approach immediately allows for more granular system planning and can be supplanted by new monitoring and communication equipment as needed or as constraints grow in particular locations.

UK Experience. UKPN emphasized a "data-first" approach, maximizing the use of existing data to achieve network visibility faster and cheaper, including data already measured on the network, data collected from smart meters, and wider third-party data. Moreover, UKPN is also developing a software-based machine learning tool to enhance visibility and unlock fresh insights into demand on the network which would significantly lower costs and produce results sooner as opposed to hardware investments. UKPN is also only prioritizing the installment of hardware-based monitoring, which requires significant investment in constrained areas of the network.[85]

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[84] National Grid UK, Network Visibility Strategy, at 17. https://www.nationalgrid.co.uk/downloads-view-reciteme/481978.

[85] UKPN, RIIO-ED2 Business Plan 2023 – 2028, Appendix 18, at 37.

National Grid UK is taking a similar approach, leveraging smart meter data to monitor LV feeders without first requiring the addition of monitoring systems. When this data shows that the network is nearing capacity, National Grid UK plans to add additional substation monitoring to ensure the efficient deployment of equipment and resources and allow the management of any constraints in real-time where possible.[86]

5.5.2.2 Enhanced forecasting, simulation and network model capabilities

Bottom-up planning requires more spatially granular forecasting capabilities to understand and plan for system needs on the secondary system. Collaboration with local city and county planners will be essential. Ofgem emphasized the role of this in its DSO baseline expectations provided as guidance for enhancing network planning and development stating they expect the development of enhanced forecasting, simulation and network modeling capabilities, with processes in place to drive continual improvement to meet network and user needs.[87] Several key elements should be considered to guide enhanced forecasting as described below.

Forecasts should be developed in collaboration with local parties to identify and address local energy needs. Enhanced forecasts should look to incorporate significant amounts of data not solely within the utility domain but available from third parties such as local government planners and developers. The DSO should collaborate with local parties such as local government planners and developers to assess local energy needs based on load projections, local electrification initiatives, etc., and identify potential sites for distribution-connected renewable energy supply resources that could meet load growth without requiring new bulk system resources.[88] The DSO and the local planners should specifically estimate the technical potential of maximizing deployment of renewable generation and energy storage on large built structures such as roofs of warehouses, shopping malls and schools to become supply resources to serve local customers. Although technical potential is often received with skepticism in favor of some formulation of economic or market potential, it is important to recognize that economic or market potential is strongly affected by policy, including both technical elements such as interconnection time and cost uncertainty as well as financial elements such as market rules for selling the energy generated by local resources. Once policymakers see estimates of the technical potential of local distributed generation to achieve state policy goals, they can explore policies to facilitate such projects and improve their economic returns. Here we see the interplay between the DSO's market and planning functions.

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[86] National Grid UK, Network Visibility Strategy, at 10. https://www.nationalgrid.co.uk/downloads-view-reciteme/481978.

[87] Ofgem, Distribution System Operation Incentive Governance Document, at 33. https://www.ofgem.gov.uk/decision/riio-ed2-final-determinations.

[88] UKPN's DSO offers a model for local collaboration with its Local Area Energy Planning framework. https://www.yourlocalnetzerohub.co.uk/resource/ylnzh-nz-basics/LAEP-Framework

Forecasts should be conducted across different locations on the LV network. The DSO needs to understand the impacts on the LV network as this is where load and customer-sited DER growth is occurring. There is a need to better understand network utilization, not only at primary level networks but also on secondary networks where the impact of customer DERs such as EVs will be seen. This will enable more accurate forecasts for when interventions will be needed and maximize the utilization of existing networks.[89]

Forecasts should include geographically granular load and DER growth scenarios. Load and DER growth will vary significantly depending on the specific location on the secondary system. Forecasts need to be developed to anticipate this load and DER growth at these individual locations so locational-specific constraints which can be then used to determine the viability of solutions such as flexible connections and flexibility services to meet these needs. These forecasts could also then be aggregated to the T-D interface for coordinating with bulk system planning as discussed in detail in the T&D Coordination section.

Forecasts should be developed for short and long-term horizons based on policy goals. A core objective of the DSO is the accelerated achievement of the State's climate goals and as such the DSO should plan to achieve these goals. To do this, the DSO needs to develop load and DER growth scenarios to not just predict what will happen in the near-term but forecast several potential scenarios to reach these goals. The development of short- and long-term forecasts that model uncertainties can help reflect the effects of multiple technology drivers. Developing multiple scenarios to encompass the range of potential outcomes can help to illuminate a broad range of key drivers of demand and generation on the networks.[90]

Forecasts should be developed in collaboration with local resource planners to minimize distribution system impacts and to avoid long wait times for load and DERs connections. Across the United States, community solar is experiencing significant growth with transportation electrification, and especially large EV projects such as those for medium- and heavy-duty fleet electrification, which are expected to significantly increase as well. If they are deployed independently, both of these types of facilities typically require MW of extra capacity that needs to be added to the distribution system. Under the bottom-up resource planning approach and the principle of deploying supply close to load as described earlier, however, a local jurisdiction can plan to deploy a community solar + storage resource in conjunction with a large EV charging facility, in collaboration with the DSO planners, to minimize the infrastructure requirements of the combined facilities. Otherwise, the timelines required to build out infrastructure for large EV charging projects can be substantial, taking two to five years or more in some situations.[91] This is significantly slower than both customer expectations and commercial vehicle procurement

[89] UKPN, RIIO-ED2 Business Plan 2023 – 2028, Appendix 18, at 37-38
[90] UKPN, RIIO-ED2 Business Plan 2023 – 2028, Appendix 18, at 37-38
[91] https://www.canarymedia.com/articles/ev-charging/a-big-barrier-to-californias-electric-truck-goals-a-backlogged-power-grid

timelines, which can often be less than one year.[92] As such, a DSO should modernize its practices to integrate local resource planning into distribution planning, to proactively identify areas it is expecting significant load and/or DERs, and develop investment plans for these scenarios. If necessary, a DSO could evaluate whether DER solutions, such as flexible connections and flexibility services, can be used as interim solutions to integrate load and DERs as capacity is built. States including Massachusetts[93], Colorado[94], California[95] and New York[96] have all begun processes to develop proactive planning processes to address this issue.

Forecasts should account for the impact of flexibility service options on distribution constraints. Typically, the evaluation of flexibility solutions to address constraints in forecasts occurs after the forecasts are developed and are in the solutioning process. However, embedding flexibility into the forecasting process and accounting for this flexibility upfront can reduce the steps needed to determine the true constraints on the system and ultimately develop solutions. For example, managed charging assumptions could be made for certain types of EV load. There are opportunities to improve the ability to model the behavior of DER and the impact of flexibility service options on network constraints.[97]

Forecasting models should be made available to stakeholders for input and scrutiny. Forecasts are expected to increase in complexity with the outputs having a significant impact on market participants, local communities and the balancing authority. The Integrated System Planning function should provide stakeholders access to the forecasting models including the inputs, methodologies and outputs so that stakeholders can re-run the models with different data, assumptions and sensitivities.

5.5.2.3 Holistic and competitive solution vetting process

Once distribution system needs have been forecast at a granular level, the DSOs need a holistic and transparent solution vetting process to determine whether there are DER-based opportunities to address forecasted needs. In its DSO baseline expectations for DSOs, Ofgem required the DSOs to have transparent and robust processes for identifying and assessing options to resolve network needs, using competition where efficient. Specifically, Ofgem has emphasized the need for the DSO to consider flexibility (i.e., flexibility services) and promote energy efficiency in addition to

[92] National Grid Massachusetts Grid Plan, at 347, https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/18552718.
[93] G.L. c. 164, §§ 92B-92C, through An Act Driving Clean Energy and Offshore Wind, St. 2022, c. 179, § 53 (requires investor-owned electric distribution companies operating in Massachusetts to each submit an Electric System Modernization Plan).
[94] SB 24-218. https://leg.colorado.gov/bills/sb24-218.
[95] SB 410 and AB 50.
[96] NY DPS Proceeding CASE 24-E-0364.
[97] UKPN, RIIO-ED2 Business Plan 2023 – 2028, Appendix 18, at 37-38

innovative use of existing network assets (i.e., flexible connections) and traditional reinforcement.[98] Several key elements should be considered to guide holistic and transparent solution vetting, as described below.

A consistent approach should be developed for valuing flexible connections and grid services. Developing a valuation framework to value both these types of flexibility will allow for a more streamlined approach to assess whether these solutions are more economic and efficient options compared to traditional solutions. Valuing flexible connections may be more straightforward as this relies on technical approaches within the DSO's purview such as active network management and therefore a cost could be estimated to compare against traditional solutions. However, valuing grid services is a more complex process that should be undertaken through the DER market administration function.

A solution vetting process should compare DER-based solutions, such as flexible connections and grid services on a leveled playing field with traditional solutions. While a consistent approach to valuing flexible connections and grid services is important, a companion process is needed to integrate the evaluation of these options into the traditional solutions process. Criteria should be developed to assess both the technical and economic viability of these solutions. Ofgem has emphasized the need for a process where options must be fairly compared against one another, with flexibility used where it is economic and efficient compared to investing in traditional reinforcement or technological solutions.[99]

The solution vetting process should solicit stakeholder input and scrutiny of decision-making. Market participants and local communities should both play a role in shaping the solution vetting process, including developing criteria for evaluating flexibility solutions and the ability to propose solutions.

5.5.2.4 T&D Coordination

The previous section developed the idea of integrating distribution and resource planning based on transitioning to a bottom-up planning approach. Although distribution and resource planning are state-jurisdictional, it should be clear that the bottom-up approach to these components will affect the needs for bulk-system infrastructure additions. Transmission planning is within the scope of ISO/RTO and BA responsibilities, which for Maine are ISO-NE and New Brunswick Power, respectively. The DSO's integrated system planning must therefore include provisions for coordinating with the bulk system planning processes.

It is neither necessary nor within the scope of this report to consider any changes to ISO-NE's or NBP's existing transmission planning processes. We therefore take their processes as given and

[98] Ofgem, Distribution System Operation Incentive Governance Document, at 34. https://www.ofgem.gov.uk/decision/riio-ed2-final-determinations.

[99] Ofgem, Distribution System Operation Incentive Governance Document, at 34. https://www.ofgem.gov.uk/decision/riio-ed2-final-determinations.

focus on the inputs the DSO would provide to those processes. ISO-NE and NBP plan “regional” transmission, i.e., facilities at 115 kV voltage level and above, while the transmission-owning utilities in Maine, Versant and CMP plan their own lower-voltage facilities. With regard to the integrated system planning function of the DSO, the planning of lower-voltage transmission would not need to be different in terms of tools and procedures from how it works today, though its inputs would reflect the results of the integrated distribution and resource planning approach described earlier. That is, similar to today, the bottom-up approach would result in a net amount of energy supply that needs to be imported from the bulk system at each T-D interface, and the lower-voltage transmission facilities would need to be capable of delivering that energy to the local distribution systems. The principal difference to today would be about the magnitude of energy the lower-voltage transmission needs to deliver, which would be less than it would be with greater reliance on bulk-system supply.

Coordination with the bulk power system then comes down to the inputs the DSO provides to the ISO/BA and the ISO/BA’s determination of upgrades needed to the high-voltage facilities of Maine’s transmission owners. Bottom-up resource and distribution planning should result in less need for energy imports from the bulk system, which in turn should result in less need for more transmission capacity on the utility high-voltage systems than under current planning practices.

One approach to incorporate bottom-up resource planning into transmission planning would be to first work with local planners as discussed above to identify local energy supply projects that could meet a share of anticipated future load. This could involve more than one planning scenario. Then for each local energy scenario, subtract the potential for local supply from the system net load forecast, to get a “residual” net demand forecast that must be served from the bulk system and will require investment in new bulk system supply and transmission capacity. Existing capacity expansion models could be suitable for this step, but they would be applied to smaller quantities of demand due to the removal of demand served by distribution-connected supply. In this manner the bottom-up planning approach sees the bulk system as the residual source of supply, after deploying all cost-effective local DERs.

5.6 DER Market Administration

Objective: *To establish and operate a distribution-level market platform and market mechanisms to enable DERs to participate in economic transactions for energy and grid services in coordination with wholesale markets to ensure efficient whole-system outcomes and support reliable whole-system performance.*

Now that we understand the DSO Function Objectives ("What") for DER Market Administration, we can evaluate the DSO Function Design Elements ("How"). The following principles, capabilities, and processes were identified based on international precedent and United States-specific trends as key DSO design elements to support the objective of DSO-driven DER Market Administration. We will elaborate on each design element in the subsequent sections.

Key Design Elements

Key Principles:

- Diverse Market Mechanisms
- Distribution-level Market Platform
- Market-Operations Integration

Key Capabilities + Processes:

- Export of Excess Energy
- DER Participation in Wholesale Market
- Provision of DER Grid Services
- "Stacking" of Grid Services
- Operation of Distribution-Level Market
- Coordination with Bulk-system Wholesale Markets

5.6.1 Key Principles

5.6.1.1 Diverse Market Mechanisms

This report uses the term "market" to include a wide range of market mechanisms and economic transactions in which DERs and DERAs can earn revenues for various services beyond whatever private benefits they provide to end-use customers who install them on their premises. The term "market" is intended to include, for example:

- The rate a utility or load-serving entity (LSE) pays to a customer with rooftop solar or other on-site DERs for excess power injected into the grid;
- Use of standard-offer, technology-neutral, grid service tariffs;
- Use of a request for proposals (RFP) to solicit bids to deploy DERs to avoid or defer an infrastructure upgrade;
- A power purchase agreement (PPA) between a distribution-connected energy supply resource and an LSE;
- A centrally-cleared auction market in which suppliers offer energy or grid services at their own preferred prices.

The point is that the central objective of a DSO market function is to enable DERs to engage in economic transactions whereby they can earn revenues for providing value to the electricity system and other system participants. The ability to earn revenues via well-designed economic transactions is key to incentivizing DER owners to utilize the full performance capabilities of their assets for the benefit of the whole system, which in turn is the recipe for realizing the greatest total societal value from DER investments. That said, effective economic transactions may take many different forms.

5.6.1.2 Distribution-level Market Platform

The objective of a DSO-provided market platform is to enable the DSO to perform all the required activities involved with DER participation in economic transactions and to have a comprehensive view of all the transactions DERs are engaged in within each local distribution area and each operating hour. As described above in the section on system operation, distribution-level grid services that DERs provide will entail DSO identification of operational needs, specification of performance requirements, pre-qualifying candidate DERs and DERAs to provide each service, some sort of procurement mechanisms, measurement of DER/DERA performance of services, and financial settlement for services provided. In addition, for DER/DERAs that participate in the ISO markets, the market platform would also track these transactions to ensure that the DSO is aware of all DER/DERA market activities in each operating hour. From an operations perspective, the DSO needs this comprehensive awareness of DER activity to prevent any unexpected operational impacts. The platform would also be valuable in integrated system planning by maintaining a historical record of DER/DERA service provision.

5.6.1.3 Market-Operations Integration

It is important to recognize that the two core DSO functions of reliably operating an electricity network and administering energy markets can be tightly integrated, although it is common in the industry to think of them as independent functions. The design of a DSO-administered market for DERs must consider the linkage between market and economic transactions and incentives for

DERs to operate in support of reliable grid operation.[100] The incentive effects of DER economic transactions should also be linked to the system planning function, as discussed in the previous section.

The main types of possible DER market transactions are listed below in increasing order of complexity. All of these can provide system benefits to some degree and enhance the value of DERs. To maximize the value of DERs in the high-DER power system, the DSO should support all of these, but some will require market design innovations and enabling regulations and may warrant a phased implementation.

i. Customer-sited DERs that export excess energy production to the grid at certain times of day and receive a regulated rate for that energy. This does not involve active market participation by the DERs, but it is a familiar concept that's been in use as "net energy metering" or "net billing" in many jurisdictions. It is being challenged in many places in recent years due to concerns about shifting of utility costs onto non-solar adopting customers.

ii. DER or DERA (VPP[101]) participation in the ISO markets for energy and ancillary services, under the ISO's implementation of FERC Order 2222. This order has major implications for the distribution utilities in ISO/RTO regions, simply because DERs/DERAs must use the physical distribution system to deliver market services to the ISO. Since FERC issued the order in 2020, the ISOs/RTOs have convened stakeholder working groups to design the essential functions and rules, including functional capabilities distribution utilities will need to support DER/DERA wholesale market participation. Thus, FERC Order 2222 has been driving the design of many of the functional capabilities DSOs will need to expand the set of economic transactions available to DERs.

[100] The Locational Marginal Pricing (LMP or "nodal pricing") markets operated by the U.S. ISOs and RTOs, including ISO-NE, illustrate such linkage. The LMP market clears energy buy and sell bids and offers while simultaneously scheduling buyers' and sellers' use of transmission in a non-discriminatory manner that supports reliable real-time operation. To do this it runs a "security-constrained economic dispatch" ("SCED") algorithm, a cost-minimization program that incorporates an accurate map of the transmission network and its current operating conditions, to schedule participating resources to balance supply and demand while respecting the operating limits of all grid facilities. The SCED produces "nodal" prices or LMPs at each "node" of the grid, i.e., each point of interconnection of a generating resource, a T-D interface substation, or an import-export tie to an adjacent BA. These LMPs accurately reflect the value of injecting or withdrawing power at each node, given the current state of the grid. Nodes where there is capacity to inject more power will have higher LMPs than nodes where more power injection will cause congestion. Nodes where additional load can be served by low-cost supply will have lower LMPs than nodes where serving additional load will cause congestion and require more costly supply resources. In this way the LMP market forms prices that incentivize performance that aligns with transmission system conditions and needs. This tutorial explains LMP in the ISO-NE market: https://www.iso-ne.com/static-assets/documents/100016/20240924-iwem-02-locational-marginal-pricing.pdf -

[101] The term "virtual power plant" ("VPP") has recently gained currency in the industry, but a VPP is the same thing as a DER aggregation ("DERA"), that is, a group of DERs at different locations on the system whose activity is coordinated for the purpose of providing services to the power system or participating in an energy market.

iii. Aligning DER/DERA activity with distribution grid needs. In addition to ISO market participation, a key to realizing the full system and societal value from DERs while minimizing their problematic operational impacts is to enable diverse ways to coordinate DER activities, to align the operating incentives of DERs with system needs and high-level policy objectives. To this end, the DSO could implement passive mechanisms such as time-varying distribution rates or participatory mechanisms such as compensation for aggregators to form VPPs to smooth net load profiles on individual circuits. This element points to an intersection of the DSO's operating and market functions, recognizing that economic transactions can be a powerful way to align resource operating incentives with system needs. As these types of transactions are standardized and incorporated in the system planning procedures they can be expected to reduce the need for system upgrades compared to scenarios where DERs grow in response to customer adoption without any mechanisms and incentives to align their behavior with grid conditions.

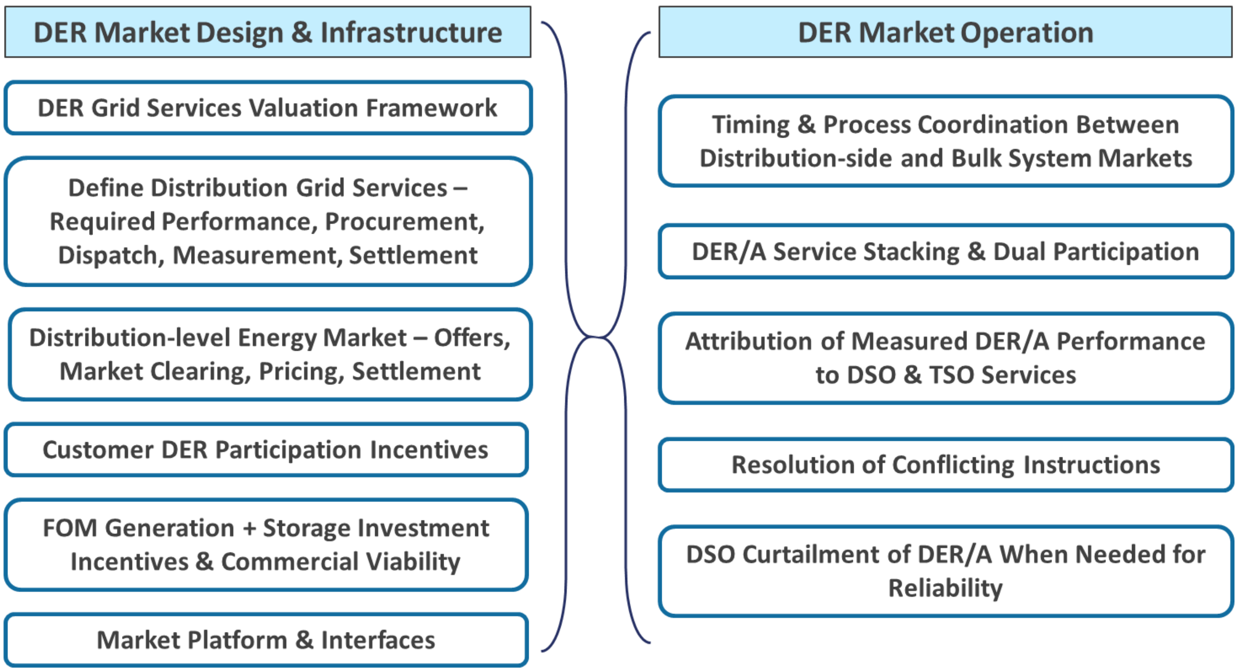
iv. DERs can serve as non-wires alternatives (NWA) to avoid or defer distribution system upgrades. Under the DSO's planning function the DSO would identify needed upgrades and then consider DER-based alternatives, potentially soliciting NWA proposals through an RFP. The DSO would be the buyer of such services, and then would dispatch them as part of its operational function to perform as needed under current operating conditions. The previous discussion on the DSO's planning function expands on the topic of NWA.

v. DER could also provide NWA for transmission system upgrades, for which the ISO/BA would be the buyer and the DSO an essential facilitator.

vi. Distribution-level energy markets in which the sellers are DERs and the buyers are local end-use customers and load-serving entities. The DSO would be the market operator or administrator. One variant of this is "peer-to-peer" ("P2P") transactions in which one energy customer sells excess energy to another customer. Another variant is an auction market where DERs submit offers to sell energy and customers or LSEs submit bids to buy energy for a specific time interval and the DSO's market mechanism clears the market, balancing supply and demand while accounting for energy losses and respecting network operating limits. For such markets, the energy produced and consumed must be located within a single local distribution area (LDA), i.e., the distribution network associated with a single T-D interface, to ensure that the energy generated goes entirely to serve local load without requiring the use of the transmission system.

5.6.2 Key Capabilities + Processes

The general requirements for the DSO's market administration function are incremental to the requirements for its network operation function. In particular, the DSO must have an accurate network model and DER registry as described above, with effective "situational awareness" mechanisms to ensure accurate knowledge of current system conditions and DER status. In addition, market administration requires settlement-quality metering and data validation to measure and compensate for the DER/DERA performance of services. Depending on the DSO design adopted, the DSO market administrator would then perform the settlement function for at least some and perhaps all types of DER/DERA economic transactions, i.e., at least the ones involving distribution grid services, and potentially ones involving wholesale market participation, depending on the DSO design adopted. Where a DERA provides services, the emerging construct for metering and settlement has the buyer of services (the DSO or ISO) settling with the DER aggregator, and the aggregator then settling with the individual DERs in the DERA. Under this construct the DER aggregator would also provide settlement-quality meter data to the DSO or ISO settlement process. However, the involvement of an aggregator would not eliminate the need for the DSO to have visibility to individual DERs for performing its network operation function.



5.6.2.1 Export of Excess Energy

The export to the grid of excess energy produced by BTM customer-owned DER is a type of transaction that has been in use for many years as “net energy metering” and more recently as “net billing.” With regards to DSO functional needs, there is nothing more required to enable this.

5.6.2.2 DER Participation in Wholesale Market

Since FERC issued Order 2222 in 2020, DER/DERA participation in ISO/RTO markets has been an ongoing subject of ISO/RTO working groups and federal regulatory filings and has prompted distribution utilities in the ISO/RTO areas to examine the operational enhancements they would need to support such activity.

A successful program of DERA participation in ISO markets must address the main objectives of the DER provider, the ISO and the DSO. The DER provider needs a predictable, stable revenue stream from market participation. This means having confidence that it will be able to fully deliver on an ISO market dispatch with minimal risk of curtailment by the DSO. The ISO also wants to be confident that participating DERAs will fully comply with its dispatch instructions. ISOs may see this as a significant risk because they don’t have visibility to distribution system topology, much less current distribution operating conditions, unlike the visibility they have to transmission-connected resources. Finally, the DSO is wants to be sure DERA participation in the ISO does not compromise its ability to maintain reliable service to end-use customers.

Meeting these objectives involves a combination of pre-operational and real-time activities. Pre-operational activities establish the static conditions for DERA participation — interconnection of individual DERs, and DSO review and approval of a proposed aggregation of DERs to form a DERA or VPP. DSO studies for this purpose typically assume "normal" grid configurations and operating conditions. The interconnection agreement or aggregation agreement between the DSO and the DER or DER aggregator, respectively, will specify operating requirements such as inverter settings, use of dynamic operating envelopes, and procedures for the DSO to limit DER operation under abnormal conditions. These pre-operational activities aim to reduce the need for unexpected curtailments of DER activity, thus reducing the DER/DERA's risk of being unable to fully comply with ISO dispatches.

Real-time activities involve communication between DSO, DER provider and ISO about current operating conditions that impact DER performance and, when needed, DSO over-ride of ISO dispatch instructions to maintain reliable system operation. There are alternative possible ways to configure the needed information exchanges, which a more detailed DSO design effort would consider. In any case, the principal objective is to increase confidence in the DER/DERA's ability to comply fully with ISO market schedules and dispatches while minimizing and managing any adverse impact on distribution system operation.

5.6.2.3 Provision of DER Grid Services

The use of customer or third-party DERs/DERAs to support real-time operation or to substitute for a distribution upgrade is becoming a promising possibility with the continuing improvement in DER performance, scalability and cost-effectiveness. Also, with the growth of DERs through customer adoption (rooftop solar, batteries, EVs), distribution utilities have had to quantify and provide information on "hosting capacity," which is an indicator of how much DER capacity can be installed on a given distribution circuit without violating operating limits.

Although growth of customer-sited DERs has initially and legitimately been seen as a challenge to distribution operation, DER performance characteristics can be harnessed to reduce adverse grid impacts and increase the capability of the grid to accommodate even higher DER amounts without grid upgrades. For example, the calculated hosting capacity of a circuit may indicate how much rooftop solar can be installed on buildings on the circuit without daytime solar production exceeding the circuit's minimum daytime load. However, if customers install solar plus battery storage instead of solar PV only, or if shared community storage is installed on the circuit, excess daytime solar production can be captured and stored so that the original hosting capacity limit would no longer be binding.

The previous section on the DSO's integrated planning function discusses how planning could incorporate the use of DERs/DERAs for distribution grid services. That will depend, of course, on having well-defined services that the DSO is procuring through its market function. For administering markets for DERs/DERAs to provide distribution services, the DSO will need to develop specifications of the services it needs, typically expressed as an amount of real or reactive power to be injected or withdrawn at a specific location during a specific time frame. Because grid conditions can change dynamically, the service requirements may be stated as an amount of capacity that must be available to the DSO for scheduling or real-time dispatch. Specification of the services would include provisions for real-time telemetry, performance measurement and a compensation structure comprised of a capacity payment for availability and a performance payment for responding to each dispatch.

The DSO would need to determine how to procure the needed services, which might involve a variety of mechanisms, such as: an RFP for a specific long-term NWA that could be met by deploying new DERs at the appropriate location; short-term reverse auction mechanisms for needs that are seasonal or temporary; rates or tariffs available to all DERs in an area, where the need can be met with a statistically reliable response from some portion of the DERs. Another possible procurement mechanism might be to incorporate DER reserve capacity into a distribution-level energy market, analogous to the ISO integrated energy and ancillary service markets operating today.

5.6.2.4 "Stacking" of Grid Services

Service stacking is an attractive concept because it could enable DERs/DERAs to maximize their economic value. All the requirements associated with ISO market participation and distribution grid services discussed above still apply, while stacking adds some additional considerations, such as:

- Which services can be stacked by the same resource during the same operating interval;
- Could a resource partition its total capacity and allocate different portions to different services without the two services affecting each other;
- How to resolve conflicting operating instructions for a resource from the DSO and ISO;
- How to allocate a resource's measured activity (e.g., energy production) between two services it provides in the same time interval while preventing double payment.

The section below on the coordination of the DSO's market administration function with the ISO wholesale market illustrates another potential formulation of the service stacking concept that could be part of the DSO's distribution market design.

5.6.2.5 Coordination with Bulk-System Wholesale Markets

Markets for DERs will have impacts on the ISO wholesale markets in two ways that point to the need for DSO coordination activities. The first way is indirect, as distribution-level transactions affect the net load the ISO will see at the T-D interface. The second way is direct, as DERs and DERAs participate in the ISO markets based on the capacity they have available after taking account of any distribution-level transactions they are committed to and any distribution system constraints that may limit their performance.

5.7 Data Access and Management

Each of the core DSO functions depends on the flow of data between the DSO and external parties. Moreover, different types of data are needed depending on the specific use case, including customer, system, market, and DER data. Thus, a DSO needs a comprehensive data sharing strategy across all the core DSO functions. Below, the report describes each use case for data, including the specific data needs as well as data sharing approaches.

Objective: *To ensure that all requisite grid actors, including DSO, ISO, and DER market participants, have sufficient data and visibility to facilitate the efficient and reliable deployment, operation and utilization of DERs.*

Now that we understand the DSO Function Objectives ("What") for data access, we can now evaluate the DSO Function Design Elements ("How"). The following principles, capabilities and processes were identified based on international precedent and United States specific trends as key DSO design elements to support the objective of DSO-driven Data Access. We will elaborate on each design element in the subsequent sections.

Key Design Elements

- ♦ Key Data Categories
- ♦ System Operations Use Cases
- ♦ DER Markets Use Cases
- ♦ Integrated System Planning Use Cases
- ♦ Data Platforms & Sharing Mechanisms
- ♦ Data Sharing Requirements

5.7.1 Key Data Categories

There are several core categories of data that are typically shared between a DSO and third-parties. We break down these data categories based on the flow of information: DSO to third party and third party to DSO.

5.7.1.1 DSO to Third Party

Customer Data: This may include information about the individual customer which typically provided upon customer consent. This may include the customer's bills, interval and historical usage, enrolled rates and programs as well the specific locations in relation to the distribution (i.e., feeder and substation, etc.) and bulk power system (i.e., transmission zone, etc.)

System Data: This may include a broad set of information about the distribution system, including the physical relationship across different assets (e.g., substations, circuits, nodes, etc.), the corresponding rating, capacity, constraints, upcoming investments, and interconnected, in-queue, and forecasted DERs.

Market Data: This may include a broad set of information related to customer and DER market participation including rates, tariffs, locational pricing as well participation and the associated performance in various market offerings.

Policy Goal & Performance Metric Data: This may include information related to clean energy deployment, other policy objectives as well as any performance metrics the DSO is required to track and/or achieve.

5.7.1.2 Third Party to DSO

DER Data: This may include information about both DERs that will or already have connected to the system including size, location and operating profiles of these assets including any curtailment or flexible connections schemes they are obligated to participate in.

Community Data: This may include information from specific communities or municipalities in the DSO service territory which could include their clean energy plans, and the associated activities planned such as DER deployment, energy efficiency etc.

Below, we identify the key use cases for multidirectional data sharing for each function and the corresponding data needed.

5.7.2 System Operations

The following are some of the key data-sharing use cases for system operations:

Anticipating System Constraints *(System Data)*
DER developers need access to more real-time system information to identify and anticipate constraints ahead of time and be ready to respond via future dispatch signals.

Flexible Connection DER Dispatch *(System + DER Data)*
Both the DSO and the DER operator need a real-time data exchange under flexible connection agreements to ensure DERs can be dispatched and curtailed when necessary. This will require monitoring of both system and DER data to both identify when curtailments should occur, send curtailment signals to the DER and verify that the curtailment was successful.

DER Grid Services Dispatch *(System + DER + Market Data)*
Both the DSO and the DER operator need a real-time data exchange under market participation obligations to ensure DERs be dispatched to provide grid services when necessary. This will require monitoring of both system and DER data to both identify when grid services are needed, send signals to the DER and verify that the grid service was provided.

T&D Coordination *(System + Market Data)*
The balancing authority needs access to system and market data to ensure that bulk power system operations are done in coordination with the distribution system. Specifically, the balancing authority needs access to DSO DER dispatch schedules so that the dispatch of DERs can be coordinated to maximize benefits across the system.

5.7.3 DER Markets

The following are some of the key data sharing use cases for administering DER markets:

Flexibility Procurements *(System + Market Data)*
DER operators need access to granular information on where flexibility is needed on the distribution system and the value of that flexibility to inform whether they will participate in the appropriate market mechanisms such as auctions.

DER Grid Services Dispatch *(System + DER + Market Data)*
This use case overlaps with system operations. The signal that is sent as part of the dispatch should include both an operational constraint and the associated price for mitigating that operation constraint.

Market Settlement *(Customer Data)*
DER operators need access to their customer data including metering data to demonstrate that they did respond to the price signal and thus should be appropriately compensated. Metering data is often used for settlement in wholesale markets as well.

T&D Coordination *(System + Market Data)*
These data access needs overlap with the T&D coordination use case for system operations.

5.7.4 Integrated System Planning

The following are some of the key data-sharing use cases for integrated system planning:

Regulatory & Policymaker Oversight *(Policy Goal & Performance Metric + System Data)*
Regulators and policymakers need to be able to monitor the DSO's performance towards state policy goals as well the ability to review investment proposals. This includes information on clean energy deployment, market offering participation as well the information filed with any investment proposals such as a rate case.

DER Project Siting + Proposing Solutions *(Customer + System + Market Data)*
DER developers need ongoing access to data to acquire customers and/or land, scope the economic feasibility of projects and ultimately site these projects. Specifically, developers need three types of data - customer, system and market data. Customer data is needed to size solutions based on a customer's energy usage (i.e rooftop solar). System data is needed to size and curtail solutions where necessary and anticipate any upgrades based on the availability of capacity on the system. Finally, market data is needed to understand the economic viability of the projects based on evaluating different rates and compensation mechanisms for the solution.

Forecast Vetting *(System Data)*
Government agencies, independent reviewers and public interest groups need access to system data to verify and iterate on the DSOs forecasts. Making the forecasting models available, including the inputs, methodologies, and outputs, will allow for an independent review of the results and increase confidence in the certainty of the DSO's forecasts and any solutions selected. Moreover, the need for more proactive planning and longer-term planning horizons will increase the complexity of forecasts. Making these forecast models available allows stakeholders to collaborate with the DSO to refine these models to meet the growing complexity of the system.

T&D Coordination *(System Data)*
The balancing authority needs access to system data to ensure that transmission and resource planning is done as efficiently as possible in coordination with the distribution system. Specifically, the balancing authority needs access to the aggregate forecasts of both load and DER growth to determine potential constraints on the transmission system and account for DER supply its a broader resource planning exercise.

5.7.5 Data Platforms & Sharing Mechanisms

Each of these use cases are critical to each of the DSO functions described above and will require the ongoing sharing of data and with the data needs likely evolving over time. Thus, the DSO should support these use cases by developing modern and scalable solutions to serve as a - a data platform. A data platform serves as digital means to easily and quickly access, analyze and respond to information.
A data platform could have different "sub-platforms" within the overall platform with different levels of sophistication depending on the data needs. For example, a centralized data platform may be sufficient for a significant portion of use cases related to planning and market procurements. However, a separate data platform may be needed for certain operational use cases where data is directly communicated to devices (ex: DERMS sending signals directly to a DER facility).

Centralized data platforms are emerging across DSOs and distribution utilities within the US. Each of the UK's DSOs, including UKPN and National Grid UK, currently provide data platforms that serve as a one-stop for a broad set of data. UKPN includes data such as network operational data, system maps, long-term development plans, curtailments and specific data for local energy planning.[102]

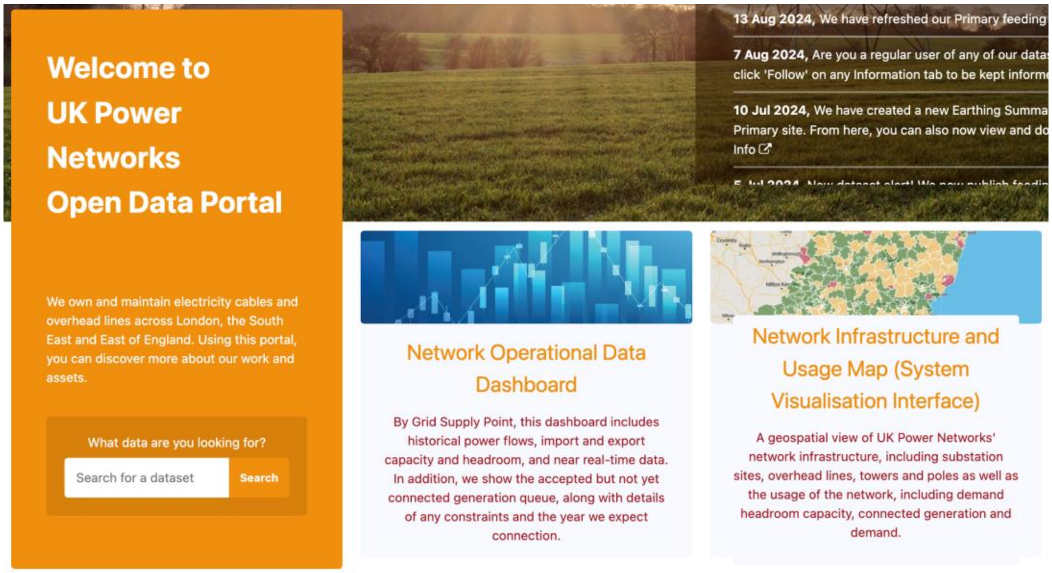


Figure 11 UK Power Networks Open Data Portal[103]

National Grid UK's portal includes current connections to the system, flexibility, forecasted scenarios, curtailments etc. Moreover, both DSOs permit users to request data currently not available and provide updates on new datasets that will be made available.

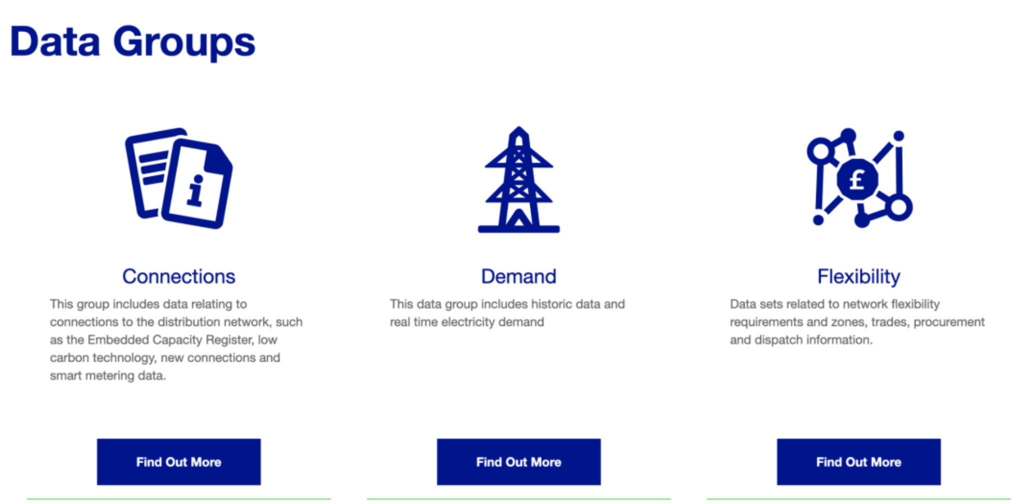


Figure 12 National Grid UK Open Data Portal

102 https://ukpowernetworks.opendatasoft.com/
103 https://ukpowernetworks.opendatasoft.com/

Several initiatives in the United States are also moving towards similar data platforms with New York currently building a statewide platform[104], the Integrated Energy Data Resource (IEDR) to provide access to customer, system and market data. The Illinois Commerce Commission (ICC) recently ordered both Commonwealth Edison[105] (ComEd) and Ameren Illinois[106] to explore and build consensus with stakeholders on a similar integrated data platform. ComEd has made initial commitments to scope a similar platform[107] to NY to provide not only these data types but clean energy deployment and performance metrics.

Figure 13 NYSERDA Integrated Energy Data Resource[108]

Moreover, several New England distribution utilities, including Eversource, National Grid, and Unitil, have jointly submitted a proposal for federal funding to provide a joint platform for customer data access and develop a DER registry.[109]

5.7.6 Data Sharing Requirements

How a data platform is designed is critical to ensuring data from the platform can be easily accessed and analyzed in a scalable manner. There are several key components to consider in the development of a platform:

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104 https://iedr.nyserda.ny.gov/.

105 ICC Order, ComEd Grid Plan, at 287. https://www.icc.illinois.gov/docket/P2022-0486/documents/345316/files/602913.pdf

106 ICC Order, Ameren Illinois Grid Plan, at 33-34. https://www.icc.illinois.gov/docket/P2022-0487/documents/345318/files/602917.pdf

107 https://www.icc.illinois.gov/docket/P2022-0486/documents/350981/files/613798.pdf.

108 https://iedr.nyserda.ny.gov/

109 https://energynews.us/newsletter/new-england-utilities-plan-transformational-data-platform/.

Access Method: Different access methods should be provided to support the different levels of sophistication and interest across different stakeholders. Certain stakeholders may find dashboards and other visualizations to be sufficient while others may require access to the datasets themselves. In this case, less sophisticated stakeholders need to be able to download spreadsheets while others may want access via an Application Programming Interface (API), which allows for the transfer of large amounts of data to a third-party software system for more sophisticated analysis.

Data Standards: Existing data standards should be utilized where possible so that stakeholders can access a common set of data fields across each different type of data. Some examples of data standards including Green Button Connect for customer data and the Common Information Model for system data.

Customer Consent & Authentication: Individual customer data should only be provided to DER developers and operators upon consent from the customer. Moreover, the process by which customers provide consent should be both modern and secure, similar to how customers can easily share sensitive finance and medical information today.

Security & Layers of Access: Depending on the system data needs, publicly making some system data information available may cause grid security issues. The DSO should work with stakeholders to identify which specific types of system data sharing may cause grid security issues and develop solutions such as non-disclosure agreements to provide this data through a more secure process where possible.

Common requirements across DSOs: If there are multiple DSOs within a state market operating separate data platforms, the DSOs should strive to have a uniform experience across the data platform requirements to streamline the experience of market participants and other stakeholders utilizing this data as part of the planning process.

6. Enhanced DSO Functions and the Resolve's Objectives

The report examines whether a distribution system framework comprised of the DSO functions specified in the Resolve, as elaborated in the previous section, could better achieve the Resolve's objectives to integrate and utilize DERs to accelerate the achievement of Maine's climate goals in a way that increases cost savings and system performance and reliability across the distribution and transmission systems.

6.1 Accelerating the achievement of the State's climate goals

The 20th-century electricity system was primarily built using supply resources that were interconnected to the bulk transmission system, while the distribution system only provided reliable one-way delivery of energy from the bulk system to consumers. The planning process typically started with 10-20-year forecasts of demand growth, then provided the forecasts to resource planners to develop potential portfolios of new bulk-system generation for which transmission planners determined transmission needs, and possibly a small amount of demand response to mitigate extreme peak system loads. The distribution system only had to ensure its radial systems could reliably deliver the energy from the bulk system to the consumers. This approach worked reasonably well with the relatively slow, steady growth in demand over the decades.

In recent years, however, several trends driven by State climate goals have prompted reconsideration of solely relying on bulk system supply resources. First, the drive to build new renewable generation and retire fossil fuel generators has elicited a large volume of bulk-system generation projects that has far exceeded the historical rate of new resource development and has congested transmission planning and interconnection processes. Moreover, the preferred locations for renewable generation are often in areas with limited or no transmission access. As a result, it's appearing increasingly risky to depend on deploying new bulk-system renewable generation to meet clean energy targets by the prescribed dates, even before facing any significant load growth.

Second, the historically dependable, relatively constant rate of load growth has given way, at first and briefly to a flattening of load growth to near zero in many areas, then followed by a slew of massive load growth projections based on anticipated electrification of fossil fuel uses in transportation and buildings plus the addition of massive new loads in the form of computing centers for data management, artificial intelligence (AI), and digital currency mining. The bulk system impacts of these load projections make it look even more risky to depend entirely on bulk-system supply to meet climate targets and are driving growing interest in deploying supply on the distribution system close to major loads.

Third, the scalability of DER generation and storage are demonstrating that it could be cost-effective and faster to site supply close to load and reduce requirements for bulk generation and transmission.[110] Moreover, DERs such as Virtual Power Plants (VPPs) can have shorter deployment timelines than bulk power assets because they require less siting, permitting, and construction effort and avoid land-use constraints.[111] Granted, the rapid growth of DERs challenges the conventional one-way kWh-delivery architecture of electric distribution and requires upgrades to distribution system functional capabilities. But that would be a worthwhile cost if the best and possibly only way to meet climate targets on time and cost-effectively is to accelerate deployment of distributed generation and storage as a major share of the State's renewable energy supply.

Finally, it's important to recognize that electrification solutions, including electric vehicles, EV chargers as well as smart water heaters and heat pumps can also be viewed as DERs themselves. The deployment of these DERs is critical to decarbonize the transportation and buildings sectors and to provide grid services to support integration of distribution-connected generation and storage resources.

These trends indicate how DERs can play an integral role in accelerating the State's climate goals.

6.2 Demonstrable reduction in electricity costs for customers

The integration and utilization of DERs can reduce electricity costs, compared to pathways to the State's policy targets that rely primarily on transmission-connected resources, in several ways.

First, in accordance with the laws of physics, distributed generation plus storage (DGS) resources located close to load centers do not rely on transmission to move energy from supply source to load. These energy supply transactions will appear to the bulk system as reductions in net load at the affected T-D interfaces and will not drive transmission upgrade needs.[112]

DER services procured by the DSO can reduce peak loads at the distribution circuit level and at the T-D interface level, thus reducing the need for peak-load related distribution and transmission upgrades, respectively. Historically the need to meet peak loads has been a major driver of infrastructure costs because it was impractical or unreliable to try to mitigate peak loads at the source. DER technologies eliminate that legacy constraint.

Coordinating DERs at the circuit level to flatten net load profiles can increase the hosting capacity of the circuit without expanding its physical capacity. Hosting capacity has been a constraint on

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[110] The California ISO's 2018 transmission plan recommended cancellation of $2.6 billion in previously approved transmission reliability upgrades largely because the growth of DERs in the areas eliminated the projected violations the upgrades were intended to solve.
[111] U.S Department of Energy, The Future of Resource Adequacy at 24. https://www.energy.gov/sites/default/files/2024-04/2024%20The%20Future%20of%20Resource%20Adequacy%20Report.pdf.
[112] The California ISO's 2018 transmission plan recommended cancellation of $2.6 billion in previously approved transmission reliability upgrades largely because the growth of DERs in the areas eliminated the projected violations the upgrades were intended to solve.

local solar adoption because it's typically based on a worst-case scenario in which the solar is producing maximum output at the time of minimum load. Adding EVs and stationary batteries to the DER mix on the circuit, with some operational coordination, provides a means to stay within the safe operating limits of the circuit or transformer while increasing the amount of solar that can be deployed.

A platform for DERs to participate in economic transactions for energy and grid services will stimulate private investment in DERs, because the DER owner will be able to defray their investment cost, or improve their return on investment, by earning revenues through the local DER market. This is a central benefit of the market administration function of the DSO as specified in the Resolve. Absent transaction opportunities, customers must make DER investment decisions based entirely on the expected private benefits, which raises the net cost for the DER owner and deprives the electricity system of the benefits those DERs could provide.

Bulk Power Supply & Resource Adequacy

Resource adequacy planning traditionally focuses on procuring centralized power supply to meet a forecast of peak demand plus a planning reserve margin, to ensure that the bulk system operator always has adequate supply resources to continuously balance supply and demand in real time, to a specified high standard of reliability. DER technologies expand the set of options for meeting the traditional reliability standard. DERs can be aggregated into resources such as VPPs to reduce peak loads, thus reducing the amount of conventional resource adequacy capacity that needs to be procured. DER aggregations can also submit offers to the ISO to be dispatched for system balancing, thus expanding competition in the market for resource adequacy resources.[113] VPPs are aggregations of DERs that provide a variety of utility-grade grid services, including boosting resource adequacy, by orchestrating demand from DERs at flexible times (e.g., EV chargers, water heaters, commercial and industrial loads) or DERs that generate and store electricity (e.g., distributed solar and battery systems). With rapid adoption of distributed energy resources and the need to serve rising peak demand, DERs such as VPPs have the potential to address 10% to 20% of peak demand by 2030 and save approximately $10B per year in grid spending nationally.[114]

Transmission System

The U.S. DOE estimates that, absent a framework to facilitate and utilize VPPs for grid services such as congestion management and peak load reduction, regional transmission capacity would need to increase by 26-119% across U.S. regions by 2035 to meet projected generation and

[113] U.S Department of Energy, The Future of Resource Adequacy at 24. https://www.energy.gov/sites/default/files/2024-04/2024%20The%20Future%20of%20Resource%20Adequacy%20Report.pdf.

[114] U.S Department of Energy, Pathways to Commercial Liftoff: Virtual Power Plants, at 33. https://liftoff.energy.gov/wp-content/uploads/2023/10/LIFTOFF_DOE_VVP_10062023_v4.pdf.

demand growth. At the same time, transmission interconnection backlogs for generation assets have extended the average time spent in queues to five years.[115]

DER aggregations such as VPPs can help overcome transmission congestion challenges, especially in high load conditions, and increase overall grid efficiency by reducing and shifting peak loads. This in turn can help defer or avoid the need to upgrade grid capacity. With a more consistent flow of power, i.e., less extreme peaks at the system level, transmission assets can achieve higher average utilization.

DERs can be deployed as front-of-meter supply resources close to load centers, for example in the form of distributed solar plus storage hybrids situated on existing structures like warehouse roofs, parking lots, and school campuses. By serving local demand these resources avoid any need for transmission upgrades and can be deployed faster and more cost-effectively than transmission-connected generation to accelerate achievement of clean energy targets. A 2016 study by the National Renewable Energy Laboratory (NREL) of the technical potential of solar generation on buildings of all sizes estimated that such deployments could provide 39% of U.S. electricity sales annually and 60% for the state of Maine.[116]

Distribution System

The distribution system is where the three core DSO functions — system operation, market administration and planning — converge to yield cost-reduction benefits over the longer term. In the near term, the functional capabilities needed for operating a high-DER network with high levels of DER participation in transactions will require investment, generally referred to as "grid modernization" and described above in the context of the DSO's operational function. Although grid modernization investments may offset distribution-level DER cost savings initially, these investments are a prerequisite for achieving the longer-term benefits of DERs, including reduced transmission and distribution infrastructure investments, more rapid achievement of state policy goals, and improved system performance, reliability and resilience. Moreover, investments in grid modernization will be required of all distribution utilities that experience DER growth, regardless of whether the state adopts a DSO structure, so these investments should not be viewed as due entirely to DSO implementation.

Once the grid modernization enhancements and the various types of DER economic transactions are implemented, the cost savings on the distribution system come about from accounting for these features in distribution system planning. The section above on planning gets into detail on this point, but the basic idea to reiterate here is as follows. Traditional distribution planning assumes that load is exogenous, i.e., it's a direct expression of the customers' needs for electricity at any

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[115] U.S Department of Energy, Pathways to Commercial Liftoff: Virtual Power Plants, at 12. https://liftoff.energy.gov/wp-content/uploads/2023/10/LIFTOFF_DOE_VVP_10062023_v4.pdf

[116] NREL, 2016, "Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment": https://www.nrel.gov/docs/fy16osti/65298.pdf

given time, and customers don't consider the impacts of their demand on the grid. Moreover, the obligation of the distribution utility is to provide continuous service to all customers up to a high standard of reliability. As a result, planners tend to plan for the most extreme load conditions, with minimal expectation that the load can be modified to mitigate extreme conditions, much less provide flexibility services to support grid operation. The growth of customer DERs, primarily rooftop solar and EVs to begin with, has only exacerbated this problem by introducing new worst-case scenarios for planners to deal with (e.g., all the EV owners on a circuit charging their EVs at the same time during peak load hours). Planning for extreme load conditions and worst-case DER scenarios is a key driver of high infrastructure investment costs.

The cost-saving innovation for distribution planning is to incorporate the impacts of the DSO operational and market enhancements into the planning assessments. In other words, it is no longer appropriate to plan for extreme load conditions and worst-case DER scenarios if the new framework includes sufficient ways to "orchestrate" customer and DER behavior to support reliable system operation. Instead of the pure chaos of individual customers and DERs ignoring grid impacts of their behavior, the interconnection rules will specify the obligations of good grid citizenship, while the economic transactions will, for example, incentivize aggregators to form VPPs to flatten net load profiles at the circuit level, and the grid modernization enhancements will enable the DSO to quickly detect and mitigate real-time problems or even anticipate them. As these and other innovations in the core DSO functions are deployed and mature, distribution planners will be able to rely on them in assessing needs for network upgrades. And when they do identify needed upgrades, they will be able to solicit DER-based "non-wires alternatives" that may be more cost-effective ways to meet the needs and will be confident that these DERs will perform as needed.

6.3 Improved electric system reliability and performance

For today's context of increasing climate volatility and more severe disruptions along with the rapid transitions in energy technologies, discussions of reliability need to distinguish between grid reliability, which is about the performance of the grid, and electric service reliability, which is about the end-use customer experience.

Traditional definitions of reliability tend to focus exclusively on grid reliability. For example, FERC defines grid reliability as follows: Grid reliability is defined as the provision of an adequate, secure, and stable flow of electricity as consumers may need it even during unanticipated disturbances. Specifically, grid reliability is based on two elements:[117]

[117] https://www.ferc.gov/reliability-explainer.

- **Resource adequacy:** Generally speaking, resource adequacy is the ability of the electric system to meet the energy needs of electricity consumers. This means having sufficient generation to meet projected electric demand.

- **Reliable operation:** A reliable power grid has the ability to withstand sudden electric system disturbances that can lead to blackouts.

This definition is, unfortunately, inadequate for today's context because it is entirely grid-centric. It is a legacy of the 20th-century system architecture in which the grid was the only source of electricity for most customers for most of their needs. And it asserts that reliability of service to the end-use customers "even during unanticipated disturbances" can be assured through the two devices of resource adequacy and reliable operation. In the era of worsening climate disruption it is simply inadequate and imprudent to rely entirely on the grid for electric service reliability, and in the era of DER technologies it is not necessary.

Specifically, DERs can improve electric service reliability for electricity end users by being able to provide continuous electricity supply during grid outages. While investments in strengthening or hardening the grid may reduce the likelihood of a grid outage in specific disruption scenarios, and other innovations may reduce the restoration time when outages occur, prudent energy resilience planning for the coming decades requires ensuring continuous electric service for people and communities in the event of grid outages that may last multiple days, especially for disadvantaged and "energy justice" communities, and at a minimum for essential services on which the well-being of each community depends. This requires community-level DERs configured to function as microgrids, to operate independently of the grid when needed.

The trends in climate disruption frequency and intensity, which will get worse long before there are signs of abating, must be seen by planners and policy makers as warnings against relying entirely on the grid for electric service reliability. Indeed, customers with financial resources are already investing in DERs for climate resilience, with little concern for the financial return on investment.[118] Unless the DER policy framework explicitly recognizes the need to provide for energy resilience for all communities, DER-based microgrids will be more widely deployed only by financially capable customers and will become a luxury good that worsens energy inequities.

Returning to the more traditional concept of reliability, hybrid distributed generation and storage resources deployed at various levels of the distribution system, from the T-D interface substation down to intermediate distribution transformers, can enable sections of the system to disconnect and function as multi-customer microgrids when there is an upstream line outage. The hybrid DERs in such scenarios can function as grid-forming resources to energize their local circuits and thereby reduce the number of customers affected by the upstream outage. This type of grid

[118] https://www.microgridknowledge.com/microgrids/commercial/article/11427057/how-microgrids-performed-during-the-summer-heatwave

“sectionalization” is an architectural approach to improve grid reliability and performance that would not be possible without DERs.

Between 2011 and 2021, the average annual number of weather-related power outages in the U.S. increased by roughly 78% compared to 2000-2010. In spring of 2023, the North American Electric Reliability Corporation (NERC) issued its highest alert level ever, urging generation and transmission owners to take measures to prepare for extreme winter conditions, including plans for customer demand management to prevent uncontrolled load shedding and cascading outages. DERs can increase resilience: a geographically diverse footprint of generation sites, a higher number of storage assets, and the ability to ‘island’ sections of the grid into microgrids in response to adverse events such as extreme weather and other threats.[119]

7. Literature Review of DSO Benefits

7.1 Overview

The experience of jurisdictions actively embracing the DSO model, and DER integration provides compelling evidence of the potential for achievable benefits. These benefits have included cost reductions, increased network capacity, reduced curtailment, improved data transparency, and enhanced planning processes. Experience globally has demonstrated that, as the energy transition progresses, the role of DSOs and the effective integration of DER will continue to be an important area of focus for creating a more sustainable, decentralized, and customer-centric energy future.

The UK's experience materially indexes the literature review of DSO benefits, as it reflects one of the more mature DSO implementations and has benefited from the quantification of benefits realized through the early stages of DSO deployments.

Generally, benefits have been realized across the following categories.

Cost Savings. The transition to a DSO model, coupled with DER integration, has demonstrably reduced costs for consumers and network operators. For instance, UK Power Networks realized £199 million in benefits during 2023/24 alone,[120] with projections indicating £1,038 million in savings throughout the RIIO-ED2 regulatory period.[121] Northern Powergrid also documented £1.18 million in savings from deferred network reinforcement attributed to improved asset utilization

[119] U.S Department of Energy, Pathways to Commercial Liftoff: Virtual Power Plants, at 111. https://liftoff.energy.gov/wp-content/uploads/2023/10/LIFTOFF_DOE_VVP_10062023_v4.pdf

[120] UK Power Networks, DSO Performance Panel Report, 2023/24, at 3.

[121] The RIIO-ED2 regulatory period will cover the five-year period from April 1, 2023, to March 31, 2028. UK Power Networks, DSO Performance Panel Report, 2023/24.

facilitated by their DSO activities.[122] These cost reductions primarily stem from the effective procurement and utilization of DER grid services (i.e., flexibility services), enabling the deferral or complete avoidance of traditional utility solution investments.

Increased Network Capacity and Access. DSO initiatives have yielded a notable increase in network capacity, accommodating greater DER penetration and supporting the transition to a low-carbon energy system. UK Power Networks unlocked 4GW of additional capacity through their Technical Limits flexible interconnection initiative and another 1.5 GW through their MW Dispatch project, which supports the wholesale market operator to manage thermal transmission constraints. Furthermore, flexible connection offerings have significantly expedited the connection process for DER, with Northern Powergrid reporting an average lead time reduction of six and a half years.[123] This streamlined connection process is crucial for facilitating the increased deployment of DER, a stated objective of the Resolve.

In Australia, modeling by ITP Renewables suggests that high levels of DER penetration, encompassing flexible demand and battery storage, can substantially lower electricity costs for all consumers.[124] However, the realization of these benefits hinges on effectively addressing existing barriers to DER integration, a common theme across all regions.

Reduced Curtailment and Enhanced DER Utilization. The implementation of innovative DSO solutions, such as data-driven outage management by UK Power Networks, has resulted in a substantial reduction in DER curtailment. This proactive approach led to an 89% decrease in curtailment in 2023/24, enabling generators to operate for extended periods and maximize their low-carbon energy output.[125]

Data Transparency, Accessibility, and Enhanced Planning. DSOs are playing a crucial role in enhancing data transparency and accessibility, empowering stakeholders with the insights needed to actively participate in the evolving energy landscape. Northern Powergrid's Open Data Portal exemplifies this commitment, experiencing a 15x surge in usage, indicating the value of readily available and accessible network data for stakeholders. This data-driven approach extends to planning processes, with DSOs facilitating better-coordinated cross-vector planning initiatives. These initiatives bring together local authorities, gas networks, and other key stakeholders, fostering a more holistic and efficient approach to decarbonization efforts.

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[122] Northern Powergrid, DSO Performance Panel Submission, 2023/24, at 5.
[123] Northern Powergrid, DSO Performance Panel Submission, 2023/24.
[124] Dr Gabrielle Kuiper, Growing the sharing energy economy: How Energy Ministers can support cheaper, faster decarbonisation through distributed energy resources, Institute for Energy Economics and Financial Analysis.
[125] UK Power Networks, DSO Performance Panel Report, 2023/24.

Flexibility Markets and Performance Incentives. The literature review surfaced the pivotal role of flexibility markets in enabling a cost-effective energy transition. The UK's well-established flexibility market serves as a prime example, with distribution networks contracting over 2.4 GW of flexibility services by August 2023.

The success of the UK's approach underscores the significant cost-saving potential of DER grid services as a viable alternative to traditional utility investments.

7.2 UK Case Studies

UK Power Networks

UK Power Networks (UKPN) has shown significant progress in advancing from the traditional Distribution Network Operator (DNO) model to a more dynamic DSO framework. This transition, as reflected in the 2023/24 performance report, has yielded substantial benefits aligned with the broader goals of improving network efficiency, reducing electricity costs, and advancing the UK's net-zero ambitions.

Key benefits realized during this period include £199 million in total, driven by flexibility services and the deferred need for network reinforcement. One of the standout achievements was the deferral of £91 million in distribution network reinforcement costs through the effective use of flexibility services. The DSO awarded over 1.5 GW in flexibility contracts, unlocking more than 4 GW of capacity through the Technical Limits initiative and 1.5 GW through the MW Dispatch service. This flexibility helped achieve a seven-fold increase in flexibility dispatched, reaching 7.8 GWh, which greatly contributed to overall system efficiency.

Environmental impacts were substantial, with the DSO avoiding approximately 7,397 tonnes of carbon emissions. This was largely achieved through the enhanced integration of renewable energy and reduced curtailment of low-carbon generation. UKPN also focused on supporting local authorities by providing tailored tools and access to 52 datasets, which facilitated the development of local decarbonization plans. The DSO's targeted assistance to local authorities has been key to advancing regional energy strategies, accelerating the deployment of distributed energy resources (DER) and supporting local efforts to achieve net-zero objectives.

UKPN's innovative approaches to improving system transparency, such as the release of monthly flexibility dispatch reports and the establishment of an Open Data Portal, allowed for better decision-making and stakeholder engagement. The Open Data Portal saw over 30,000 downloads during the reporting period, further highlighting its role in promoting a data-driven, flexible energy system (UK Power Networks).

The achievements of UK Power Networks in 2023/24 clearly demonstrate its leadership in flexibility markets, cost optimization, and environmental sustainability, setting a high standard for DSO operations in the UK.

Northern Powergrid

Northern Powergrid (NPg) manages the electricity network across the North East, Yorkshire, and Northern Lincolnshire, serving approximately 8 million people. In the 2023/24 reporting period, NPg made significant strides in advancing flexibility, transparency, and stakeholder engagement to support the ongoing transition toward a decentralized and low-carbon energy system. With a focus on increasing the role of DERs, NPg has demonstrated its commitment to improving network efficiency and system reliability, particularly through the integration of flexibility services.

One of NPg's key achievements was the deferral of approximately £1.2 million in network reinforcement costs by leveraging flexibility services, including the management of over 500 MW of flexible connections through Active Network Management (ANM). This milestone underlines the potential of flexibility to postpone costly network upgrades while maintaining system resilience. Additionally, NPg's implementation of low-voltage monitoring, which already reaches 47% of customers on low-voltage circuits, contributed to further improvements in network visibility and efficiency.

NPg has also made impressive progress in data transparency and stakeholder engagement. It has made 56 datasets available through its Open Data Portal, marking a significant increase in accessibility and user engagement, driving a 15x increase in the use of their data. NPg's efforts in enhancing data transparency extend to the development of the Local Authority Portal, which fosters collaboration with local authorities by providing data to aid in energy planning. This effort is further supported by NPg's Regional Insights team, which has engaged with local stakeholders to deliver data and insights that inform decarbonization plans at a community level. The team's involvement has included supporting local councils, such as Newcastle and Bradford, by providing data to guide their local infrastructure and decarbonization strategies.

Through these initiatives, NPg has effectively demonstrated the impact of flexibility services, stakeholder collaboration, and data transparency on enhancing system reliability and supporting the region's transition to a low-carbon future.

SP Energy Networks

SP Energy Networks (SPEN) operates electricity distribution networks in both Central and Southern Scotland and in North Wales, Merseyside, Cheshire, and North Shropshire. SPEN has name numerous achievements in optimizing its network, particularly in integrating flexibility services to enhance grid efficiency and resilience. In the 2023/24 reporting period, SPEN contracted 579 MW of flexibility services, progressing towards its RIIO-ED2 requirement of 1.4 GW. Similar to Northern Power Grid, flexibility services have been leveraged to defer network reinforcement. Six primary reinforcement schemes, which would have cost £18 million, were deferred, saving £4.7 million in the short term and a 45-year NPV benefit of £590,000.

SPEN has also made advances in its monitoring capabilities. In 2023, the company installed approximately 1,400 LV network monitors and developed an Internet of Things (IoT) solution to capture and share data from both the monitors and smart meters. This increased visibility allows SPEN to make more informed operational decisions and improve network reliability, such as the real-time monitoring and proactive management of DERs. SPEN is also working on a real-time network visualization platform to integrate data from various sources, such as smart meters and weather forecasts.

In addition to technical improvements, SPEN has placed significant focus on supporting local decarbonization efforts. The company worked with 22 Scottish local authorities to develop Local Heat and Energy Efficiency Strategies (LHEES) and supported eight Welsh authorities in their Local Area Energy Plans (LAEPs). This proactive approach to stakeholder engagement has helped align regional energy needs with broader decarbonization goals, contributing to over £15 million in economic activity related to electric vehicle charging and heat electrification initiatives should these projects proceed.

Electricity North West Limited

Electricity North West Limited (ENWL) serves over 5 million customers across 2.4 million customer in the North West of England. In the 2023/24 regulatory year, ENWL's DSO activities delivered over £9 million in net benefits. These benefits are primarily derived from enhancements in their LV network monitoring, which now covers approximately 47% of customers on LV circuits. This increased monitoring capability allows for more accurate planning and deferral of network reinforcement projects, resulting in a notable £7.5 million in savings from advanced Distribution Future Electricity Scenarios (DFES) modeling and £1.4 million from LV monitoring improvements.

Looking forward, ENWL expects to deliver additional benefits of over £212 million throughout the RIIO-ED2 period, which spans from 2023 to 2028. These benefits are projected to stem from the continued rollout of enhanced DFES modeling, LV monitoring, and flexibility services. These measures are expected to reduce the need for traditional network reinforcement, thus offering cost savings compared to the conventional DNO model. ENWL's DFES modeling has demonstrated its ability to forecast energy demand and the uptake of low-carbon technologies (LCTs) such as EVs and heat pumps with high accuracy, leading to more informed and cost-effective network planning. ENWL’s accurate forecasting allows for increased adaptivity. For example, there has not been the take-up of LCTs in the North West. ENWL is able to protect value for money for its customers by addressing root causes of low demand and improving market access, rather than investing inflexibility ahead of need,

A critical aspect of ENWL’s DSO strategy is stakeholder engagement, particularly with local authorities. The company has developed personalized consultations to assist in the creation of

Local Area Energy Plans (LAEPs), which align local energy needs with broader decarbonization goals. This approach is further supported by the company's Open Data Portal, where ENWL has made over 50 high-precision datasets and maps available to stakeholders. The data transparency and accessibility provided by this portal enhance decision-making and enable local authorities to develop targeted energy strategies.

ENWL's commitment to flexibility services is another significant component of its DSO program. In 2023/24, the company contracted for a significant volume of flexibility services to support system optimization and defer reinforcement costs. These services are crucial for managing the increasing deployment of low-carbon technologies and distributed energy resources (DERs), ensuring that the grid can accommodate new demands without costly upgrades. Flexibility services not only improve system reliability but also contribute to long-term cost savings, benefiting both ENWL and its customers.

In summary, ENWL's DSO efforts have demonstrated significant financial, environmental, and societal benefits, with ongoing initiatives expected to yield even greater returns throughout the RIIO-ED2 period. The company's focus on advanced modeling, LV monitoring, flexibility services, and stakeholder engagement positions it as a leader in the transition to a smarter, more efficient, and decarbonized energy system.

8. Maine Context + Comparison

It is important to recognize that Maine's distribution utilities and other entities are currently evolving their grid functions and making investments that have relevance to some aims of the Resolve. That said, there may be some aspects of grid functions as they stand in Maine today that are not to the same maturity or sophistication as DSO functions as defined by the Resolve, as articulated in Section V above, or advanced grid functions implemented through other DSO initiatives globally. This comparative analysis seeks to identify any potential gaps or opportunities for the evolution of grid functions toward those that can support the achievement of the Resolve's objectives.

Specifically, DSO functions are compared to current Maine grid functions to examine the following: How do well-designed DSO functions differ from current-state Maine grid functions? To what extent do grid functions in Maine already perform or plan to perform these more advanced functions?

This comparative analysis serves as an initial review of Maine's distribution utilities grid functions, is not exhaustive in nature and is based on a limited set of information sources including written responses from CMP, the EPE report and the recent Maine PUC grid planning order. Moreover, this analysis is solely focused on each of the investor owned utilities (IOUs), Central Maine Power (CMP) and Versant Power. The report recommends that a more detailed analysis be conducted in collaboration with the distribution utilities in subsequent processes if Part 2 of the study moves forward. We note that CMP did provide written responses which are referenced throughout this analysis.

Below we walk through each DSO function and compile evidence on whether one or both IOUs as well as other entities have or are planning to conduct activities related to each DSO function.

8.1 System Operations

8.1.1 Flexible Connections

Both IOUs

Neither IOU has implemented flexible interconnection to date but there is momentum to further investigate the opportunity. On May 24, 2024, GEO partnered with CMP and Versant to submit a full application titled "Flexible Interconnections and Resilience for Maine" (FIRM) through the DOE – BIL – Grid Resilience and Innovation Partnerships, which included, among other projects, the request for grant funding to implement Active Network Management (ANM) in the Company's service territory. On October 18, 2024, GEO announced it had been selected to receive a $65 million grant for new technologies to enhance electrical grid planning and operation in Maine.[126]

CMP states the primary use case for flexible interconnection is addressing constraints. By addressing constraints, flexible interconnection can enable a secondary use case by increasing hosting capacity, which would increase system utilization. Moreover, they state that the implementation of ANM would also allow greater visibility and control within the system, enabling greater utilization of the system. Finally, CMP states that leveraging flexible interconnection could reduce the time to interconnection compared to traditional 'wires' solutions, such as additional substation capacity.[127]

CMP

In addition to the flexible interconnection federal proposal described above, CMP plans on a limited DER control approach which would entail manual curtailment requiring employee interaction for a limited number of interconnections. The Company believes manual curtailment is not a viable, scalable solution to ensure the safe, reliable operation of the electric system, and an automated real-time solution would be required if flexibility is to be offered.[128]

[126] State of Maine, Governor's Energy Office, "Press Release: Maine Governor's Energy Office Announces $65 Million Federal Grant to Prepare the Electrical Grid for More Renewable Energy," October 18, 2024, *available at* https://www.maine.gov/energy/press-releases-firm-grant-announcement-oct-2024.

[127] Central Maine Power, DSO Study Comments, August 8, 2024, at 5.

[128] Central Maine Power, DSO Study Comments, August 8, 2024, at 5.

8.1.2 Grid Services Dispatch

CMP

CMP intends to use these advanced technologies to allow for flexible renewable interconnections and avoid costly network upgrades. In addition, this technology will enable CMP to potentially offer additional alternative rate options to facilitate load shifts from peak to non-peak hours. CMP states this will allow them to increase grid utilization and efficiency while allowing more DERs and other customers to come online in a cost-effective manner.[129]

Efficiency Maine Trust

EMT operates a comprehensive demand management program[130] that dispatches DERs based ISO-NE system peaks. This includes programs for small battery management, large battery management, commercial curtailment and managed charging for EVs.

8.1.3 Operational Network Visibility

CMP

CMP states accurate data is essential for electric utilities to ensure grid reliability, optimize operations, and make informed infrastructure investments. Moreover, CMP states as the grid becomes more complex with the integration of renewable energy, smart technologies, and increased demand, the need for precise and comprehensive data is only growing.

CMP has several ongoing initiatives to improve data quality. First, CMP has the Grid Model Enhancement Project (GMEP), a holistic distribution system field survey project that will verify field data and ensure the ongoing accuracy of the Company's GIS and SAP databases. This project will also recommend process improvements to allow this data to retain a state of high quality. Second, CMP has a distribution automation project that annually installs hundreds of Supervisory Control and Data Acquisition (SCADA) devices in the field. This can enable better data quality, which the planners will utilize when allocating Cyme models. Third, CMP also has a CYME Server initiative to streamline traditional and time series studies and facilitate the initial stages of automating hosting capacity map updates with targeted line sensors being deployed to close any data gaps they currently have in the field. Finally, the Company has an initiative in place to bring AMI meter data into the Cyme model, which will allow for enhanced distribution system analyses, such as time-series analyses.[131]

Versant Power

Versant has proposed in its 2024-2028 technology roadmap to implement an ADMS-SCADA implementation. As of the 2021 Electric Power Engineers (EPE) Distribution Utility Examination, Versant had SCADA equipment at 73 of 78 substations.

[129] Central Maine Power, DSO Study Comments, August 8, 2024, at 11.
[130] https://www.efficiencymaine.com/demand-management/about/
[131] Central Maine Power, DSO Study Comments, August 8, 2024, at 5.

8.1.4 DER Orchestration

CMP

CMP does not appear to have a holistic DER orchestration plan but does utilize and plans to utilize various DER orchestration approaches.

CMP does not directly communicate with DERs today for control. For certain DERs, communications between the Company and the DER exist to allow for the transfer of telemetry data and control of the high-side interrupting device in the event of an outage or system emergency. CMP is actively pursuing advanced technologies through several different avenues, such as active network management and DERMS, to enable direct communication with DERs to allow for flexible interconnection and to increase system utilization.

Moreover, CMP currently uses smart inverters' capability to help control local voltage levels on the distribution system. In addition, they are utilized for mitigation to address system constraints and avoid costly upgrades identified during an interconnection distribution system impact study (SIS). CMP utilizes the capabilities of smart inverters through fixed power factor mode and Volt-VAR mode. CMP coordinates closely with ISO New England to review all proposed generation projects greater than 1 MW, as drivers on the bulk electric system may also require the generator to operate in Volt-VAR mode. CMP intends to consider volt-watt as a possible control strategy for smart inverters in future planning assessments.

Versant Power

Versant has proposed in its 2024-2028 technology roadmap to implement ADMS - Advanced Apps & DERMS Implementation. Moreover, Versant requires IEEE Std 1547-2018 (2nd ed.) smart inverters.

Efficiency Maine Trust

EMT currently leverages a DERMS platform provided by Virtual Peaker which allows EMT to notify participants of impending demand response events, control the load of the DER during events, track performance across demand response events and issue incentives.[132]

Both IOUs

The Maine PUC has ordered both utilities to include information regarding technology, integration, and systems investments that support state climate and clean energy goals in their grid plan.[133] This includes Advanced Distribution Management System (ADMS) and Distributed Energy Resource Management Systems (DERMS) vision, plans, evaluation, and compatibility or synergies with third-party entities (e.g., Efficiency Maine Trust).[134]

[132] https://www.efficiencymaine.com/demand-management/residential-ev-managed-charging/

[133] Maine PUC, Proceeding to Identify Priorities for Grid Plan Filings, Order, July 12, 2024, at 21.

[134] Maine PUC, Proceeding to Identify Priorities for Grid Plan Filings, Grid Content Outline, July 12, 2024.

8.2 DER Markets

8.2.1 Grid Services Valuation Framework

A DER distribution grid services valuation framework has not formally been developed yet. However, EMT does include the *Avoided Energy Supply Components in New England* report[135] as part of its Triennial Plan[136] each year, which includes an estimated value for avoided distribution costs. This could be used as a starting point to develop this framework.

8.2.2 Distribution Market Design

A formal DER market design framework has not been developed in Maine to procure and dispatch DER grid services.

8.2.3 Market Operations

A formal DER market operations framework has not been developed in Maine to procure and dispatch DER grid services.

8.3 Integrated System Planning

8.3.1 Planning Network Visibility

CMP

CMP states accurate data is essential for electric utilities to ensure grid reliability, optimize operations, and make informed infrastructure investments. Moreover, CMP states as the grid becomes more complex with the integration of renewable energy, smart technologies, and increased demand, the need for precise and comprehensive data is only growing.

CMP has several ongoing initiatives to improve data quality. First, CMP has the Grid Model Enhancement Project (GMEP) which is a holistic distribution system field survey project that will verify field data and ensure the ongoing accuracy of the Company's GIS and SAP databases. This project will also recommend process improvements such that it will allow this data to retain a state of high quality. Second, CMP has a distribution automation project which involves installing hundreds of Supervisory Control and Data Acquisition (SCADA) devices in the field annually. Which can enable better data quality, that the planners will be able to utilize when allocating Cyme models. Third, CMP also has a CYME Server initiative to streamline traditional and time series studies and facilitate the initial stages of automating hosting capacity map updates with targeted line sensors being deployed to close any data gaps they currently have in the field. Finally, the

[135] https://www.synapse-energy.com/sites/default/files/inline-images/AESC%202024%20May%202024.pdf

[136] https://www.efficiencymaine.com/triennial-plan-vi/

Company has an initiative in place to bring in advanced metering infrastructure (AMI) meter data into the Cyme model which will allow for enhanced distribution system analyses, such as time-series analyses.[137]

Versant Power

Versant Power is in the progress of deploying advanced metering infrastructure (AMI).[138]

Both IOUs

The Maine PUC also ordered both IOUs to include a narrative and a proposed roadmap within its grid plans, identifying the near-term actions and investments, timeframes and costs needed to make this shift to time series analysis.[139]

8.3.2 Enhanced forecasting, simulation & modeling

CMP

CMP states its load forecasts incorporate DER and beneficial electrification adoption rates consistent with the ISO-NE CELT forecast assumptions, which are based on Maine's climate and energy goals and targets. These forecasts are then utilized directly in the system planning process to establish and support CMP's investment plans.

Load forecasts are currently prepared at the corporate (CMP) level and then disaggregated top-down/across the CMP service centers. Additionally, beneficial electrification and DERs are mapped by location and are the foundation for a complementary bottom-up forecast that informs disaggregation of the corporate-level forecasts. CMP is currently developing a more robust bottom-up process to generate forecasts by distribution substation and, ultimately, by distribution feeder.

To some extent, CMP plans to incorporate load management into its forecasts. The Company incorporates load management from Efficiency Maine Trust (EMT)'s programs into its forecasts insomuch as the demand response impacts are embedded in the historical sample used to estimate the model. Moreover, CMP is pursuing in front of the meter load management and demand response through pilot projects and programs can be accounted for in CMP's load forecasts once these pilot projects are in-service and more data is available.[140]

Both IOUs

The Maine PUC also ordered the utilities must use two different forecasts in their grid plans, each derived from the most recent CELT (i.e., the 2024 CELT released May 1, 2024), the 50/50 weather

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[137] Central Maine Power, DSO Study Comments, August 8, 2024, at 5.
[138] https://www.versantpower.com/energy-solutions/newmeters.
[139] Maine PUC, Proceeding to Identify Priorities for Grid Plan Filings, Order, July 12, 2024, at 21.
[140] Central Maine Power, DSO Study Comments, August 8, 2024, at 5.

year and the 90/10 weather year, and consider six different seasonal load snapshots of each forecast.[141]

8.3.3 Holistic and competitive solution vetting process

CMP

The Company states it continues to develop a comprehensive approach to considering non-wires alternatives in its system planning process and that it conducts internal screens of every planned transmission and distribution project to determine the viability of potential NWA solutions.[142]

Both IOUs

Moreover, MRSA §3132 and §3132-D[143] established a non-wires alternative process that includes the creation of a non-wires alternative coordinator (NWAC) under the Office of the Public Advocate.

The process is as follows:

- The NWAC is required conduct an investigation of and make recommendations regarding nonwires alternatives to a wires project in coordination with Efficiency Maine Trust.
- The investigation must include a benefit-cost analysis that evaluates the cost-effectiveness of nonwires alternatives as compared to the wires project.
- An investor-owned transmission and distribution utility shall provide data requested by the Public Advocate or the Efficiency Maine Trust, subject to enforcement by the commission, to allow the nonwires alternative coordinator, in conjunction with the trust, to carry out investigation and analysis
- On the basis of the investigation under subsection 1, the nonwires alternative coordinator shall develop and provide to the commission or to an investor-owned transmission and distribution utility, as appropriate, recommendations regarding cost-effective nonwires alternatives to the wires project, including a proposed plan for procurement of the recommended nonwires alternatives

The NWAC and the IOUs came to an agreement on an NWA process.[144] A snapshot of which is provided below.

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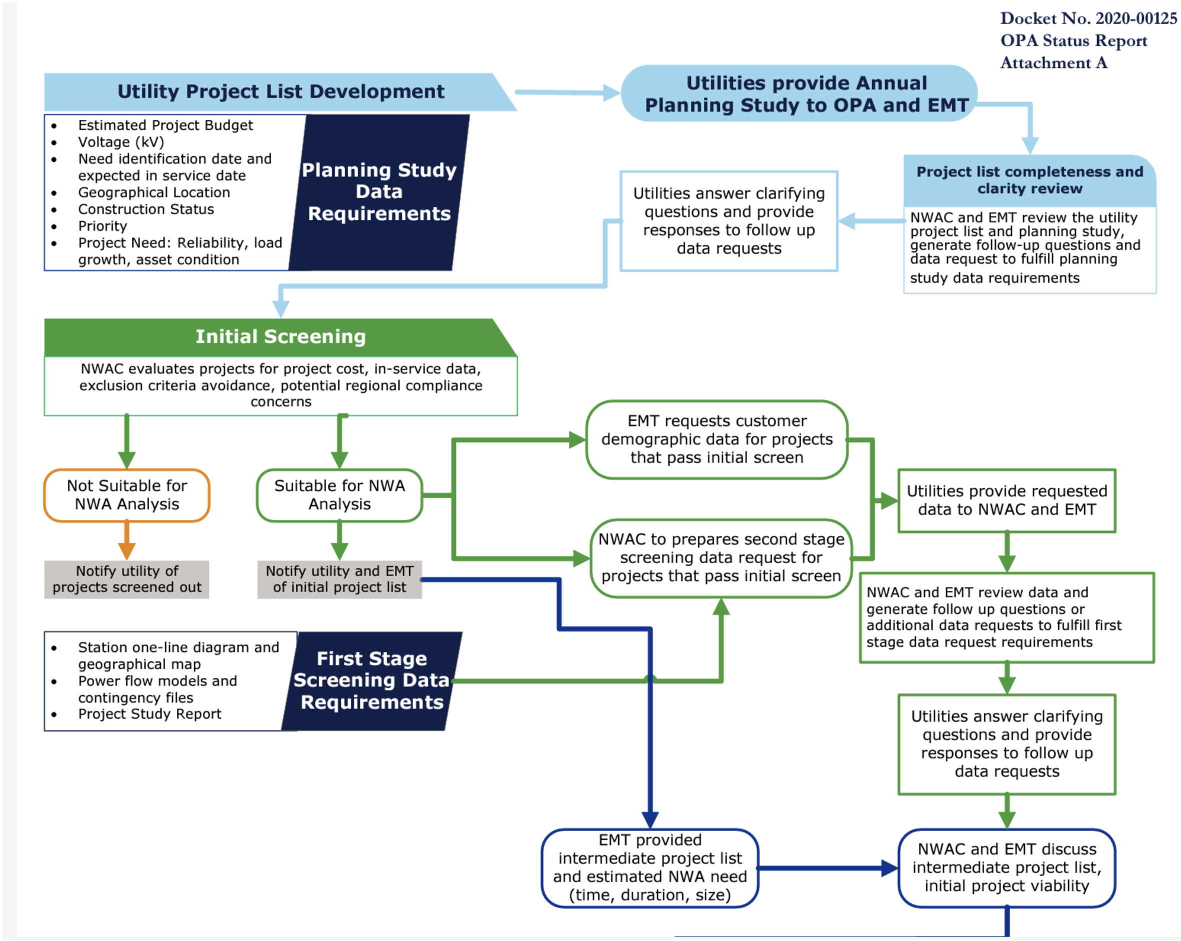
[141] Maine PUC, Proceeding to Identify Priorities for Grid Plan Filings, Order, July 12, 2024, at 26.

[142] Central Maine Power, DSO Study Comments, August 8, 2024, at 6.

[143] https://www.mainelegislature.org/legis/statutes/35-A/title35-Asec3132-C.html.

[144] https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/ViewDoc.aspx?DocRefId={32A79CF8-26E3-486C-9A3A-D19C9376E13B}&DocExt=pdf&DocName={32A79CF8-26E3-486C-9A3A-D19C9376E13B}.pdf.



To date, it is our understanding that the NWAC has only worked with CMP on screening and identifying potential NWAs. The NWAC and CMP recently came to a memorandum of understanding (MOU)[145] that identifies with specificity, certain factors which will apply to the NWA analysis so that the NWA reviews are consistent and efficient. However, it is our understanding that a NWA has yet to be procured or implemented.

The Maine PUC's recent grid plan order also emphasizes roles for third-party stakeholders in the Grid Needs Assessment and Grid Plan as part of its broader vision for the grid plans. Specifically, the PUC requires stakeholder meetings at three milestones in the development of the grid plan: (1) when the utilities have the inputs to run the models, (2) when the needs assessment is complete and (3) when potential solutions have been identified.[146] Moreover the Maine PUC ordered to the use of a scorecard to serve as a common format for solutions evaluation to be shared across utilities, projects, and grid plans.[147]

[145] https://mpuc-cms.maine.gov/CQM.Public.WebUI/Common/ViewDoc.aspx?DocRefId={EA5F597C-BCD8-4FD1-AD6F-4D4392D0EEE6}&DocExt=pdf&DocName={EA5F597C-BCD8-4FD1-AD6F-4D4392D0EEE6}.pdf.

[146] Maine PUC, Proceeding to Identify Priorities for Grid Plan Filings, Order, July 12, 2024.

[147] Maine PUC, Proceeding to Identify Priorities for Grid Plan Filings, Order, July 12, 2024, at 30.

CMP

CMP currently provides customer data to individual customers via its Energy Manager tool through which customers can download up to 13 months of historical hourly electricity usage data in .csv format for their own analysis or in .xml format to be used with Green Button apps.[148] CMP does not appear to have functionality for customers to authorize third parties to access their data in a digitized manner.

CMP currently provides system data via its hosting capacity maps, of which the generation maps are updated quarterly (targets monthly updates for select circuits) and the load maps are updated annually.[149] CMP does not appear to have functionality within these maps to download or use an API to pull large amounts of data.

CMP currency receives DER data via a requirement for all DERs greater than 1MW to have SCADA at the customer-owned recloser and to provide data and control to the utility through this recloser. The hourly data that is currently collected at this device is real power, reactive power, voltage, open/closed status, and remote/local status of the generator recloser. The Company is looking to increase this requirement to DERs larger than 500kW in the next revision of the Companies' Transmission and Distribution Interconnection Requirements for Generation document. CMP states this data is used when monitoring circuit and substation peaks throughout the year. CMP aligns this hourly DER data with the hourly SCADA data at the circuit head end to determine the generation impacts on circuit loading throughout the day. Due to the size of these DERs, CMP states it is vital to know their impact and contribution to the Company's net power flow of the Distribution circuit, allowing CMP to use the correct data in distribution models for analyses. Finally, CMP states knowing precisely what the DER is outputting enables the Company to plan the system properly and to propose capital projects to improve the system as needed.[150]

Versant Power

Versant currently provides system data via its hosting capacity maps which appear to only provide data for generation.

Both IOUs

The Maine PUC ordered both utilities to provide a baseline amount of data as part of their grid plans, including (1) transmission and distribution system data, (2) financial data, and (3) DER deployment data.[151]

[148] https://www.cmpco.com/smartenergy/understandyourusage/downloadusagedata.
[149] Central Maine Power, DSO Study Comments, August 8, 2024, at 15.
[150] Central Maine Power, DSO Study Comments, August 8, 2024, at 16.
[151] Maine PUC, Proceeding to Identify Priorities for Grid Plan Filings, Grid Content Outline, July 12, 2024.

9. Findings + Recommendations

This Report has been developed in accordance with the Resolve, which instructed the GEO to select a third-party consultant to conduct a two-part study on the establishment of a Distributed System Operator (DSO). This document represents the Initial Study as outlined by the Resolve and offers high-level guidance for DSO Study Part 2, should the GEO decide to move forward.

The Resolve directs the Initial Study to assess whether a DSO can be designed to achieve the following objectives:

- Demonstrably reduce electricity costs for customers;
- Improve the reliability and performance of the electric system in the State;
- Accelerate the achievement of the State's climate goals and promote the growth of distributed energy resources.

If the consultant's Initial Study concludes that it is feasible to design a DSO that meets these three objectives, and the GEO agrees with this conclusion after reviewing and evaluating the Initial Study, the GEO will authorize the consultant to proceed with the second part of the study.

To comply with the direction outlined in the Resolve and drawing from international precedents, the Initial Study explores whether the functions specified for the Distributed System Operator (DSO), if effectively implemented, can support cost-effective integration of Distributed Energy Resources (DER) and promote further growth of DER in a way that aligns with the objectives stated in the Resolve, regardless of the specific design structure of the DSO.

9.1 DSO Grid Functions

Informed by the experience of leading jurisdictions globally and early learnings within Maine as it continues along its energy transition, there is a significant need to expand and enhance the traditional grid functions performed by a distribution utility to meet the needs of a renewable and distributed future grid.

System Operations
In a high-DER electricity system, the core objectives of distribution system operations will need to expand to include integrating DERs into the system and facilitating their participation in a way that can unlock and utilize their maximum potential benefits. Enhancing the current approach to system operations will necessarily include the development of new and expanded capabilities.

As demonstrated across many global examples, distribution utilities will increasingly need to develop options for the *flexible connections* of DER to integrate more DER and at lower cost than under traditional interconnection approaches. The operations function will also need to define grid services in a technology-neutral manner and enable the dynamic dispatch of DER. Further, the operation of a distribution network populated by millions of dispatchable DER assets will require enhanced operational visibility for short-term forecasting and real-time monitoring of the system and grid-connected assets.

Integrated System Planning

This report examines the evolving approach to electricity system planning, traditionally segmented into resource, transmission, and distribution planning. Historically, these functions operated in siloes with limited interaction, reflecting a top-down, centralized model where most energy resources are connected to the bulk transmission system. This approach sufficed for the stable demand growth and one-way distribution flow characteristic of the 20th century. However, it falls short in accommodating the rise of distributed energy resources (DERs) like solar photovoltaics, electric vehicles (EVs), and batteries, which require integration at the distribution level. DERs, often located close to load centers, offer substantial benefits by reducing the need for costly transmission upgrades, minimizing system losses, and providing grid services to manage localized constraints.

The report finds that the future electricity system will need to evolve toward a bottom-up planning approach that leverages granular data from DERs to better integrate them into the grid. Unlike the traditional top-down model, which starts with broad load growth forecasts and assumes large-scale resources on the transmission system, bottom-up planning emphasizes deploying resources closer to demand centers. This approach involves collaboration with city planners and local entities, expanding the scope of resource planning to include potential project sites within communities and aiming to meet local energy needs more cost-effectively. Such coordination promises broader benefits, from climate resilience and economic growth to improved community health and system reliability, enhancing the responsiveness and sustainability of electricity systems.

DER Market Administration

This report explores the economic mechanisms available for distributed energy resources (DERs) and DER aggregations (DERAs) to engage in revenue-generating transactions that provide value beyond the immediate benefits to end-users who install them. A wide array of transactions, from net energy metering and utility grid-service tariffs to power purchase agreements (PPAs) and competitive auction markets, form the ecosystem where DERs can participate. The aim is to enable DERs to contribute to the broader electricity system while being financially incentivized to enhance their operational value, ultimately maximizing the societal and economic return on DER investments.

A core focus of the report is the role of administering a market platform for DERs at the distribution level, which would manage all relevant transactions, performance requirements, and operational impacts. Such a platform allows for the tracking of DER activities in real-time, ensuring that these resources align with system reliability needs and providing a historical record for planning. The role spans from pre-qualifying DERs for services, ensuring compliance with performance metrics, and financially settling transactions. This DSO-administered market must integrate DER economic incentives with grid reliability goals, linking system needs with market activities to avoid infrastructure upgrades while enhancing DER deployment.

Additionally, the report discusses the integration of market operations with traditional grid functions, such as planning and coordination with bulk system markets, and outlines the importance of supporting various DER transactions, from customer-sited exports to complex peer-to-peer and local auction markets. To fully harness DER potential, the DSO must be prepared for service "stacking," where DERs provide multiple services concurrently, as well as managing distribution impacts on bulk system transactions. This integrated approach underscores the need for cohesive market design and collaboration with stakeholders to promote a resilient, decentralized energy future.

9.2 Supporting the Resolve's Objectives

The report analyzes whether a distribution system framework, based on DSO Grid Functions outlined in the Resolve, can more effectively meet the Resolve's objectives. Specifically, it focuses on integrating and utilizing DERs to help Maine achieve its climate goals. The aim is to enhance cost savings, as well as improve the performance and reliability of both distribution and transmission systems.

9.2.1 Accelerating the achievement of the State's climate goals

This report highlights how the traditional electricity system, built for one-way energy delivery from centralized supply sources through transmission to consumers, is evolving in response to significant shifts in energy demand and supply. Historically, long-term forecasts and centralized generation planning met steady demand growth with limited local generation and a distribution system designed primarily for one-way energy flow. However, today's climate goals and the rapid expansion of renewable energy sources are testing the limitations of this model. Renewable projects are increasing at a pace that strains transmission planning and interconnection processes, often in remote areas lacking transmission access, which complicates reliance solely on bulk-system resources to achieve clean energy targets.

Additionally, the shift toward electrification of transportation, buildings, and data-intensive industries is leading to unprecedented load growth, suggesting that a distributed supply model could more reliably and quickly meet rising demand while advancing climate goals. DERs offer scalable, cost-effective, and rapidly deployable alternatives to bulk generation by locating supply closer to consumption points, reducing dependency on new transmission infrastructure. Technologies such as virtual power plants (VPPs) also enable quicker deployment and operational flexibility. Furthermore, electrification solutions like electric vehicles, smart water heaters, and heat pumps not only reduce fossil fuel use but also function as DERs, adding flexibility and resilience to the grid.

Overall, the report underscores that DERs have become crucial to balancing grid demands, mitigating bulk-system limitations, and accelerating climate targets, making it increasingly essential to incorporate distributed resources in state energy planning. These resources, which both generate and manage energy locally, represent a resilient and feasible path to achieving the State's renewable energy goals within the timelines required for effective climate action.

9.2.2 Demonstrable reduction in electricity costs for customers

This report explores how DERs can contribute to reduced electricity costs and offer a viable alternative to traditional, transmission-heavy strategies for achieving state policy targets. By placing distributed generation and storage closer to demand centers, DERs help decrease transmission reliance, presenting cost savings by reducing infrastructure needs for peak-load transmission and distribution upgrades. In this model, DERs help flatten load profiles, increasing grid hosting capacity and enabling higher levels of local renewable generation, such as rooftop solar, without requiring additional infrastructure expansion.

Furthermore, DERs enable a more flexible and economically efficient energy market by allowing these resources to participate in grid services transactions. Virtual Power Plants (VPPs), for instance, aggregate DERs to meet peak demand and resource adequacy requirements, enhancing grid reliability and reducing bulk system dependency. VPPs help alleviate transmission congestion, optimize asset utilization, and support clean energy targets by providing reliable local power solutions. They also open pathways for private investment in DERs, as the market incentives for DER transactions enhance returns on DER investments and lower customer costs.

Lastly, the report emphasizes the need for grid modernization to support the high-penetration DER framework. Investments in modernizing the distribution system will enable optimized DER coordination, ensure efficient operation, and achieve cost savings over time by allowing DERs to function as "non-wires alternatives" in distribution planning. As DER-based solutions mature and become operational, they will increasingly support distribution system resilience, reduce the need for costly infrastructure upgrades, and improve overall grid performance. This shift is critical to creating a robust, DER-integrated grid capable of meeting climate goals cost-effectively.

9.2.3 Improved electric system reliability and performance

This report highlights the need to redefine reliability in the context of modern energy challenges, including increasing climate disruptions and evolving energy technology. Traditionally, grid reliability focused exclusively on ensuring stable electricity flow through resource adequacy and reliable operation, which was sufficient in the 20th-century grid architecture where the grid was the sole source of electricity for most customers. However, in today's era, where Distributed Energy Resources (DERs) are widely available and climate-related threats are more severe, this grid-only approach to reliability is inadequate for ensuring continuous electric service, especially during prolonged grid outages caused by extreme weather events.

DERs present a valuable alternative by enhancing electric service reliability, especially for end users and critical community services. DER-based microgrids, capable of operating independently during outages, can sustain essential services even during prolonged disruptions, providing a resilient energy solution that is increasingly crucial for disadvantaged and energy-vulnerable communities. This community-level resilience is especially important as wealthy customers are already turning to DERs for reliability, risking increased energy inequities if DER resilience remains accessible primarily to those with financial means. A policy framework that enables DERs for all communities is essential to equitable climate resilience.

In addition to enhancing service reliability, DERs offer new methods to improve traditional grid reliability through sectionalization. When deployed as hybrid generation and storage resources at key points in the distribution system, DERs enable sections of the grid to form multi-customer microgrids and operate independently during upstream outages, reducing the scale of disruptions. As weather-related outages increase and climate disruptions worsen, DERs offer a critical pathway to bolster grid resilience, improve restoration capabilities, and maintain consistent power flow for both individual customers and entire communities.

9.3 Conclusion

The Resolve directs the Initial Study to assess whether a DSO can be designed to achieve the Resolve's objectives. To answer this question, the Initial Study has abstracted away inherent complexities related to the structural design of a DSO and simply defined a DSO for Initial Study purposes as the embodiment of the DSO Grid Functions, well-designed and implemented.

Having examined the importance of expanded and enhanced distribution grid functions to the integration and utilization of DER as well as the vital link between DER integration and the achievement of the Resolve's objectives, this Initial Study concludes the following:

A DSO – defined by the embodiment of advanced DSO Grid Functions – can be designed to achieve the Resolve's objectives.

10. DSO Study Part 2 - Suggested Approach

Should GEO decide to proceed with Part 2 of the DSO feasibility study, this report recommends that the focus reflect the elements specified in Resolve Section 3 for a DSO design proposal. The Resolve expresses multiple objectives for this work, which can be summed up as a study of the functional requirements and role assignments to implement advanced distribution grid functions in Maine's electricity system in a manner that supports State energy goals, including cost control, improved system reliability, and greenhouse gas reductions. This report suggests that a Part 2 Study be guided by the objectives of the Resolve and aim to present a decision-oriented set of options that the State of Maine could consider in its ongoing electricity market policymaking. The authors propose to apply insights from Part 1, the initial study, including DSO Grid Function descriptions, technical research, conceptual frameworks, and experience of peer jurisdictions, to identify high-yield opportunities and actionable strategies to enhance foundations for DER integration and orchestration for the state.

This report proposes a Part 2 study that builds upon the efforts in Part 1 to identify opportunities to enhance distribution grid functions over time in relation to increasing levels of DER deployment. A Part 2 study would also explore a range of structural approaches — including both DSO functional design options and possibilities for situating the enhanced DSO Grid Functions within Maine's existing industry structure — that could be incorporated into a prospective DSO (or DSOs) for Maine. Such an examination would consider global lessons learned and the unique characteristics of Maine's electricity system and current market structure.

The primary objectives of the Part 2 study would be to:

- Explore conceptual DSO structures and evaluate the potential challenges and benefits associated with different approaches, informed by real-world complexities inherent in Maine's current electricity system. If Maine policymakers choose to continue a DSO examination following the completion of Part 2, this discussion would provide a constructive foundation for further stakeholder process and investigation.

- Outline a phased roadmap of activities for implementing enhanced distribution grid functions, beginning with near-term actions to meet the needs of Maine's electricity system today, with a vision towards subsequent activities that are needed to unlock the greatest benefits of a high-DER future system.

Exploring the future functions of Maine's distribution system is essential to advancing the state's policy objectives while reducing costs. As Maine transitions to a cleaner, more distributed energy landscape, effective DER integration will be vital to achieving climate goals, enhancing system reliability and resilience, and meeting growing energy demands. A modernized distribution system that supports flexible DER connections, bottom-up energy planning, and grid service-based DER market mechanisms will enable Maine to right-size infrastructure investment, reduce grid congestion, and improve reliability for all customers. By evolving toward a more adaptable and efficient high-DER grid, Maine can expand renewable energy access while limiting the need for costly utility-scale investments and create a more resilient energy system that benefits all consumers and communities.