DISTRIBUTION SYSTEM PLANNING

Proactively Planning for More Distributed Assets at the Grid Edge

A 21st Century Electricity System Issue Brief

By Advanced Energy Economy

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ADVANCED ENERGY ECONOMY

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ABOUT ADVANCED ENERGY ECONOMY

Advanced Energy Economy (AEE) is a national association of businesses and business leaders who are making the global energy system more secure, clean and affordable. Advanced energy encompasses a broad range of products and services that constitute the best available technologies for meeting energy needs today and tomorrow. AEE's mission is to transform public policy to enable rapid growth of advanced energy businesses. AEE and its State Partner organizations are active in 26 states across the country, representing roughly 1,000 companies and organizations in the advanced energy industry. Visit www.aee.net for more information.

ABOUT THIS ISSUE BRIEF

The U.S. utility sector has entered a period of foundational change not seen since the restructuring of the late 1990s. Change is being driven by new technologies, evolving customer needs and desires, environmental imperatives, and an increased focus on grid resiliency. With these developments come challenges, but also new opportunities to create an energy system that meets the changing expectations of consumers and society for the coming decades. We call this the *21st Century Electricity System:* a high-performing, customer-focused electricity system that is efficient, flexible, resilient, reliable, affordable, safe, secure, and clean. A successful transition to a 21st Century Electricity System requires careful consideration of a range of interrelated issues that will ultimately redefine the regulatory framework and utility business model while creating new opportunities for third-party providers and customers to contribute to the cost-effective management of the electricity system by utilities.

To support this transition, Advanced Energy Economy (AEE) has prepared several issue briefs that are intended to be a resource for regulators,[1] policymakers, and other interested parties as they tackle issues arising in the rapidly evolving electric power regulatory and business landscape.[2] This issue brief on **Distribution System Planning** lays out the objectives of distribution system planning and the drivers behind the changes being implemented to those processes. It then details the key elements of a planning process that can help integrate a higher percentage of distributed energy resources onto the grid, and makes recommendations on how to begin this transition.[3]

SUMMARY

The distribution grid is the backbone of a reliable electric system and an effectively planned distribution grid is critical for providing essential electric service to customers. The distribution grid enables interconnected distributed energy resources (DER) to export electricity and provide grid services, provides electric service when distributed generation (DG) systems are not generating, and provides critical grid stability in terms of maintaining voltage and frequency.

The U.S. electricity grid has a long history of growth and evolution as new sources and uses of electricity arise and change – from the rise of air conditioning and giant nuclear generating units to the steady growth of renewables over the past 20 years. Today, evolving customer needs and interests are leading to higher DER penetration, such as rooftop solar, combined heat and power systems, energy efficiency, and smart technologies for controlling loads like residential air conditioning. Utilities have been successfully accommodating these technologies into the existing system, and where there is sufficient hosting capacity – the system's ability to reliably accommodate DER injections in each area – the grid allows DG to maximize production without compromising the utility's obligation to provide safe, affordable, reliable service.

Enhancements to the distribution system, particularly the deployment of digital technologies, are providing grid operators with more visibility into, and control of, the system. These investments are enabling utilities to move beyond interconnection and accommodation to true integration of DER technologies and applications – whether installed by customers or by utilities. An integrated, intelligent grid is critical to balancing the electricity system for overall reliability and for appropriately establishing the value provided by DERs. This evolution to an integrated grid will occur over time with the pace of change depending in part on the degree of adoption of DER in various regions, as well as the characteristics of particular regions (e.g., urban vs. suburban vs. rural).

As DER continues to grow, utilities and the DER industry are seeking ways to maximize the benefits of DER to the system, while maintaining reliability and reasonable costs for customers. In many states, utilities and DER providers are coming together to consider how DER can be more fully integrated into the system, allowing utilities to take advantage of the benefits DER can provide and optimizing distribution system planning and investments to account for and include DER.

Among the various objectives of distribution system planning, utilities and DER providers are focusing on enhancing the process to examine distribution system capabilities, needs, and operational constraints. This provides a more robust view of anticipated DER growth, identifies opportunities for DER to offset or defer needed infrastructure investment, and establishes criteria that could allow DER to contribute more fully to maintaining system reliability and grow beyond current limits. This enhanced approach should also lead utilities and regulators to identify investments that provide the functionality and flexibility needed to more thoroughly integrate DER into the grid. A practical framework that we lay out in this issue brief follows four key steps:

1. **Distribution System Capabilities, Needs, and Constraints.** This includes utilities identifying and communicating the hosting capacity on different parts on the system, identifying where adding certain types of DER would be most beneficial to the system, and increasing access to certain types of non-sensitive system information, where appropriate, to enable non-utility stakeholders, including customers and third-party DER providers, to support grid needs.

2. **Load Growth Forecasts, DER Forecasts and Scenario Analysis.** Forecasting is evolving to include more granular projections of DER potential and likely customer adoption and should include robust scenario analysis and probabilistic planning of DER penetration to ensure a thorough understanding of future risks and opportunities.

3. **Integration of DERs.** To more fully integrate DERs, policymakers and utilities should identify opportunities to standardize and streamline interconnection processes, develop and implement interoperability standards, and make grid modernization investments to maintain and enhance the reliability and flexibility of the grid.

4. **Developing a Framework to Properly Value and Source Services from DERs.** To evaluate DERs on a level playing field with traditional resources and infrastructure investments, a regulatory structure should be developed to properly value and source services from DERs.

Developing and implementing these new processes will require careful planning on the part of policymakers and utilities, including taking into account interactions between the distribution system and the bulk power system. Enhanced visibility and control at the distribution level can facilitate the integration of large-scale renewable generation and also enable aggregated DER to provide services to the bulk power system, provided there is appropriate planning and coordination when DERs are providing services at both the distribution level and bulk system level.

Enhancements to distribution system planning will be implemented in an iterative manner and should include a robust and open stakeholder engagement process. It should also consider how to integrate and coordinate these processes with other planning activities to ensure they complement each other and make use of consistent assumptions (e.g., load growth, fuel prices, DER deployment). Finally, the approach to implementing new planning processes should consider each state and utility's unique circumstances, as well as recognize that the potential value to the grid of any particular DER deployment is dependent on location and performance, among other factors. Successful implementation of all of these elements will help to seamlessly integrate more distributed assets at the grid edge while ensuring that utilities are investing in a modern distribution system that will continue to provide safe, reliable and resilient delivery of electricity to customers.

Distributed Energy Resources

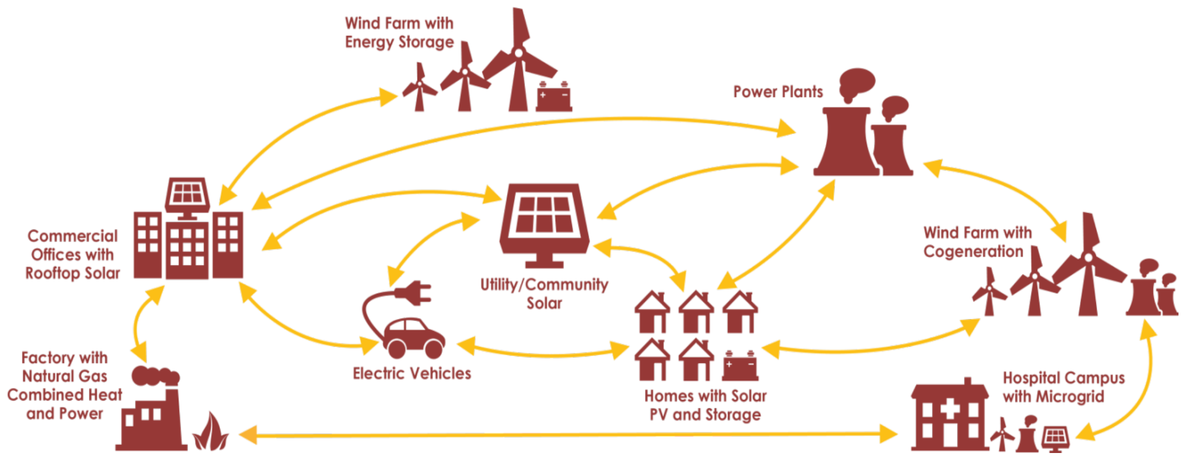
AEE defines DER broadly to include distributed generation of all types (e.g., combined heat and power, solar photovoltaics, small wind, fuel cells), energy efficiency, demand response, energy storage, electric vehicles and the associated electric vehicle supply equipment, and microgrids. As such, it includes options for generating electricity, but also for managing how much and when electricity is used.

HISTORICAL OBJECTIVES AND DRIVERS OF CHANGE

U.S. utilities currently invest over $20 billion per year replacing and modernizing their distribution infrastructure.[4] Traditionally, distribution system planning has been centered on assessing current and planned infrastructure capacity, equipment conditions, and comparing that to expected loads. Load forecasts, based largely on historical data and information on known project developments (new customers and loads), were used to identify where investments were needed to ensure adequate distribution system capacity and reliability, including both short-term and long-term capital investments and operational changes. To the extent DERs had an impact on this process, they were largely considered as modifications to the load forecast, particularly when DER penetration levels were low. This situation is beginning to change.

Rapid improvements in advanced energy technologies (including various "smart grid" technologies), increased customer adoption of DER, and changing public policy goals are now driving changes in our electric grid and have led to a shift in the types of investments needed to maintain and reliably operate the distribution grid, while ensuring that the grid is also able to meet future needs. The growth of DERs and their ability to be integrated into an increasingly intelligent grid is changing how customers meet their energy needs, use the grid and interact with their utility and with third-party providers of DER products and services. The grid is accommodating more dynamic two-way power flows between customers and the utility. Electric distribution systems were not historically designed for this type of two-way flow operation. Electricity demand that was historically seen as relatively inelastic is also becoming more responsive and dynamic. In this new 21st century electricity system, utilities will not simply interconnect and accommodate DER, but will rely on DERs, demand-management programs, and smart grid technologies and devices to operate, manage and maintain an increasingly complex distribution grid. This emerging paradigm presents both challenges and opportunities and will require changes in how utilities conduct distribution system planning. Figure 1 shows how the electricity system is becoming more dynamic and complex and is increasingly composed of numerous two-way power flows.

Figure 1: The increasingly interconnected grid



Source: Navigant Consulting.

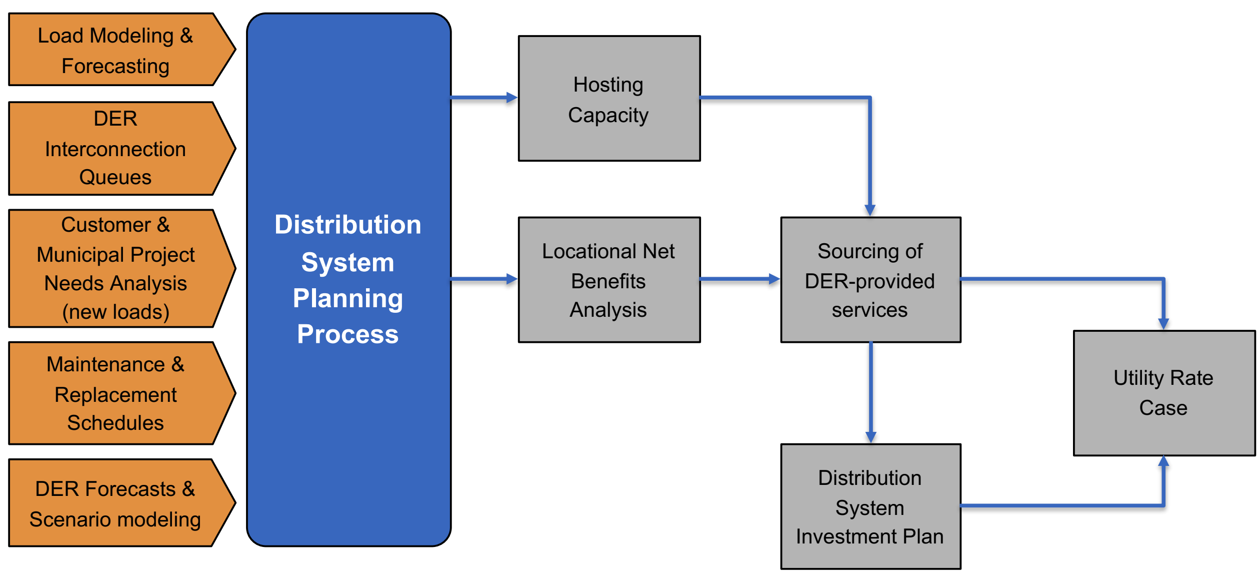
Maintaining grid safety and reliability at a reasonable cost as the grid evolves is the primary objective of distribution system planning. To achieve this, utilities will need to make investments that are consistent with emerging needs. For example, if a utility makes investments in traditional capacity expansion but over time DER growth drives down peak demand, these traditional assets may go underutilized, even as additional investments may be required to integrate this DER. Thus, utilities should consider adjusting their traditional distribution planning processes to reflect expectations for a more dynamic system in the future. This includes consideration of non-traditional investments – such as the use of utility-, customer- or third-party-owned DER – on an equal footing with traditional infrastructure investments. Ongoing grid modernization efforts will also help to unlock additional value and operational benefits from DER.

For example, even though their market penetration is low in most parts of the country today, utilities should be taking into consideration load growth from electric vehicles (EVs), and evaluating how EVs could evolve into energy storage resources. Similarly, utilities could consider scenarios whereby solar photovoltaic (PV) systems equipped with smart inverters, particularly those with reactive power injection and absorption capabilities, can be integrated more effectively. Strategically-placed energy storage could also provide balancing services and congestion relief.

A NEW FRAMEWORK FOR DISTRIBUTION SYSTEM PLANNING

Distribution system planning is a complex and integrated process that requires utility engineering, operations experience and knowledge of system connectivity and operational inter-dependencies in order to maintain reliability. There is no one-size-fits-all approach to distribution system planning. States have different levels of DER adoption and may choose to adjust their planning processes accordingly to match their circumstances. Nevertheless, modern distribution system planning processes should all contain some common elements, even as each state and utility charts its own course towards its energy future. Figure 2 shows how various components of distribution planning come together and the outputs of that effort.

Figure 2: The modern distribution system planning process



Although by no means the only objective of distribution system planning, one key outcome is to encourage DER to be sited in areas where it can be most beneficial to the grid. By making hosting capacity and non-wires solicitation information available to stakeholders, and building appropriate transparency into the planning process, utilities can help DER customers and providers to catalyze innovation and support private capital investment that complements utility investment. In turn, owners/operators of non-utility DER that provide grid services should provide appropriate information that allows the utility to optimize their value for the benefit of all customers.

Load Growth Forecasts, DER Forecasts and Scenario Analysis

Load forecasting is complex process that underpins a utility's investment plans. This bottom-up approach is critical both to identifying local system needs and, ultimately, to inform transmission and generation planning. Traditionally, distribution planning has focused on maintaining existing infrastructure and meeting evolving customer needs through infrastructure investment and system reconfiguration. While this is not expected to change, the growth in DERs is leading utilities to consider enhancements to their approach to load and DER forecasting. Forecasts should evolve to include more granular projections of DER potential and expected customer adoption on different parts of the system, and the resulting effect on load profiles. This includes not just distributed generation but also a comprehensive assessment of the potential for, and effect of energy efficiency, controllable loads (e.g., demand response), smart inverters, energy storage and EVs. These more granular forecasts are also of increasing interest and importance to regional transmission and wholesale market capacity planning, where there are efforts underway to include aggregated DER as resources in wholesale markets.[5]

Load and DER forecasting should include the development of multiple DER scenarios and use probabilistic planning methods to provide a robust understanding of risks and opportunities. This will help address uncertainty with respect to what future loads will look like and what utility investments will be needed as customer energy needs and uses change over time.

Load and DER forecasts will benefit from stakeholder input for building scenario and forecast assumptions. For example, utilities may not have full, up-to-date information about DER costs and performance. Stakeholder input may also help with development of the macroeconomic and other broad assumptions that help define different scenarios. Utilities must be able to weigh these inputs and adopt appropriate assumptions in order to meet their obligations to provide reliable service. Then, assumptions should be shared between different planning activities and planning bodies.

Assessing the Distribution System

Next, utilities evaluate how the existing system would meet future needs through an engineering assessment. Through this process, planners identify areas of system need – where infrastructure investment or system reconfiguration is needed to meet projected demands over the planning horizon. As part of this effort, utilities may also identify the system's capacity to reliably accommodate DER injections in each area, known as hosting capacity. This mapping could also show where certain types of additional DER would most benefit the system (including to increase hosting capacity), including energy efficiency, energy storage and demand response, or areas where the load profile aligns well with the generation profile of a given DER asset and there is a forecasted system need due to load growth during those hours.

Utilities could also identify investments necessary to enable a more integrated grid (e.g., advanced metering infrastructure, distribution automation, or the use of smart inverters). The assessment of the distribution system will also serve to increase transparency for regulators, customers and third parties into the needs of the distribution system and provide greater access to appropriate distribution system data.

HOSTING CAPACITY ANALYSIS

This engineering assessment helps to determine the available electric distribution capacity for interconnecting DERs. For example, the analysis could determine that a certain circuit is at capacity because of high levels of existing customer-sited solar PV in one area, and thus requires upgrades before more DG could be added. Similarly, it could inform customer or third parties as to where energy storage could be valuable to increase hosting capacity. Hosting capacity analyses should focus on the principal system constraints: thermal, safety/reliability, voltage/power quality and protection limits. A variety of approaches are beginning to develop around hosting capacity processes.[6] Smart inverters will also play a significant role in increasing hosting capacity.

One way that utilities can display the information they develop is through heat maps – publicly-available system maps, containing relevant data on the distribution system. California, New York, and Hawaii are among a few states that are currently developing and using hosting capacity maps, updated regularly, to make the data available and actionable to other stakeholders. Regular and increasingly automated updates to hosting capacity maps and other system data provide the most value to developers and DER providers. For example, the California Public Utilities Commission has issued guidance for their utilities to refresh publicly-available hosting capacity maps monthly. As utilities and system operators engage more deeply in DER integration efforts, hosting capacity analyses are expected to become more granular and dynamic, building off the lessons learned from these early efforts. Analyses can expand to assess system issues at the substation, sub-transmission, and transmission levels that are not currently considered today. While hosting capacity maps today identify areas where distributed generation can be added, in the future, maps could evolve to include useful information for the full range of DER technologies, to enhance the ability of utilities to proactively integrate these diverse resources.

INCREASING APPROPRIATE ACCESS TO SYSTEM INFORMATION

A core element of modern distribution system planning processes should be to provide improved transparency and information to customers, regulators, and third parties to facilitate a common discussion and enable non-utility stakeholders to make investments that support grid needs. In other words, the planning process should provide meaningful and useful data for stakeholders, regulators, and customers to support utility efforts to develop more animated DER markets. The information could be made available as part of targeted utility solicitations for DER solutions to meet specific system needs – for example, via non-wires alternatives (NWAs) solicitations[7] – or as part of broader efforts to make certain information continuously available, such as maps identifying areas on the system where certain types of DER would help to support grid needs, as well as hosting capacity information.

As part of NWA solicitations, utilities should provide information about locational needs and the necessary operational characteristics so that DER companies can develop responses that can meet the needs. Providing third parties with timely access to system data can facilitate the planning process as well as execution of utility investment plans that are increasingly expected to rely on NWAs.

Data is critical for stakeholder engagement. Nevertheless, data should be shared in a way that ensures that sensitive system information, company trade secrets or individual customer personal identifiable information are protected.[8]

Operational Integration of DERs

Allowing for DER to be more fully integrated into utility operations will increase DER's value in planning studies. The growth of DER will also have implications for interconnection and interoperability to keep pace with market growth and ensure the reliability of the distribution system.

INTERCONNECTION STANDARDS

A standardized and streamlined interconnection process helps to speed the process of new generator connections, reduces interconnection costs, ensures grid reliability, and avoids undue discrimination and expenses for distributed generation projects.[9] For example, the Minnesota Public Utility Commission is currently in the process of updating their interconnection standards to be more streamlined and transparent.[10] Some proposals in that proceeding include making it easier for small systems (<40kW) to interconnect, a pre-application report for developers to prevent unnecessary applications, an expedited review process for projects that meet certain characteristics, standardized procurement contracts, and moving from paper to digital applications.

It is important to make sure that states have updated interconnection standards that align with industry best practices to ensure the successful integration of DERs on the grid. Interconnection standards may also interact across and between state and federal jurisdictions. Therefore, development of interconnection standards and interconnection processes should include consideration of Federal Energy Regulatory Commission (FERC) standards[11] and regional Independent System Operator/Regional Transmission Organization (ISO/RTO) standards, where applicable.

For technical interconnection standards, well-developed guidance already exists. For example, the Institute of Electrical and Electronics Engineers (IEEE) series 1547 standards address interconnection of DER with the grid. IEEE 1547 provides mandatory functional technical requirements and presents choices about equipment and operating details for compliance with the standard.[12] Regulators and policymakers should also include revisions to standards that relate to smart inverters (under development as part of IEEE 1547), as smart inverter technology is likely to have growing importance in the future.

INTEROPERABILITY STANDARDS

A modern grid relies increasingly on data exchange and two-way communications between a growing number of devices on both the utility-side and customer-side of the meter. Interoperability can be defined as "the capability of two or more networks, systems, devices, applications, or components to share and readily use information securely and effectively with little or no inconvenience to the user."[13] Pursuant to the Energy Independence and Security Act of 2007, the National Institute of Standards and Technology (NIST) facilitated the development of interoperability standards for smart grid technologies.[14] Interoperability crosses jurisdictional, operational, and supply/demand boundaries and should be a core consideration as DERs are integrated into the grid.

GRID MODERNIZATION INVESTMENTS AND DER AGGREGATION

While increased DER penetration does bring with it some challenges, the goal is to establish integration approaches that reduce or eliminate the likelihood that DERs will negatively impact the grid. Indeed, aggregations of multiple DER assets may have a better chance of performing well when paired with grid intelligence than a single large asset. The National Academies recently found that advanced controls and a more distributed energy generation architecture have the potential to prevent or limit widespread electricity grid outages by enhancing power quality and allowing problematic components to be isolated.[15] For example, many advanced energy technologies, like battery storage, fuel cells, or aggregated demand response, can be "instant on," and because of their distributed nature, could immediately provide support to specified areas of the grid in a reliability emergency. Similarly, rooftop solar installations combined with storage and/or active building management systems can provide capacity and ancillary services, and aggregated DERs set up as a microgrid with islanding capabilities may also provide back-up service during outages or could limit the extent of outages, including for critical facilities served by the microgrid.

To ensure that customers can realize these and other benefits, regulators should specify that the distribution system planning process clearly identifies the investments needed to maintain and modernize the grid and effectively integrate the use of DERs. Although not an exhaustive list, the following grid architecture elements should be considered:

Traditional Grid Infrastructure. Continued investments in traditional grid infrastructure, including to enhance resilience, improve the efficiency of the grid, and increase hosting capacity.

System Visibility, Monitoring and Management. Technologies to manage and monitor the distribution grid include: advanced metering infrastructure, advanced and expanded supervisory control and data acquisition (SCADA) systems and sensors, advanced distribution management systems (ADMS), advanced communications systems, smarter and more automated DER monitoring and dispatch systems (i.e., DER management systems or DERMS), self-healing grid capability such as fault location, isolation and service restoration (FLISR) and automated switching, and Geographic Information Systems (GIS).

RTOs/ISOs typically have little to no visibility into the current status of the distribution system. As DERs increase participation in the wholesale market, this lack of visibility may result in the RTOs/ISOs issuing dispatch instructions to DERs that the DERs are unable to comply with due to distribution system constraints, and may contribute to operational problems on the distribution system. Enhancing visibility can alleviate these issues. Visibility includes:

- Increased visibility into DERs (e.g., status and output) for the distribution utility, transmission utility and ISO/RTO.
- Distribution grid status information for DER providers, e.g., DER providers do not have distribution system status information that can affect their ability to export or participate in various markets for DER services.

Integrated grid and data platforms for managing data. Investments that can help to manage and integrate distributed assets including advanced and expanded asset management and predictive analytics tools for things such as:

- Predicting DER behavior
- Viewing real-time DER responses
- Forecasting DERs' impact on the grid

Communications. In addition to the communications networks associated with AMI and other distribution systems, as DER participation in wholesale markets increases, increased coordination and communication between the electric distribution utilities and ISOs/RTOs becomes important, which may also require additional investments.

Cybersecurity Considerations

Cybersecurity is a growing issue for the global economy. As new digital technologies and communications become widespread, cybersecurity is of particular concern to critical infrastructure systems. A modern and more distributed grid will open new modes of communication and interaction between increasingly diverse and numerous participants and devices, creating more potential intrusion points for malicious actors. Efforts are underway to develop and implement practical and effective protections to help secure an increasingly complex, interactive, and distributed electricity system from cyberattacks.[16]

Developing a Framework to Properly Value and Source Services from DERs

In order to evaluate all resources and their various attributes against each other on a level playing field, a regulatory structure should be developed to properly value and source services from DERs. That sourcing can be done in one of three ways, or via a combination of them: procurements, programs, and pricing. Underpinning these approaches is a benefit-cost analysis framework that can evaluate DERs in a comprehensive manner.

BENEFIT-COST ANALYSIS (BCA) FRAMEWORK

First, we recommend the development of an analytical framework in order to adequately compare the costs and benefits of all potential resources against each other in proposed distribution system plans. We encourage regulators to work with utilities and other stakeholders to develop a comprehensive framework that includes evaluation of all supply-side and demand-side resources, as appropriate, given the regulatory model in each state. Using such a framework allows utilities to compare traditional solutions with DER-based solutions, including the potential for a mix or portfolio of such solutions. Such a framework may include consideration of a wide range of technologies and appropriate inclusion of societal benefits consistent with state policy objectives. Hard-to-quantify costs and benefits can also be considered, with the option to use proxies and other methods that can be made more precise over time. This recognizes that simply because a cost or benefit is hard to quantify does not mean that its value is zero. Various states have experience in applying proxies for energy efficiency program assessments that can be brought to bear here.[17] For example, on May 18, 2017, E4TheFuture, published the National Standard Practice Manual (NSPM)[18], which builds and expands on the California Standard Practices Manual (CaSPM) to provide a comprehensive framework to evaluate the cost effectiveness of energy efficiency resources. The NSPM was developed via the National Efficiency Screening Project (NESP), which developed the Resource Value Framework (RVF) to provide guidance for states to develop and implement tests that are consistent with sound principles and best practices, while providing each state flexibility to ensure that the test they use meets their state's distinct needs and interests. New York State, as part of its Reforming the Energy Vision proceeding, has also developed and implemented a BCA framework that includes many of the above-mentioned elements.[19]

PROCUREMENT

In certain circumstances, utilities may be able to meet defined distribution system needs with DER-based solutions, also called non-wires solutions or NWAs. We recommend the development of a competitive solicitation framework to source DER-based solutions at the lowest cost. Competitive solutions maximize customer value and can be streamlined to provide a more expedited DER sourcing process. This method allows the utilities to find the least-cost, best-fit DER solutions based on market response, and to ensure that the benefits of competition accrue to all customers and DER suppliers. Competitive solicitations also provide the utilities with the essential flexibility to target specific locations, sizes, and durations based on the local distribution need, and to expect contracts with creditworthy and reliable counterparties with viable projects.

Any framework should include appropriate compensation mechanisms that incorporate localized incentives targeted at areas of the grid where DER can provide the most value. Additionally, solicitations should include specific performance requirements to ensure the non-wires solution reliably meets system needs. For example, in its integrated DER proceeding,[20] California recently developed a solicitation framework to target their reliability needs identified in their distribution plans. The framework included the development of seven principles:

1. Define the services and resources to be bought and sold within specified areas identified in the initial engineering assessment (i.e., distribution capacity, voltage support, reliability, and resiliency)

2. Develop methodologies to count services provided and to ensure no duplication with procurement in other proceedings

3. Develop solicitation rules or principles (e.g., technology-neutral, least-cost and best-fit resources)

4. Develop solicitation oversight needs

5. Develop solicitation evaluation method (i.e., screening process, valuation process, and selection methods)

6. Develop solicitation pro forma contracts (i.e., payout structure and performance assurances)

7. Develop outreach plans to ensure robust participation in the framework.

PROGRAMS

In addition to NWAs, utilities and third parties can establish programs, such as demand response programs or new competitively-sourced load reduction programs, to meet targeted or general load relief. A good example of such a program is ConEdison's Smart Usage Rewards program in New York that pays participating customers to reduce their energy usage during peak hours in the summer. As different parts of the grid have different constraints, ConEdison offers location-based payments to target load relief on different nodes on their system. Participating customers with over 50 kW of load can enroll directly with ConEdison, while smaller customers can enroll through a participating aggregator. Both receive monthly payments based on the amount of capacity (kW) they pledge to reduce, plus additional payments based on the amount of energy (kWh) reduced.[21]

PRICES

Rules and tariffs can be developed to create a distribution-level marketplace that consumers (including "prosumers", i.e., customers that want to actively participate in energy markets), and third parties, acting on their own or on behalf of their customers, can deploy DER that provides system-wide benefits. An example where this occurs today is where commercial customers implement energy storage to reduce their peak demand, using demand charge savings to help pay for the storage equipment. Where permitted by law, the utility role may evolve more to be that of a platform operator and market manager where DER is being deployed and operated to deliver system benefits. For example, this can include providing access to customer and system data for third-party DER providers so that they can identify areas where DER provides the greatest value. It would also require that regulators consider new rules for how utilities will earn money such as allowing them to create value by more effectively integrating third-party and customer solutions.

As regulators, policy makers and other parties develop these DER sourcing and compensation mechanisms, the following principles should be considered:

1. **Test, Learn and Adapt:** Traditional "poles and wires" solutions have been proven over decades to solve reliability issues. Newer approaches will evolve via an iterative "test, learn, and adapt approach" over a sufficient period to ensure that DER services can similarly solve reliability issues in a cost-effective manner that minimizes adverse impact to customers. All market participants, stakeholders, and local jurisdiction authorities need to learn from those efforts and adapt prior to launching additional, new approaches. Learning from other jurisdictions should also help accelerate this process.

2. **Safe, Reliable and Visible:** The DER sourcing mechanism must be capable of providing the required services at the right time, location, with the right level of certainty, and in the required quantity to satisfy the identified grid need. To fully realize the value of DERs, additional visibility into the grid and DERs is needed to validate this value.

3. **Cost-effective:** The DER sourcing mechanism should be cost-effective when compared to the traditional wires solution on the basis of the investment being deferred and attributes needed for a successful deferral. To the extent societal impacts are considered by regulators, these must be balanced with a consideration of customer bill impacts.

4. **Customer Engagement and Education:** Customers should be able to learn about and understand their options for participating in various programs and offerings. Efforts should be made to avoid customer confusion that may result from having multiple, similar offerings.

5. **Incremental Benefit:** Any sourcing mechanism should ensure that only incremental value is being sourced to avoid double compensation for the same customer benefit.

Interactions With the Bulk Power System

Interactions between what occurs at the distribution level and the bulk power system also need to be considered. On the one hand, enhanced visibility and control at the distribution level can facilitate the integration of larger-scale renewable generation, for example, sending signals to EVs to charge when there is excess renewable generation, or using aggregated demand response to reduce load during a system-wide peak. But if DERs are providing services at both the distribution level and bulk system level, there needs to be coordination so that the resources are available when expected, safety and reliability are maintained, and any regulatory limitations on dual participation are taken into account.

One approach is to establish a **coordination agreement** prior to market participation of DER aggregations. Such an agreement can establish the framework for roles, responsibilities, and accountabilities between the DER aggregator and distribution utility, and can help establish clarity re: available utilization of the distribution system to facilitate ISO/RTO market participation by DER aggregations and any allocation of related costs. Operation of a DER aggregation in response to wholesale market signals should not negatively impact the ability of the distribution system to safely serve all customers. The agreement would specify the DER aggregator's obligations to support the safety and reliability of the system to the utility as a condition for participation and the utility's obligations to the DER aggregator based on the various services its performance characteristics allow.

IMPLEMENTATION

Developing a more transparent, inclusive, and comprehensive distribution planning process, without jeopardizing safety and reliability, that specifically accounts for DER represents a major change from the status quo and will require careful consideration of a variety of factors to be successful. AEE recommends the following steps for any state that wants to update their distribution system planning processes.

Stakeholder Engagement

Through experience in several jurisdictions, we have learned that open and transparent stakeholder collaboration is one of the most important tools for making sure new planning processes succeed. Therefore, we recommend that, to the greatest extent possible, regulators hold open and collaborative proceedings – or develop workshops or voluntary listservs, which can be even less formal – to ensure the most stakeholder input possible and to generate new ideas. This allows regulators to take wide-ranging input and reduces barriers to participation, particularly for stakeholders with limited resources, for whom participation in adjudicated proceedings is difficult.

The process could begin with working groups that focus on developing guidance for utilities to follow when developing their plans and NWA performance requirements. This process will coalesce the stakeholder community around a shared vision of what the distribution system plans should look like. Development of the plans and implementation can then proceed more smoothly once this foundation has been laid. During development of the plans, transparency and stakeholder input are also crucial. System and customer data, modeling assumptions, and modeling scenarios should be shared such that stakeholders may provide valuable feedback for solutions to problems, utilities can identify opportunities to use DER to solve system needs more affordably and effectively, and regulators can gather input from all parties to understand their views and the potential effects of any decisions.

Integration With Other Planning Activities

Distribution system planning should be integrated with and inform other planning activities including, as applicable, integrated resource planning (IRP), transmission/wholesale market planning, interconnection, and grid modernization.[22] The growth of DER on a utility's distribution system may alleviate the need for new centralized generation and/or transmission and may also provide the opportunity for NWA projects that can substitute in certain circumstances for traditional utility distribution system solutions. Rising DER deployment also has implications for the types of distribution system and other investments that will be needed. Therefore, planning processes at all levels should take various DER growth forecasts and options into account and drive towards decisions that are optimal for the system as a whole and for customers.

Furthermore, this integration with other planning activities would also be useful to identify opportunities for improving coordination between the transmission and distribution planning processes. This planning coordination may identify potential operational restrictions and/or necessary investments that the utilities may require for DER aggregations to participate in multiple markets or may suggest modifications that DER aggregators could make to mitigate identified problems. In addition, this integration of planning activities could help identify any potential DER dispatch conflicts associated with DER aggregation. For example, if a DER aggregation is contracted to provide distribution services to a distribution utility, such as discharging energy back to the grid during local distribution peak periods, those obligations should not conflict with how the ISO/RTO is planning to dispatch the DERs. The coordination may also help identify potential changes to distribution utility maintenance schedules to ensure that DERs are available to meet their obligations in wholesale markets.

In developing distribution system plans, policymakers, regulators, utilities, and other stakeholders should think through the different ways in which the plans may be used so that they have the right outputs and level of detail to be helpful for other planning processes or policy goals. For example, if the goal is to identify NWA opportunities, then plans should contain sufficient information about distribution system loads, load forecasts and conditions, such that DER providers can propose solutions that will meet system needs. If the goal is to reduce costs and greenhouse gas emissions, then DER forecasts should be incorporated into integrated resource planning to inform capacity planning and modeling assumptions.

A "Walk-Jog-Run" approach

We recognize that each state and even individual utilities within a state are at different stages of DER penetration and level of sophistication with respect to using various planning tools. As such, distribution system planning and its integration with other planning processes are best done in an evolutionary approach, so as to better align with the pace of industry and system changes, such as rates of DER adoption, evolving customer needs, and alignment with state policy goals. MoreThanSmart advocates for a "Walk-Jog-Run" model[23] to characterize investment stages and states of DER penetration to guide transition of distribution system plans.

- "Walking" primarily involves anticipating changes.
- "Jogging" involves more advanced analyses, usually due to increased DER penetration.
- "Running" may involve more complex analyses based on a higher penetration of DERs and sophisticated data collection and analysis, which can inform system-wide decisions.

To illustrate these phases, "Walking" may mean initiating DER hosting capacity analyses and improving interconnection processes and operational enhancements, "Jogging" may entail developing a framework to value and source services from DERs, and "Running" may involve using distribution system planning outputs to inform integrated resource plans and/or transmission planning.

CONCLUSION

Distribution system planning that proactively plans for more distributed assets at the grid edge will help chart a path to a 21st century electricity system. Utilities should factor into their planning the fact that DER penetration is increasing, with or without public policy support. Load forecasting, scenario planning, and other aspects of distribution system planning need to take these customer choices into account. To help achieve the most cost-effective solutions, utilities will need to offer appropriate visibility into their distribution systems, as well as their monitoring and communications capabilities. Stakeholders must understand and anticipate decisions to deploy DER, their impact on the system in terms of both benefits and costs, and their effect on other planning activities. This will improve condition assessments so that utilities can operate the system more efficiently and plan for upgrades that will increasingly enhance the distribution system's capabilities. If done properly, a framework will emerge that will lead to a more flexible, reliable, resilient, cost-effective, and clean electricity grid.

ENDNOTES

[1] For purposes of this issue brief, "regulators" means state public utility commissions and other state and local governing bodies, such as a city council or independent utility board in the case of municipal utilities.
[2] http://info.aee.net/21ces-issue-briefs
[3] Advanced Energy Economy (AEE) is comprised of a diverse membership. As such, the information contained herein may not represent the position of all AEE members.
[4] Staff, Minnesota Staff Report on Grid Modernization, MPUC, March 2016.
[5] https://www.aee.net/articles/aee-applauds-ferc-action-on-energy-storage-ders
[6] See, e.g., California's DRP (http://www.cpuc.ca.gov/General.aspx?id=5071) and The Electric Power Research Institute's Integration of Hosting Capacity Analysis into Distribution Planning Tools at: https://www.epri.com/#/pages/product/000000003002005793/; additional resources at http://dpv.epri.com/hosting_capacity_method.html
[7] NWAs use DERs to meet forecasted higher capacity needs rather than traditional investment in wires, transformers, and substations.
[8] For more details on a recommended data access framework see our Issue Brief on Access to Data, available at http://info.aee.net/21ces-issue-briefs
[9] Rauch, Jason N. Renewable Generator Interconnection. U.S. Agency for International Development/National Association of Regulatory Utility Commissioners. March 24, 2014. Accessed June 19, 2017. URL: http://pubs.naruc.org/pub/5381D31C-2354-D714-51ED-08FD965CF29D
[10] MPUC Proceeding 16-521, (URL NEEDED)
[11] For example, FERC Orders 2003, 2006, 661; Standard Interconnection Agreements and Procedures for Small Generators https://www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp
[12] For more information, see Basso, Thomas S. IEEE 1547 and 2030 standards for distributed energy resources interconnection and interoperability with the electricity grid. Vol. 15013. National Renewable Energy Laboratory, 2014. URL: http://www.nrel.gov/docs/fy15osti/63157.pdf
[13] U.S. Department of Energy. Smartgrid.gov - What is the Smart Grid: Standards and Interoperability. Accessed June 19, 2017. https://www.smartgrid.gov/recovery_act/overview/standards_interoperability.html
[14] U.S. Department of Energy. Smartgrid.gov - What is the Smart Grid: Standards and Interoperability. Accessed June 19, 2017. https://www.smartgrid.gov/recovery_act/overview/standards_interoperability.html
[15] National Academies of Sciences, Engineering, and Medicine, "Enhancing the Resilience of the Nation's Electricity System" (Washington, DC: The National Academies Press, 2017).
[16] For more details see our white paper, Cybersecurity in a Distributed Energy Future, available at https://info.aee.net/aee_institute_cybersecurity
[17] In September 2014, Synapse Energy Economics prepared a report for AEE Institute titled Benefit-Cost Analysis for Distributed Energy Resources: A Framework for Accounting for All Relevant Costs and Benefits. In this report,17 AEE Institute proposed a benefit-cost framework for New York state; however, much of the report is broadly applicable to other states.
[18] https://nationalefficiencyscreening.org/national-standard-practice-manual/
[19] Order Establishing the Benefit Cost Analysis Framework, January 21, 2016. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={F8C835E1-EDB5-47FF-BD78-73EB5B3B177A}
[20] CPUC Proceeding R.14-10-003, Decision 16-12-036 December 15, 2016.
[21] https://www.coned.com/en/save-money/rebates-incentives-tax-credits/rebates-incentives-tax-credits-for-commercial-industrial-buildings-customers/smart-usage-rewards

[22] We support an integrated system planning approach, along the lines of the report on integrated distribution system planning prepared by ICF International. ICF International. Integrated Distribution Planning: Prepared for the Minnesota Public Utilities Commission. U.S. Department of Energy. Washington, DC, 2016. Accessed June 15, 2017.
https://energy.gov/sites/prod/files/2016/09/f33/DOE%20MPUC%20Integrated%20Distribution%20Planning%208312016.pdf

[23] De Martini, P., Brunello, T., and Howley, A. Planning for More Distributed Energy Resources on the Grid: A Summary for Policymakers on the Walk-Jog-Run Model. MoreThanSmart. Oakland, CA. 2016.