Distribution Grid Code Adoption Pathways

June 2024

U.S. DEPARTMENT OF ENERGY | OFFICE OF ELECTRICITY

Disclaimer

Acknowledgments

This work was prepared by Surhud Vaidya and Rosalie Yu of ICF, and Paul De Martini of Newport Consulting Group. The paper benefited from feedback by Jim Ogle of Pacific Northwest National Laboratory, Ben Ealey of the Electric Power Research Institute, and the Distribution Grid Transformation Industry Working Group.

The U.S. Department of Energy's Office of Electricity sponsored this report as part of a broader ongoing effort to advance market and operational coordination of distributed energy resources, especially their evolving use as virtual power plants. The Office of Electricity's Program Manager Joseph Paladino oversees this work.

Contents

Introduction

The integration of distributed energy resources (DERs) is being pursued on a broad scale in the United States to bring several benefits to customers and society. These benefits include demand flexibility, lower emissions of greenhouse gases (GHGs) and pollutants, increased customer choice, reduced electricity bills, and reliability and resilience services. Some states and jurisdictions have taken a leading role in this transformation by developing forward-looking objectives and policies for DER utilization. However, for states that are just familiarizing themselves with this topic, there is a lack of understanding of the interrelated considerations that facilitate DER integration and utilization. This lack of understanding extends to issues relevant to areas such as distribution planning, data sharing and communication, distribution operations, and DER interconnection, among others.

The U.S. Department of Energy (DOE) has initiated a series of papers on distribution grid codes to build a knowledge base relevant to the topic of attainment of the objectives associated with DER integration and utilization, and to advance an understanding of the related technical, business, and institutional considerations.[1] The first paper in this series, titled "Distribution Grid Code Framework," presented a structure and framework to enunciate the interrelated considerations.[2]

This document builds on that foundation to describe how utilities and regulators can utilize the distribution grid code framework to create pathways for the adoption of incremental functionalities and capabilities that aid the attainment of DER integration and utilization goals. To do so, the paper expands on the concept of a distribution grid code adoption pathways matrix briefly introduced in the first paper. The matrix is a tool for practitioners to use in conjunction with the distribution grid code framework to determine the incremental capabilities and functions to be procured as DER penetration rises. The matrix includes dimensions relevant to the number of customers being served by an electric distribution system, as well as metrics relevant to DER adoption and use. By understanding their relative position in the matrix (as a function of the number of customers and DER adoption and use), practitioners can create roadmaps for DER integration and utilization based on their jurisdictional goals and objectives.

In combination, the distribution grid code framework and adoption pathways matrix provide practitioners with a foundation and actionable steps for advancing DER integration and utilization activities based on jurisdictional regulatory policy objectives and customer needs.

The Necessity for Grid Codes

As mentioned previously, DERs have the potential to provide several customer benefits, while also resulting in impacts on the electrical distribution system. Recognizing this fact, various entities have commenced initiatives to address DER integration issues. These include, but are not limited to, the Federal Energy Regulatory Commission's passage of Order 2222, the National Association of Regulatory Utility

---

[1] In this context, "distribution grid codes" refer to the intertwined technical, business, and institutional practices and considerations required to integrate and utilize DERs within power systems.

[2] The distribution grid code framework was introduced in a prior DOE paper. See DOE, Distribution Grid Code Framework, November 2023. Available online at https://www.energy.gov/sites/default/files/2023-11/2023-11-15%20Distribution%20Grid%20Code%20Framework_optimized.pdf

Commissioners (NARUC) and National Association of State Energy Officials Task Force on Comprehensive Electricity Planning, California's High DER Future Grid Proceeding, and the State of New York's Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision.[3, 4, 5, 6] However, these initiatives tend to be limited in their geographical scope and often reflect very narrow jurisdictional objectives. If DER deployment is to rise to the levels envisioned by publications such as DOE's Virtual Power Plant (VPP) report (80 to 160 gigawatts of VPPs deployed by 2030) and aid in meeting national clean energy goals (reduce GHG emissions 50% to 52% below 2005 levels in 2030, reach 100% carbon pollution-free electricity by 2035), standardized processes for grid planning and DER integration are required.[7, 8] The lack of standardized DER integration and utilization practices and communication and coordination mechanisms may lead to suboptimal and inefficient processes and increased timelines for DER interconnection and electrification. The lack of uniform practices also may lead to confusion and increased costs for utilities, developers, and device manufacturers that provide the equipment for this transition, who may need to grapple with varying standards and terminology across regions.

The distribution grid code framework and other DOE reports aim to address these issues.[9] Specifically, the distribution grid code framework is envisioned to assist stakeholders in the following manner:

- Provide a unified framework, vocabulary, and vision related to DER integration and utilization across jurisdictions.
- Assist in building an understanding of the various interrelated technical, business, and institutional considerations, including improved system planning, data sharing, the use of DER services, and operational coordination, among other aspects.

---

[3] Federal Register. 2020. Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators, Order No. 2222, 172 Federal Energy Regulatory Commission 61,247. https://www.ferc.gov/sites/default/files/2020-09/E-1_0.pdf

[4] NARUC. Task Force on Comprehensive Electricity Planning. Available online at https://www.naruc.org/committees/task-forces-working-groups/retired-task-forces/task-force-on-comprehensive-electricity-planning/home/

[5] California Public Utilities Commission. 2021, July 2. Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future. R.21-06-017. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M390/K664/390664433.PDF

[6] New York State Department of Public Service. Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision. https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-m-0101

[7] U.S. DOE. 2023, September. Pathways to Commercial Liftoff: Virtual Power Plants. Available online at https://liftoff.energy.gov/wp-content/uploads/2023/10/LIFTOFF_DOE_VVP_10062023_v4.pdf

[8] The White House, National Climate Task Force. President Biden's Actions to Tackle the Climate Crisis. Available online at https://www.whitehouse.gov/climate/#:~:text=Reducing%20U.S.%20greenhouse%20gas%20emissions,clean%20energy%20to%20disadvantaged%20communities

[9] U.S. DOE. Distribution Grid Transformation. Available online at https://www.energy.gov/distribution-grid#:~:text=The%20U.S.%20Department%20of%20Energy,particularly%20at%20the%20distribution%20grid

- Provide the tools for practitioners to create their roadmaps and pathways for capability building in relation to and proportional to increasing DER and electrification levels.

- Lay out the best practices and industry standards that will assist in the attainment of jurisdictional goals.

The development of standardized solutions and practices will aid in developing alignment across the industry for the benefit of customers. An understanding of the grid codes and the associated practices for code implementation can provide utilities and state regulators with insight into the steps required for DER integration, device and technology manufacturers with a sense of where research and development efforts should be focused, and project developers with consistent interconnection regimes across states. That said, the distribution grid code framework and adoption pathways matrix are not intended to dictate prescriptive solutions. The framework is intended to act as a guide and a starting point for DER integration activities. Specific approaches, and the choices of the various grid code elements themselves, will be dependent on jurisdictional goals, customer objectives, and organizational capabilities, among other factors.

The Distribution Grid Code Framework and Taxonomy

Broadly, grid codes dictate the requirements for new loads and generators interconnecting to electric power systems. Adherence to a set of grid codes creates a common set of expected methods and outcomes that provide stakeholders with confidence that system elements will behave as intended. The use of grid codes facilitates the building of trust among power system participants.

DOE introduced the concept of distribution grid codes in November 2023 in its prior paper, titled "Distribution Grid Code Framework." While distribution grid codes have traditionally governed technical rules and considerations (such as engineering and interconnection standards for distributed generation), DOE has broadened the purview of distribution grid codes to include institutional and business processes. DOE's grid code framework introduces a structured methodology to identify the various considerations relevant to the integration and utilization of DERs, microgrids, and electrification. Regulators and other stakeholders can use the framework to identify the scope of the implementation issues and best practices needed to achieve the jurisdictional goals relevant to DER penetration.

The distribution grid code framework and taxonomy can be used to consider the interrelated regulatory, business, and technical aspects of distribution system functions. The aim of the taxonomy is to provide regulators and stakeholders with insight into the interrelated considerations and capabilities required to achieve DER integration and utilization goals. The framework is shown in Figure 1 and its constituent pieces are further described below:

- **Grid Code Families:** Grid code families are broad functional categories relevant to the integration and utilization of DERs and electrification in distribution systems.

- **Grid Code Family Elements:** Grid code family elements are a more detailed breakdown and summary of the functions within a code family.

- **Institutional, Business, and Technical Components:** These components are the interrelated legislative, business, and technical processes, procedures, and design criteria associated with each code family element.

- **Institutional Best Practices, Business Best Practices, and Technical Standards:** The best practices and standards associated with each component describe how a grid code family element should be implemented. These include regulatory rulemaking, leading business processes and engineering practices, and recognized technical standards.

A list of all grid code families and elements is provided in Appendix A. The code families and elements were ascertained based on surveys of industry documents, peer reviews, and conversations with industry experts.

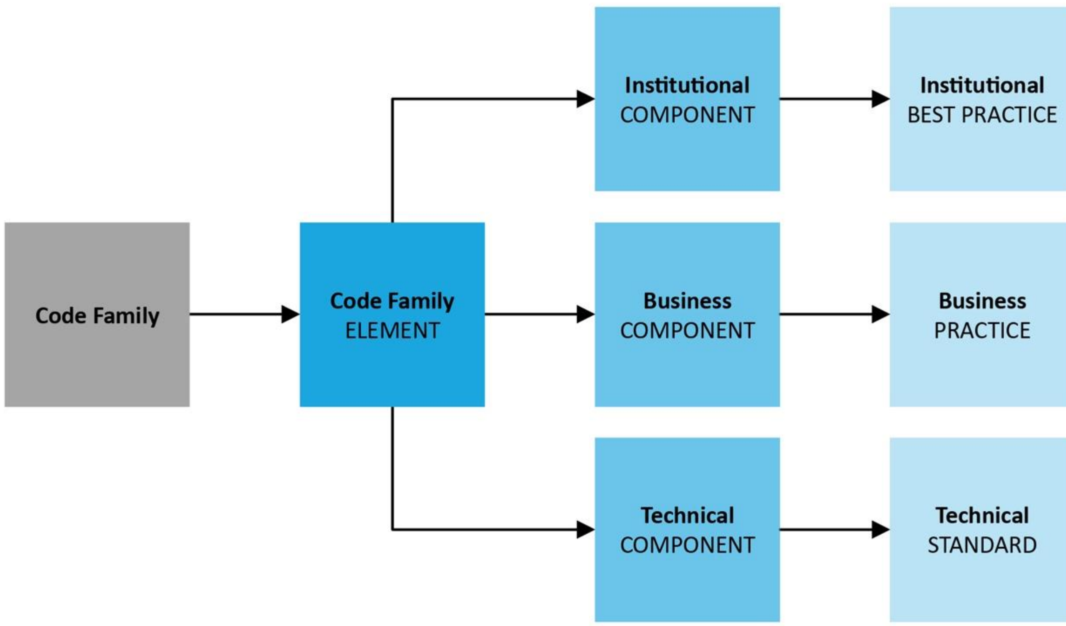

Figure 1. Distribution Grid Code Framework Taxonomy

The various layers of the grid code framework taxonomy are illustrated through the example in Figure 2 for the "Hosting Capacity Analysis (HCA)" code element, belonging to the "Grid Engineering" code family. Hosting capacity indicates the amount of DERs that can be added to the electric distribution system based on existing and future grid conditions and without circuit upgrades. In recent years, several regulatory bodies and utilities have taken steps to release HCA results in the public domain.

The various components of the HCA code element include the following:

- **Institutional Components:** Establish HCA requirements regarding the scope of the DERs to be studied, system granularity, analytic methodology, update frequency, and information sharing means for external parties.

- **Business Components:** Develop and implement organizational practices (e.g., people, processes) to conduct HCAs and enable related information sharing.

- **Technical Components:** Apply best practice HCA methodologies, as appropriate, based on the relevant work stages.

The best practices and technical standards associated with the HCA code element include the following:

- **Institutional Best Practices:** An example of a best practice is an order issued by the Minnesota Public Utilities Commission in Docket No. E-002/M-19-685 on July 31, 2020. The order provides guidance to Xcel Energy on the information to be included on HCA maps and mentions how the HCA information should fulfill multiple use cases. The order also describes how frequently these maps should be updated.[10]

- **Business Best Practices:** Examples of business best practices for HCA are mentioned in a joint National Renewable Energy Laboratory and Interstate Renewable Energy Council report.[11] The report's recommendations included the following aspects: building a well-resourced HCA team to track key metrics, developing a well-documented process for data validation to ensure that software tools reflect grid conditions, and transparent and collaborative information sharing.

- **Technical Standards:** An example of a technical best practice is a hosting capacity data validation plan created by each of California's largest investor-owned utilities. Each utility filed such a plan in response to a requirement issued by the California Public Utilities Commission. The goal of the data validation exercise was to avoid the publication of erroneous hosting capacity data. The plans document five stages of data validation: input data validation, model validation, engineering analysis, results validation, and results publication.[12]

---

[10] Before the Minnesota Public Utilities Commission: In the Matter of Xcel's 2019 Hosting Capacity Analysis Report: Order Accepting Report and Setting Further Requirements, Docket No. E-002/M-19-685. Available online at https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId=%7bC06CA673-0000-C714-93E9-DFED768388A6%7d&documentTitle=20207-165472-01

[11] Nagarajan A, Zakai Y. 2022. Data Validation for Hosting Capacity Analyses. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A40-81811. https://www.nrel.gov/docs/fy22osti/81811.pdf

[12] Teran S, Romero V. 2021, June 24. SCE Integration Capacity Analysis Data Validation Plan Assessment. Quanta Technology. Available online at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/infrastructure/distribution-planning/qtech-sce-ica-data-validation-plan-assessment-report.pdf

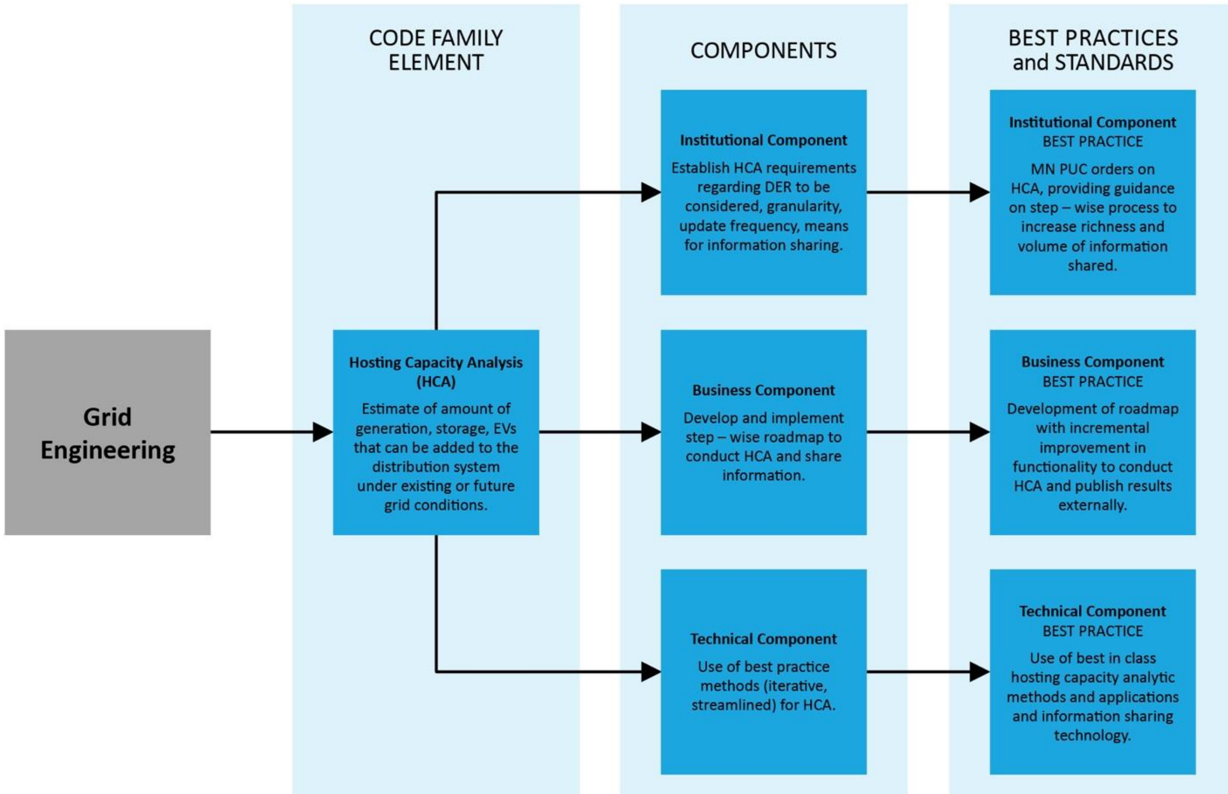

Figure 2. Distribution Grid Code Framework Example – Hosting Capacity Analysis (HCA)

Distribution Grid Code Adoption Pathways

The pace and scale of DER integration and utilization will shape the evolutionary trajectory of utility distribution systems and the timing considerations for the implementation and adoption of distribution grid codes. DER adoption is contingent on factors such as technology costs and incentives, supportive policy regimes, grid integration considerations, and customer interest, among other factors. Additionally, the ability of DERs to provide grid services in wholesale and retail markets is dependent on factors such as size thresholds for DER participation, market participation rules, the lucrativeness of DER value streams, and the scope of eligible services. These factors vary significantly from region to region.

Another factor to consider regarding the adoption of distribution grid codes includes the level of DER adoption and utilization within a utility's service territory. The level of DER penetration has implications along several technical and regulatory dimensions for utilities, including integrated distribution system planning, grid modernization technologies, and the use of DERs for grid services. Additionally, the size of the utility has a bearing on the company's organizational capabilities to address increasing requirements and responsibilities relevant to rising DER penetration. In this work, the number of customers served by the utility is used as a surrogate for a company's size.

The DER adoption and utilization trajectory can be viewed through the lens of three stages: Stage 1 corresponds to a scenario where DER penetration is low as a fraction of the utility's peak load (e.g., 5% or lower). In Stage 2, DER penetration as a fraction of utility peak load rises to between 5% and 15% and DERs are used to provide grid services. Stage 3 denotes a condition where DER penetration as a fraction of utility peak load exceeds 15% and DER grid services are expanded. The three stages of DER adoption and utilization are shown in Figure 3.

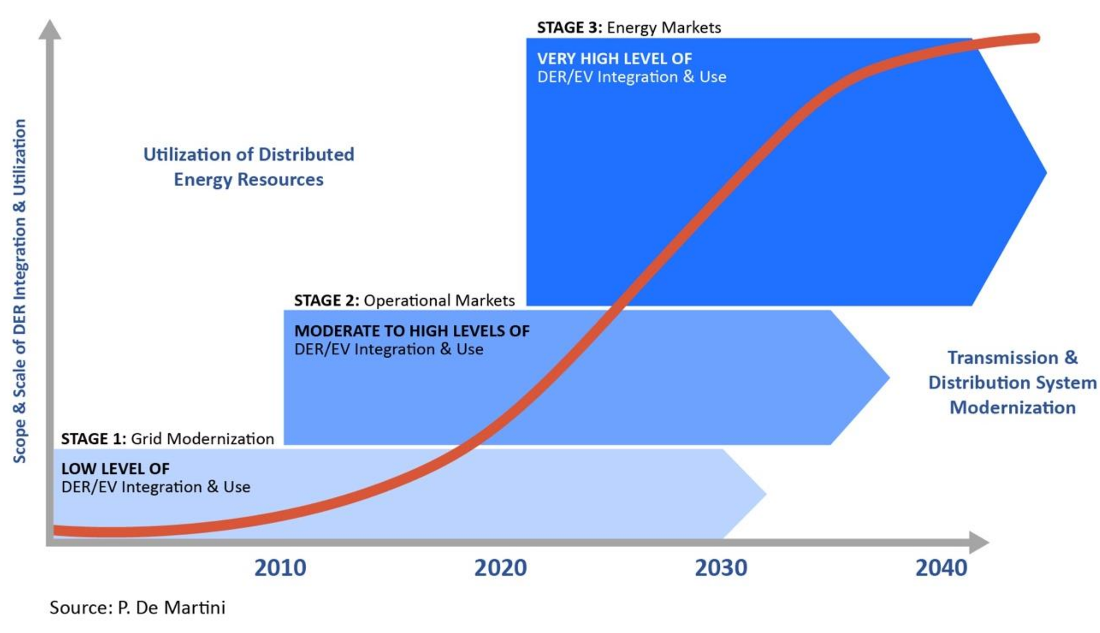

Figure 3. Stages of DER Adoption and Utilization

As mentioned previously, the number of customers served by a utility can act as a proxy to enable an understanding of a utility's ability to marshal resources to complete complex endeavors, as well as adopt organizational changes. For example, an investor-owned utility that serves more than a million customers is likely to have greater means to embark on sophisticated planning and operational analytics, major infrastructure, and grid technology projects, as compared with a smaller municipal utility or cooperative that serves a few thousand customers. The set of vendors that serve utilities of various sizes is also typically different. Within this framework, small utility systems are considered to be those with 500,000 or fewer customers, medium utilities are assumed to serve between 500,000 and 1,000,000 customers, and large utilities serve more than 1,000,000 customers.

Given these considerations, the necessity and timing of the adoption of distribution grid codes will differ among utilities. For regulators, it is important to be mindful of these considerations when prescribing DER integration and utilization goals for utilities in their service territories. To provide a guide and reference for the selection of grid codes, this paper introduces the concept of a distribution grid code adoption pathways matrix based on likely trajectories for distribution system evolution, as illustrated in Figure 4. This matrix intends to provide a guide for practitioners, illustrating the incremental grid codes that may need to be adopted for safe and reliable grid operation.

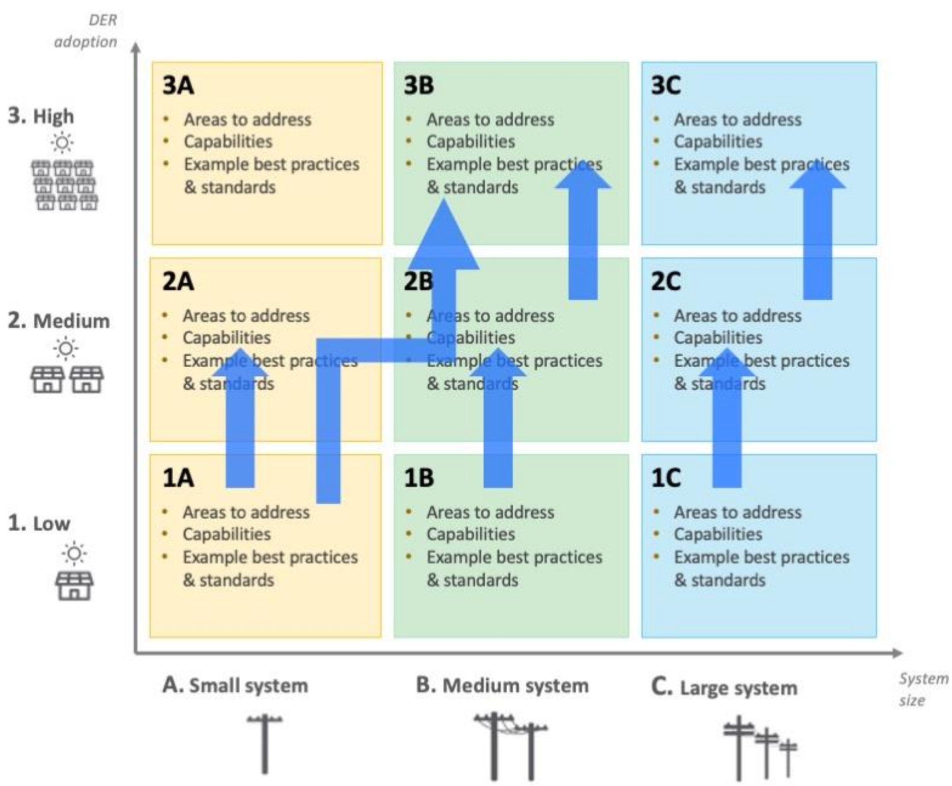

Figure 4. Distribution Grid Code Adoption Pathways Matrix

Pathways Adoption and Evaluation Process

The creation and adoption of grid code pathways is a multistep exercise that combines strategy planning techniques with consideration of local jurisdictional objectives and policy goals. These suggested steps and pathways for grid code adoption, based on current and projected scenarios of DER adoption and utility size, are illustrated in Figure 5 and described in the text below.

Figure 5. Potential Pathways for Grid Code Adoption and Evaluation

Step 1 – Identify Factors That May Necessitate Improvements in DER Integration and Utilization Capabilities

There are mainly two trigger points that may prompt the exploration and incorporation of incremental or advanced capabilities for DER integration and utilization, in turn, necessitating consideration of distribution grid codes. The first is regulatory initiative-centric—a regulator's consideration of grid codes may be prompted by a desire to facilitate DER adoption and aid customers in accessing the benefits of distributed resources. The regulator may open a new investigation or docket on these matters or direct a utility to achieve these objectives, in turn, prompting an exploration of grid codes by the utility.

The second trigger point is related to "organic" DER adoption. In this second instance, likely due to a pre-existing conducive regulatory atmosphere and policy regime and/or external factors, DER growth has reached an extent where existing utility practices to accommodate DERs are no longer sufficient. An example of this phenomenon can be observed in Hawaii, where high energy costs (due to the import of fossil fuels) contributed to the explosive growth of distributed solar photovoltaics (PV). Consequently, in such instances, the utility may need to modify its existing planning and operational practices, or adopt new ones, to facilitate the safe and reliable operation of the distribution system in a scenario with rising DER penetrations.

Step 2 – Establish Objectives for DER Integration and Utilization

For both trigger points described previously, a systematic and phased approach to grid code adoption and capability building can help. For example, consider the first instance, where jurisdictional regulatory policies and goals inform the development of grid modernization, DER integration, and distribution planning initiatives. As these policy principles and goals are necessarily specific in relation to a particular jurisdiction's situation and needs, they can serve as the foundation for a utility's detailed exploration of incremental DER integration capabilities. Elucidation of a jurisdiction's short- and long-term visions and missions enables the identification of aligned objectives. For example, the Hawaiian Electric Companies' guiding principles for grid modernization are described below:[13]

- Move toward the creation of efficient, cost-effective, and accessible grid platforms for new products, new services, and opportunities for the adoption of new distributed technologies.
- Ensure the optimized utilization of resources and electricity grid assets to minimize total system costs for the benefit of all customers.
- Enable greater customer engagement, empowerment, and options for utilizing and providing energy services.
- Maintain and enhance the safety, security, reliability, and resiliency of the electric grid at fair and reasonable costs, consistent with the state's energy policy goals.
- Facilitate comprehensive, coordinated, transparent, and integrated grid planning across distribution, transmission, and resource planning.

The guiding principles and vision, in turn, inform the creation of objectives that are unique to the jurisdiction. These objectives are often related to the improvement of existing functionality for DER integration, or the addition of new capabilities. The stated objectives should include elements relevant to the desired outcome that new capabilities should enable and should be based on a realistic expectation of timelines for implementation, based on technology maturity, resource constraints, and other factors.

Regulators can avail themselves of the institutional components of the distribution grid code framework and the best practices and standards associated with the desired grid code elements to develop their jurisdiction-specific guidelines to achieve their policies and objectives. The described institutional components and examples of best practices provide regulators with references that draw from lessons learned and issues that have been identified in other jurisdictions.

---

[13] Before the Public Utilities Commission of the State of Hawaii: Instituting a Proceeding Related to the Hawaiian Electric Companies' Grid Modernization Strategy, Decision and Order No. 35268, Docket No. 2017-0226. Available online at https://www.hawaiianelectric.com/documents/about_us/investing_in_the_future/dkt_2017_0226_2018_02_07_PUC_decision_and_order_35268.pdf

As an illustrative example, the grid modernization principles and objectives discussed by the Public Utilities Commission of Ohio (PUCO) in their PowerForward Roadmap are mapped to various grid code elements and their institutional components in Table 1 below.[14] In the example below, the list of grid code families and elements mapped to a particular PUCO objective is not exhaustive and is only intended to indicate the linkages among a regulatory objective, grid code family, grid code element, and the respective institutional component. In the future, regulatory agencies could implement such a mapping exercise using the distribution grid framework to ascertain the institutional factors aligned with their objectives. These institutional factors and associated best practices could then be adapted and incorporated into issued regulatory orders or guidance.

[14] Public Utilities Commission of Ohio. 2018. PowerForward Ohio: A Roadmap to Ohio's Electricity Future. Available online at https://puco.ohio.gov/wps/wcm/connect/gov/38550a6d-78f5-4a9d-96e4-d2693f0920de/PUCO+Roadmap.pdf?MOD=AJPERES&CONVERT_TO=url&CACHEID=ROOTWORKSPACE.Z18_M1HGGIK0N0JO00QO9DDDDM3000-38550a6d-78f5-4a9d-96e4-d2693f0920de-nLBoZhy

PUCO Objectives	Relevant Grid Code Family	Relevant Grid Code Element	Grid Code Element – Institutional Component
A Strong Grid A distribution grid that is reliable and resilient, optimized and efficient, and planned in a manner that recognizes the necessity of a changing architectural paradigm.	**Virtual Power Plants and Microgrid Services** – This code family includes aspects relevant to the provision of DER distribution grid and microgrid resilience services.	**Distribution Resilience Services** – Services provided by microgrids and DERs and compensated by utilities to mitigate the impact of high-impact, low-probability events.	**Institutional Component** – Establish distribution resilience services and compensation structures for the provision of resilience services from microgrids and DERs.
The Grid as a Platform **A modern grid that serves as a secure open-access platform—firm in concept and as uniform across our utilities as possible—that allows for varied and constantly evolving applications to seamlessly interface with the platform.**	**DER and Microgrid Integration** – This code family captures the functions and technologies required to support grid resilience and enable system safety and reliability at all levels of DER penetration.	**DER Interconnection Procedures** – These engineering analysis and study procedures govern interconnection studies for DERs applying to interconnect and operate in parallel with the utility distribution system.	**DER Interconnection Procedures** – Establish a requirement for utilities to develop and implement DER interconnection study processes and a pro forma interconnection agreement.
A Robust Marketplace A marketplace that allows for innovative products and services to arise organically and be delivered seamlessly to customers by the entities of their choosing.	**Virtual Power Plants and Microgrid Services** – This code family includes aspects relevant to the provision of DER distribution grid and microgrid resilience services.	**Retail Energy and Distribution Grid Services** – Distribution grid services include retail energy, capacity, voltage, and reactive power support on the distribution system, as well as improvements in flexibility, resilience, reliability, and increases in hosting capacity.	**Retail Energy and Distribution Grid Services** – Establish a set of defined retail energy and distribution grid services and market designs (e.g., rates, programs, procurement) for the provision of DER/microgrid services.
The Customer's Way **An enhanced experience of the customer's choosing on the application side, whether for reasons arising from financial, convenience, control, environmental, or any other chosen consideration.**	**Information Sharing and Security** – This code family is relevant to distribution system and market data dissemination and protection practices.	**Customer Data Access and Privacy** – This code element refers to tools that provide customers with the means to access their energy usage data, with data being protected by the appropriate privacy and cybersecurity controls.	**Customer Data Access and Privacy** – Establish requirements for utilities to enable customers to access their energy usage data and securely share it with third parties.

Table 1. Illustrative Mapping of PUCO Grid Modernization Objectives and Grid Code Families, Elements, and Institutional Components

In relation to the second trigger point, pertaining to “organic” DER growth, utility objectives regarding the maintenance of system safety and reliability in the presence of higher DER penetration likely come to the fore and eventually dictate the identification of capabilities to fulfill these aims. As with the principles and objectives discussed previously, these goals are necessarily jurisdiction specific. For example, a utility might forecast a steep increase in electric vehicle (EV) penetration in its service territory, with foreseeable harmful voltage and thermal impacts. Accordingly, the utility would seek to bolster its capabilities to facilitate and accommodate EV adoption by its customers, while ensuring that EV charging behavior does not adversely affect the grid.

Step 3 – Assess Current Organizational Capabilities

In an electric distribution system planning or grid modernization initiative, once the baseline of jurisdictional objectives and principles has been established, the next step should entail a “current state assessment” to identify a utility’s existing DER integration and utilization capabilities.

A capability denotes the ability to execute a particular course of action and informs the choice of a function(s) to meet a required DER integration and utilization objective. Functions define the business processes, behaviors, and technical/technological considerations necessary to enable the capabilities. The current state assessment examines the effectiveness, efficiency, sufficiency, strengths, and weaknesses of existing organizational capabilities and functions. Such an assessment is an essential first step in identifying the maturity and capacity of existing processes. The results of the current state assessment represent a benchmark. Incremental capabilities and functions that can accomplish the necessary DER integration and utilization activities should be measured against this benchmark, and must advance the level of the process and technical maturity within the utility.

Step 4 – Determine the High-Level Advanced Capabilities and Required Functionalities

The next step in the process of grid code adoption pathway identification includes the utility’s determination of the relative sophistication of capabilities and functions required to enable DER integration and utilization at scale. These incremental developments may include enhancements to existing technologies or the acquisition of new tools over time.

A key indicator of the level of advancement required in DER integration and utilization tools is the utility’s anticipated level of DER penetration. The DER penetration to peak load ratios mentioned previously that indicate various levels of DER adoption (0% to 5% represents low adoption, 5% to 15% is considered medium, and more than 15% is considered high adoption) can be used as reference points to illustrate when gradual development, or perhaps even a step change in utility capabilities, is required. Using projections of future DER adoption allows the utility to develop a sense of timing regarding the need to implement advanced functionality.

To achieve the desired functional enhancements, it also is advisable for the utility to develop a multistep, logical pathway that bridges the gap between the current state and future functionality that is required (as dictated by jurisdictional goals). For example, consider a utility that has been ordered to provide hosting capacity information to external parties as DER interconnection requests grow. At low DER penetrations, the utility could start by publishing online heat maps to illustrate the available capacity for new solar PV interconnections, eventually transitioning to publishing circuit and substation information using geographic information system tools. As DER penetration grows, the utility could expand the functionality of the maps to include other DERs, such as battery storage and EVs. As DER penetration grows even further, the utility could use hosting capacity data to identify areas of the grid that may need upgrades or reinforcements to accommodate new resource interconnections.

The development of such a logical pathway(s) can be informed by the distribution grid code framework and is further described below.

Step 5 – Identify Grid Code Families, Elements, and Components Associated with the Desired Objectives

Utilities can use the grid code framework to identify the level of business processes, engineering practices, and technical standards that align with regulatory requirements, customer needs, and DER penetration trends. In the context of the distribution grid code framework, the listing of the business, technical, and institutional components associated with a jurisdictional objective can result in more accurate identification of the applicable functions and technologies. The business and technical components and applicable best practices and standards associated with the relevant code family elements can provide insight into the pertinent capabilities and functions necessary to enable DER integration objectives.

For example, consider an electric utility that is forecasting an upward trend in customer EV adoption and wishes to put in place the appropriate programs and rate structures to facilitate this transition. The business and technical components associated with the "Transportation Electrification" grid code element can provide insight into and serve as a foundation and starting point for a detailed consideration of the new capabilities and functions that will be needed.[15] The utility could use the descriptions of the business and technical components to identify the capabilities and associated functions that would be required to achieve its transportation electrification goals.[16] Table 2 presents such a mapping and illustrates the related capabilities and functions.

---

[15] The full list of grid code families and elements can be found in DOE's "Distribution Grid Code Framework" paper. Available online at https://www.energy.gov/sites/default/files/2023-11/2023-11-15%20Distribution%20Grid%20Code%20Framework_optimized.pdf

[16] U.S. DOE. 2019, November. Modern Distribution Grid (DSPx), Volume I: Objective Driven Functionality, Version 2.0. Available online at https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume_I_v2_0.pdf

Objective	Grid Code Components	Capability	Function
Enable Transportation Electrification	**Business Component** – Develop new rates, incentives, and programs for customers with the goal of facilitating transportation electrification.	***Accommodate Technological Innovation*** – Facilitate the integration of EVs to enable net positive benefits for customers. ***Open and Interoperable*** – Enable active participation by customers in new services and markets, and accommodate all types of EVs (light-, medium-, and heavy-duty vehicles and fleets).	***Programs*** – Develop and launch utility EV programs with funding by utility customers through retail rates or by the state. ***Advanced Pricing*** – Create EV-specific rates (such as time-of-use rates) that reflect changes in factors such as time, peak load, and the controllability of supply and demand resources.
	Technical Component – Apply best practice methods, as appropriate, based on the implementation stages and the level of EV penetration.	***Situational Awareness*** – Situational awareness involves operational visibility into EV charging patterns, events, and grid conditions that may need to be addressed. ***Distribution Investment Optimization*** – Identify and source the grid infrastructure and technology assets to enable efficient investment and operational expenditures for safe and reliable accommodation of EVs.	***EV Readiness*** – Enable the advancement of transportation electrification by upgrading and enhancing grid cyber-physical infrastructure to facilitate the construction of charging infrastructure and support the adoption of EVs. ***Short- and Long-Term Demand and EV Penetration Forecasting*** – Forecasts of electricity consumption and growth for distribution circuits from electrification, and forecasts of expected EV penetration.

Table 2. Illustrative Mapping of the Grid Code Framework Components Associated with Electrification to Relevant Capabilities and Functions

Hence, for utilities grappling with considerations relevant to "organic" DER growth, the business and technical components of the grid code framework can serve as guides that enable the identification of functions for DER integration and utilization. The choice of the appropriate capabilities and functions to acquire is governed by the utility's projections of DER penetration. Nonetheless, the complexity and nature of the new tools to be implemented can depend on several factors, including organizational and structural changes, the time needed to train staff, and budget considerations.

Timing Considerations for Distribution Grid Code Adoption

The pace and timing of grid code adoption to increase utility maturity regarding DER integration and utilization activities should be tied to customer expectations, public policy directives, organic DER adoption, and the activities of third parties, such as DER aggregators, among other factors.

However, a challenge for utilities in this regard is that the evolution of customer needs, DER adoption, and timelines mentioned in policy objectives may be more rapid than the time it takes to implement distribution investments and new grid infrastructure. Additionally, utilities face challenges such as a lack of commercially available products, long lead times to pilot and test new equipment, and integration with legacy systems, among others. These factors point to the necessity of utilities adopting a flexible and adjustable approach when considering grid code adoption for DER integration and utilization activities.

As an initial activity to develop a logical pathway for grid code adoption, every jurisdiction or utility will need a keen grasp of its current state and status quo capabilities for DER integration, future trajectories such as projected DER growth, and relevant regulatory objectives and policies. As a next step, and as described previously, a utility could use the distribution grid code framework to identify the interrelated institutional, business, and technical components associated with its goal(s) for DER integration and utilization. When used with a resource such as DOE's Modern Distribution Grid Report series, the grid code framework can illustrate the capabilities and functions needed to achieve the DER integration goals. Consequently, the utility should identify a logical progression in sophistication and complexity needed to attain the desired capabilities and functions.[17]

For example, consider the illustrative example of the medium-sized utility, serving 500,000 customers, which is grappling with the rising electrification of transportation. The utility anticipates that the percentage of households owning an EV in its service territory will rise from 0.1% to 5% within the next 5 years. In the context of the grid code adoption pathways matrix, this means that the utility is transitioning from Box 1B to Box 2B; while the number of customers who the utility serves will remain roughly the same, DER penetration in the utility's territory will rise (as illustrated by growth in the number of EVs). To enable this trend and the customer adoption of EVs, the utility will not only need to implement new processes, capabilities, and functions, but also ensure that the procedures it implements are well documented, scalable, and repeatable. These processes also will need to mature, be standardized, and improve in efficiency over time as more customers adopt EVs.

A crucial factor to consider when contemplating the adoption of advanced distribution grid codes is the organizational capacity of the utility to support advancements in DER integration and utilization activities. This refers to factors that are relevant to staff availability, skills, and the required resources. Without access to these resources, DER integration activities are unlikely to be successful and attain their intended objectives. Another consideration in this regard is the vendor landscape and the ability of vendors to

[17] Modern Distribution Grid Project. Available online at https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx

support utilities while also conducting their own product and research development activities. This concern is especially pertinent because different vendors typically serve different sizes of utilities, which means that the solutions offered by a particular vendor may not necessarily be applicable and transferable for all utilities. For example, the type of vendor that serves large utilities with more than a million customers is typically different from the one that serves small municipalities and co-ops.

Grid Code Adoption Pathway Examples

Seattle City Light

Seattle has aggressive goals to reduce the city's GHG emissions from transportation and buildings and combat climate change. Seattle's Climate Action Plan aims to reduce pollutant levels in the city by 58% below 2008 levels by 2030 and achieve net zero emissions by 2050.[18] As approximately 66% of the city's emissions are driven by transportation and the remainder from buildings, there is an imperative to electrify vehicles and heating sources. These electrification goals directly affect the city's municipal utility, Seattle City Light (SCL), which must take steps to accommodate and facilitate the electrification of vehicles and heating sources. Of note, SCL has relatively low DER adoption in its service territory and most deployed DERs are those adopted as energy efficiency measures. Given current and forecasted DER penetration levels and a customer base of approximately 500,000 electric accounts, SCL may be considered to be in Box 1A of the grid code adoption pathways matrix.

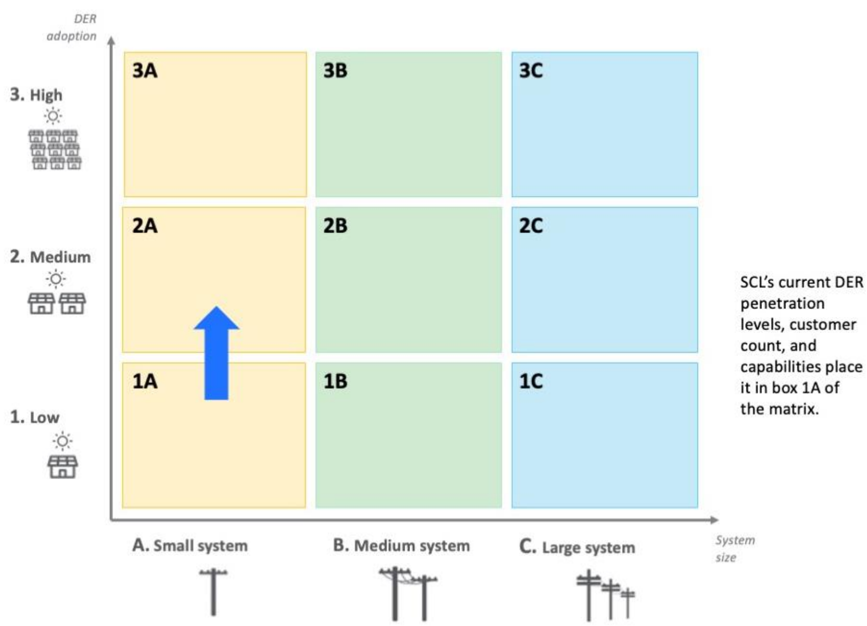

Figure 6. Illustrative Distribution Grid Code Adoption Pathway – Seattle City Light

Based on Seattle's climate and decarbonization goals, a set of distribution grid code families, elements, and components that could contribute to SCL's strategic vision are discussed in Table 3.

[18] City of Seattle. 2018, April. Seattle Climate Action. Available online at https://durkan.seattle.gov/wp-content/uploads/sites/9/2018/04/SeaClimateAction_April2018.pdf

SCL Functional Area	Applicable Code Family	Applicable Code Element	Applicable Code Component(s) Addressed by SCL Activity
DER Interconnection Procedures	DER and Microgrid Integration	DER Interconnection Procedures	***Business Component*** – Create a DER interconnection process that describes milestones from application submittal to permission to operate. Create a standardized interconnection agreement describing aspects such as the responsibilities of the parties, inspection and testing, effective date and term, cost responsibility, and so forth. ***Technical Component*** – Develop and document the technical study practices and procedures for DER interconnection.
Transportation Electrification	Grid Engineering	Transportation Electrification	***Business Component*** – Develop new rates, incentives, and programs for customers with the goal of facilitating transportation electrification. ***Technical Component*** – Apply best practice methods, as appropriate, based on the implementation stages and the level of EV penetration.
Non-Wires Alternatives (NWAs)	Grid Engineering	Locational Value Analysis	***Business Component*** – Develop a transparent solution identification workflow, including DER tariffs/programs and third-party NWAs for inclusion in the distribution system planning process. ***Technical Component*** – Apply best practice DER solution screening and evaluation methodologies to procure DER services that are aligned with grid needs.
Demand-Side Management Capabilities	Virtual Power Plants and Microgrid Services	Retail Energy and Distribution Grid Services	***Business Component*** – Develop and implement retail and distribution grid services mechanisms, including the related performance requirements to facilitate DER and microgrid services provision and settlement. ***Technical Component*** – Develop a standard retail energy and distribution grid services agreement for the provision of DER and microgrid services.
Cybersecurity	Information Sharing and Security	Cybersecurity	***Business Component*** – Develop a utility process to build cyber hygiene, awareness, and security capabilities within the company. ***Technical Component*** – Implement best practices and National Institute of Standards and Technology cybersecurity standards and other applicable industry standards (e.g., the North American Electric Reliability Corporation Critical Infrastructure Protection requirements).

SCL Functional Area	Applicable Code Family	Applicable Code Element	Applicable Code Component(s) Addressed by SCL Activity
Development of Operational Capabilities	DER and Microgrid Operations	Utility Investments in Operational Technology (Advanced Distribution Management System/ Distributed Energy Resources Management Systems/Supervisory Control and Data Acquisition)	***Business Component*** – Develop a process to identify the justification and implementation plans for information and operational technologies. ***Technical Component*** – Develop a robust technology identification process (including the definition of use cases for technology, issuance of requests for information, and a vendor selection process) through final implementation of the technology solution.

Table 3. SCL Functional Areas and Applicable Grid Code Families and Elements

SCL is taking action to facilitate electrification and grid modernization and integrate technologies that maintain system safety and reliability.[19] SCL's activities are summarized in the functional areas in Table 4 and are mapped to the relevant grid code families and elements from Table 3. Brief descriptions are provided regarding the new tools, capabilities, and functionalities that the company is implementing.

Utilities in a similar position as SCL would benefit from aligning their planned activities and initiatives with the best practices and standards associated with the distribution grid codes that are most appropriate for their DER integration and utilization goals. For example, regarding the technical considerations for DER interconnection, utilities could consider adopting all aspects of Institute of Electrical and Electronics Engineers (IEEE) 1547-2018, including a phased approach for incorporating autonomous/unattended inverter settings, and consequently implementing more sophisticated monitoring and control capabilities through the inverter communications interface. Utilities could adopt these capabilities in a stepwise and logical manner as DER penetration rises over time in its service territory. As an additional example, regarding non-wires alternative (NWA) deployment, utilities could develop a process built around the three key criteria that aid in NWA procurement and deployment: project type, timeline, and cost. These criteria can be further refined as companies gain experience with assessing NWA opportunities.

[19] Seattle City Light. 2021, April. 2021 Grid Modernization Plan and Roadmap. Available online at https://www.seattle.gov/documents/Departments/CityLight/GridModRoadmap.pdf

Functional Area	Activities and Timeline
DER Interconnection Procedures	**2021–2026:** SCL is updating its DER interconnection standards and process to accommodate resources other than solar PV. SCL also will incorporate IEEE 1547-2018 into its interconnection procedures and implement monitoring and control requirements for DERs. SCL is seeking to study and determine circuit hosting capacity and an online customer DER application portal. **2026–2030:** SCL will ensure that data from the DER interconnection process feed into other planning processes so that DER impacts on the load can be captured. SCL also will seek to implement an automated DER interconnection process.
Transportation Electrification	**2021–2026:** Working with the Pacific Northwest National Laboratory, SCL will explore the possibility of implementing networked microgrids with multiple sources of generation at the Port of Seattle, thus facilitating the electrification of marine vessels. SCL also will implement a study of managed EV charging schemes, including a pilot project for medium- and heavy-duty fleets, and analyze the impact of shaped charging through retail rates. **2026–2030:** SCL will continue to explore new ownership and maintenance models for DERs at the port. SCL also will develop a vehicle-to-grid (V2G) pilot for medium- and heavy-duty fleets, based on whose success a V2G program may be implemented. SCL also will develop rates for multiple EV managed charging options.
Non-Wires Alternatives (NWAs)	**2021–2026:** SCL will conduct a best practice analysis of other utilities and frameworks for NWA screening and evaluation. SCL also will develop NWA screening criteria, processes, and tools and incorporate these into the distribution planning process. SCL will put programs in place to accurately compensate customers who are part of NWA projects. **2026–2030:** SCL will update NWA screening and evaluation criteria to reflect industry trends and lessons learned from past NWA projects. SCL also will continue to evaluate available tools to automate processes where possible.
Demand-Side Management Capabilities	**2021–2026:** While SCL currently has a low penetration of demand-side resources, the company is considering demand response (DR) programs for load shifting and peak shaving needs. These programs will likely include grid-interactive water heaters and smart thermostats for residential and/or small commercial customers. SCL also will develop a standardized benefit-cost assessment methodology for DR resources. **2026–2030:** SCL will explore the implementation of operational systems for wide-scale orchestration of DR resources and will actively seek grid benefits from these resources. SCL also will aim to incorporate DR as a standard tool for planning and operational purposes in the organization.

Functional Area	Activities and Timeline
Cybersecurity	**2021–2026:** SCL will ensure that standardized cybersecurity analysis and methods are applied in projects with the generation of security reports. SCL also will ensure that communication between the customer and utility equipment integrates cyber protections, and that event files and reports are generated as needed. SCL will build a new cybersecurity system for its distribution automation (DA) and fault location, isolation, and service restoration (FLISR) scheme and integrate it with the utility's centralized operational technology system. **2026–2030:** SCL will implement a standardized cybersecurity policy for grid assets. DERs in the field will have standardized communication mechanisms and will be monitored for cyber issues. SCL also will integrate a new DA remote switching system with the broader DA cybersecurity monitoring system.
Development of Operational Capabilities	**2021–2026:** SCL will implement FLISR schemes at additional feeders on multiple substations and integrate these with the outage management system. SCL also is piloting automated distribution switches and integrating these with the supervisory control and data acquisition/energy management system components and the PI historian software. SCL is exploring a network design and pilot for a new field communications system and devices that can eventually replace its radio mesh network. SCL also is deploying line sensors on its distribution system, which can remotely communicate with the utility's control room when a fault is detected. **2026–2030:** SCL will expand the implementation of the FLISR scheme to 20% of all overhead feeders and automated switches to 50% of overhead feeders. SCL is also aiming to expand the new communications system to up to 50% of the company's service area. SCL will integrate line sensor monitoring data into its distribution management system, and potentially a future advanced distribution management system.

Table 4. SCL Functional Areas and Anticipated Activities

Eversource Energy Massachusetts

In January 2024, Eversource Energy released a detailed Electric Sector Modernization Plan for its Massachusetts service territory.[20] The plan describes initiatives that the company is undertaking to support decarbonization goals, spur electrification, and improve system resilience to mitigate the impacts of climate change. Additionally, the plan also describes the steps that the company will take to facilitate rising DER penetration. In 2023, DER penetration as a fraction of peak load across Eversource's four subregions stood at 23%.[21] While the impacts from large customer loads and transportation and heating electrification are projected to result in an increase in the company's peak demand over the next 10 years (until 2033), DER penetration also is expected to rise during that period. Hence, by 2033, the fraction of DER penetration to peak load is expected to be 36%. With a customer count of approximately 1.5 million in Massachusetts and given its relatively high levels of existing and projected DER penetration trajectories, Eversource can be considered to currently be in Box 2C of the grid code adoption pathways matrix.

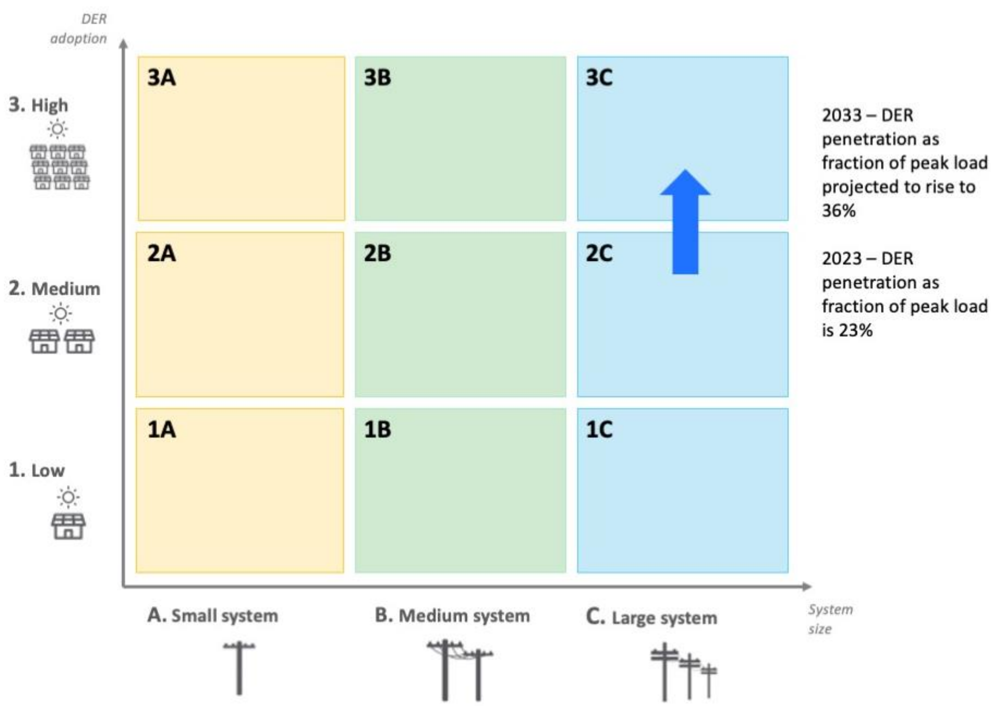

Figure 6. Illustrative Grid Code Adoption Pathway – Eversource Energy Massachusetts

Eversource has identified the need to advance its capabilities to fully address the requirements associated with Stage 2 of DER penetration, as well as evolve into Stage 3. The related functional areas are mapped to a relevant grid code family, element, and component in Table 5. Activities to facilitate greater penetration of DERs are summarized in the functional areas in Table 5.

[20] Eversource Energy. 2024, January. Electric Sector Modernization Plan. Available online at https://www.eversource.com/content/docs/default-source/default-document-library/eversource-esmp%20.pdf

[21] The DERs considered included solar PV, battery energy storage, combined heat and power, combustion turbines, distributed wind, and fuel cells.

Eversource Functional Area	Applicable Code Family	Applicable Code Element	Applicable Code Component(s) Addressed by Eversource Activity
Advanced Distribution Management System (ADMS)	DER and Microgrid Operations	Utility Investments in Operational Technology	***Technical Component*** – Develop a robust technology identification process (including the definition of use cases for technology, issuance of requests for information, and a vendor selection process) through the final implementation of a technology solution.
Interconnection Automation	DER and Microgrid Integration	DER Interconnection Procedures	***Business Component*** – Create a DER interconnection process that describes milestones from application submittal to permission to operate. Create a standardized interconnection agreement describing aspects such as the responsibilities of parties, inspection and testing, effective date and term, cost responsibility, and so forth. ***Technical Component*** – Develop and document the technical study practices and procedures for DER interconnection.
Distributed Energy Resources Management Systems (DERMS)	DER and Microgrid Operations	Distributed Resource Management – Utility	***Business Component*** – Develop utility processes to monitor and control utility and third-party DERs and aggregations through bidirectional communications. ***Technical Component*** – Ensure utility dispatch of DERs on a fair and equitable basis to meet grid needs without providing preferential treatment to DERs owned by the utility.
Transportation Electrification	Grid Engineering	Transportation Electrification	***Business Component*** – Develop new rates, incentives, and programs for customers with the goal of facilitating transportation electrification. ***Technical Component*** – Apply best practice methods, as appropriate, based on the implementation stages and the level of EV penetration.
Community Solar	DER and Microgrid Integration	Community-Based Renewable Energy (CBRE)	***Business Component*** – Develop and implement CBRE programs. Provide customers and third parties with information on financial incentives and allowances, eligibility criteria, application process overview, and so forth.

Table 5. Eversource Functional Areas and Applicable Grid Code Families and Elements

The specific actions that Eversource is pursuing relevant to the grid code elements and components in Table 5 are shown in Table 6.

As noted previously, utilities could benefit from aligning their planned activities and initiatives with the best practices and standards associated with the distribution grid codes that are most appropriate for their DER integration and utilization goals. For example, in the realm of transportation electrification, different strategies exist to facilitate EV adoption for different types of customers (e.g., residential single and multifamily, fleets, mass transit). Utilities such as Eversource could adopt and implement incentives targeted at specific customer groups, thus improving customer satisfaction. For example, for residential accounts, utilities could offer increased incentives and rebates for low-income customers and assistance with enrolling in a managed charging program. For fleets, a utility could offer fleet advisory services, aiding customers in finding equivalent replacements for their internal combustion vehicles.

Functional Area	Activities and Timeline
Advanced Distribution Management System (ADMS)	**2023–2025:** Eversource is implementing an ADMS to provide system operators with the as-operated electrical model for the distribution system. The ADMS will be fed data from the company's geographic information system, other asset databases, outage management system, and substation and field devices. The ADMS will be used to run real-time load flow calculations to support grid operations, including the resolution of system issues with DERs.
Interconnection Automation	**2023–2025:** Eversource is implementing a software solution to increase the efficiency and effectiveness of the DER interconnection application process. This solution will integrate with existing tools, such as PowerClerk, Synergi, and Power Systems Computer-Aided Design. The company also is incorporating hosting capacity data into the interconnection platform, improving the ability of developers to evaluate various interconnection options.
Distributed Energy Resources Management Systems (DERMS)	**2023–2025:** The first phase of Eversource's DERMS deployment is aimed at enabling the monitoring and control of DERs and connecting a database of DERs and an interface with the ADMS for one region of its service territory. Eversource will build a capability to use DERMS to set DER setpoints (MW/MVAR, power factor settings, volt-watt, and frequency-watt). The interface with the ADMS will allow operators to send commands to DERs. **2025–2029:** In Phase 2 of the DERMS deployment, Eversource will deploy the tool in all regions of its service territory, along with ADMS integrations. This phase also includes the implementation of multivariable dispatch optimization to support market-based dispatch. The deployment also will include integration and interoperability with third-party aggregator DERMS to control a broad swath of DERs. This initiative will involve the incorporation of communications protocols such as IEEE 2030.5 and Open Automated Demand Response.
Transportation Electrification	**2023–2033:** Eversource is implementing several programs to reduce the cost of EV charging, expand access to chargers, and support rising EV adoption in its service territory. These programs include providing customer rebates for installing residential EV chargers, rebates for utility and customer EV infrastructure at multi-unit dwelling sites and public and workplace charging sites, support for light-duty fleet electrification, new rates and pricing, and the introduction of managed charging programs.
Community Solar	**2023–2033:** Eversource currently operates the Solar Massachusetts Renewable Target (SMART) Program, which has resulted in more than 750 megawatts of installed PV capacity. To supplement this program and expand access to solar projects, the utility has proposed three new programs: the Community Solar Access Program, the Community Solar Resilience Program, and the Affordable Solar Access Program. These programs are aimed at reducing barriers for low-income and multifamily building dwellers to access solar programs.

Table 6. Eversource Functional Areas and Anticipated Activities

The examples above provide illustrations of the steps that regulators and utilities can take to enable rising DER adoption and utilization. The goal of these examples is to provide the reader with a sense of the types of activities that can be undertaken, the timeline and scale of the activities, and the incremental functionality that is enabled to facilitate DER integration and utilization. The activities that a particular regulator and utility adopts will necessarily be jurisdiction specific and depend on its local context, objectives, policies, and customer needs. Nonetheless, these examples can provide other entities with a starting point and reference to build their own DER integration pathways.

Conclusion

To achieve the goals of integrating DERs on a massive scale, facilitating the adoption of flexible resources, and accruing benefits from them, resource deployment efforts and initiatives need to be standardized to the extent practicable. These approaches should account for the fact that DER integration pathways will differ by jurisdiction and depend on unique local circumstances and policies. This paper provides an overview of and illustrates the linkages between two distinct concepts—the distribution grid code framework taxonomy and the grid code adoption pathways—to aid practitioners in charting a course for DER integration and utilization. The aim of the taxonomy is to provide regulators and stakeholders with insight into the interrelated considerations and capabilities required to achieve DER integration and utilization goals. As described previously in the section on the adoption pathways, for a utility of a particular size (in terms of the number of customers) and a projected DER adoption and grid modernization trajectory, the distribution grid code framework can be used in conjunction with resources such as DOE's Modern Distribution Grid Report to identify specific capabilities and functions that facilitate DER integration goals.[22]

These concepts aim to highlight the interrelated institutional, business, and technical components of DER services, present a mechanism to construct pathways to evaluate and choose distribution grid codes, and illustrate the sophistication of processes for utilities of various sizes and with varying levels of DER penetration. When implemented together, these frameworks and concepts will allow practitioners to begin to develop a logical, stepwise adoption approach for the implementation and adoption of distribution grid codes, in turn, facilitating DER integration and utilization.

[22] Modern Distribution Grid Report. Available online at https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx

Appendix A – Distribution Grid Code Families and Elements

The table below contains the distribution grid code families and elements described in the "Distribution Grid Code Framework" paper.

Grid Code Family	Grid Code Element	Definition
Grid Engineering	**Hosting Capacity Analysis**	Planning studies that estimate the amount of generation, storage, and EVs that can be added to the electric distribution system at a given time and location under existing or future grid conditions without system upgrades.
	Short- and Long-Term DER Adoption Forecasting	Planning analysis to estimate the growth of distributed resource types, such a solar PV, and other distributed generation, storage, and EVs over various time horizons across a distribution system. This includes forecasting the associated net load.
	Locational Value Analysis	Studies to determine the potential value (e.g., generation, capacity, frequency response, ramping) that DERs can provide at a specific location on the distribution system.
	Transportation Electrification	Analyses to determine the impacts of increased electrification of transportation, such as the addition of light-, medium-, and heavy-duty EVs. The outputs of these analyses typically include quantification of the incremental energy required to serve new loads and an assessment of change in system peak loads.

Grid Code Family	Grid Code Element	Definition
DER and Microgrid Integration	**Inverter-Based Resources (IBRs)**	Assets that require a power electronic device (an inverter) to convert their direct current electric output to an alternating current output. Common examples of IBRs on the distribution system include solar PV and battery energy storage.
	DER Monitoring and Control	DER monitoring and control capabilities include the observation of distribution grid and DER parameters (including factors that affect DER performance, such as temperature and irradiation) and the ability to control and/or adjust DER output.
	DER Interconnection Procedures	Engineering analysis and study procedures that govern interconnection studies for DERs applying to interconnect and operate in parallel with the utility distribution system.
	Community-Based Renewable Energy	Refers to installations such as community solar gardens and solar farms that operate under a virtual net metering or virtual power purchase agreement regime and community microgrids operating under a microgrid tariff.
	Microgrids	Microgrids consist of groups of controllable DERs that are designed to serve loads within a discrete geographical boundary. Microgrids can connect and disconnect (island) from the broader electric distribution system.

Grid Code Family	Grid Code Element	Definition
Virtual Power Plants and Microgrid Services	**Retail Energy and Distribution Grid Services**	Distribution grid services include retail energy, capacity, voltage, and reactive power support on the distribution system, as well as improvements in flexibility, resilience, reliability, and increases in hosting capacity.
	Distribution Resilience Services	Distribution resilience services are provided by microgrids and DERs that are compensated by electric utilities. These services are intended to mitigate the impact of high-impact, low-probability events that adversely affect the electric grid.
	DER Aggregation	A collection of DERs located behind or in front of the customer meter that is orchestrated by an entity (known as a DER aggregator) for participation in retail (distribution level) and wholesale (independent system operators/regional transmission organizations) markets.
	DER Aggregator Wholesale Market Services	Utility tariffs and agreements that define the rules and regulations for distribution-connected DERs that wish to participate in wholesale electricity markets (standalone or through an aggregation). This code element also includes an administrative workflow and process that guides DER aggregators in the submission of information for an electric utility 60-day technical study of DER aggregation impacts (as mandated under Federal Energy Regulatory Commission Order 2222).

Grid Code Family	Grid Code Element	Definition
DER and Microgrid Operations	**Distributed Resource Management – Utility**	The management and dispatch of DERs by utilities, based on the use of optimization tools, control systems and architectures, and DER analytics.
	Distributed Resource Management – Aggregator	The management and dispatch of DERs by DER aggregators, based on optimization tools, control systems and architectures, and DER analytics.
	Operating Agreements	Documents that govern project development, testing, and commercial operations. Agreements will include operational coordination requirements applicable to the unique characteristics of the project and general requirements to comply with utility operations (e.g., microgrid operating agreements).
	Common Information Model (CIM)	The CIM contains a set of standards for representing the major power system components within a utility's operational environment. The goal of the CIM is to assist in the exchange of power system network data among companies, the exchange of data among applications within a company, and the exchange of market data among market participants.
	Utility Investments in Operational Technology	Operational technologies use grid devices to capture and analyze information on grid parameters and behavior to help improve visibility and situational awareness, which, in turn, helps inform operational coordination and grid planning practices.
	Registration of DERs and DER Aggregations for Market Services	Registration of DERs and aggregations by DER aggregators and customers for participation in retail and wholesale markets.
	Market Participation Rules Validation for DER Aggregations	The ability of independent system operators/regional transmission organizations and utilities to validate the proposed market participation strategies of DERs and DER aggregations against established retail and wholesale market rules.
	Net Load Baselining and Performance Analytics for DERs and DER Aggregations	Baselines establish a customer's net load in the absence of a DER. Hence, accurate net load baselining helps assess the performance of a customer's DER (injection or load reduction) in response to dispatch instructions. Verifying DER performance helps generate accurate settlement and audit data for DERs and DER aggregator services.

Grid Code Family	Grid Code Element	Definition
Information Sharing and Security	**Customer Data Access and Privacy**	This code element refers to tools that provide customers with the means to access their energy usage data, with the data being protected by the appropriate privacy and cybersecurity controls.
	Distribution System Data	This code element refers to external-facing data portals that provide utility information, such as electric reliability reports, hosting capacity maps, historical and forecasted load data, and queued and installed DERs, among other items.
	Information Sharing – Aggregators	This code element refers to the sharing of customer data (including historical energy usage data) with aggregators.
	Cybersecurity	In the context of information and data sharing, cybersecurity refers to periodic cyber risk assessments; adherence to cyber requirements; monitoring, reporting, and management of incidents; and ensuring the privacy of customer data.
Governance and Oversight	**Distribution Open Access**	A distribution tariff/provision that requires distribution utilities to provide third parties (e.g., DER developers and aggregators, customers) with non-discriminating services and open access to distribution grid, comparable to the access available to the distribution utilities themselves.
	DER Aggregator Oversight	Regulatory oversight of DER aggregator operations by state-level regulatory authorities.
	DER and Microgrid Value Determination and Cost Allocation	Evaluation of the benefits of DERs and/or microgrids via the use of a cost-benefit framework and the determination of appropriate cost allocation and recovery mechanisms to finance the construction and operation of the DERs or microgrids.
	Governance and Oversight of Wholesale Market Participating DERs	The enactment of rules and policies by state-level regulators and commission members to govern and guide the behavior of DERs and DER aggregators participating in wholesale markets.

Table 7. Distribution Grid Code Framework – List of Code Families and Element