BUILDING A SMARTER ELECTRIC GRID

HOW INVESTING IN SMARTER ELECTRICITY INFRASTRUCTURE WILL ENERGIZE AMERICA

PREPARED BY

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EXECUTIVE SUMMARY

Access to affordable, reliable energy is the cornerstone of a strong economy and first-world living standards. The U.S. electric grid has served as the backbone of the U.S. economy, expanding and evolving along the way. As new energy technologies continue to emerge and growing amounts of distributed energy resources ("DER") come online, the grid will serve as a critical enabler of these technologies.

The potential benefits of a smarter, more distributed grid are well-established, including a reduced carbon footprint, increased efficiency, and reliability and resiliency improvements. But creating multidirectional flow on a grid that was designed primarily to deliver power in one direction, while also improving the system's capability to integrate increased amounts of distributed resources, is a costly and complex challenge. Without well-planned grid infrastructure improvements that provide increased visibility and management, these and other challenges could negatively impact system reliability and resilience, and put additional stress on existing infrastructure, e.g., power lines, transformers, substations, control systems, etc. Finally, the increased interconnectedness and complexity of the emerging grid model may create new cyber vulnerabilities.

Many electric utilities and grid operators have made investments to further modernize their systems to ensure smart grid and DER technologies are properly integrated and contribute to enhancing the resiliency and reliability of the grid. And while many stakeholders, including utilities and other market participants, are actively investing in deploying these new technologies, such development is uneven, and in aggregate may fall short of what is needed to fully realize the benefits of the "DERready" smart grid.

This paper identifies priorities for additional future investment to help companies and governments smooth the transition to a more digitized grid and safely and efficiently integrate DER, including rooftop solar and other distributed generation ("DG"), energy storage, electric vehicles, and other advanced energy technologies (e.g., smart hardware, software, and analytic capabilities). Specifically, this paper recommends that state and federal regulators and utilities consider undertaking the following investments, modifications, and practices:

- **Enhanced foundational infrastructure:** Investments in overhead and underground lines with conductors and cable with sufficient capacity are necessary to facilitate the movement of power to and from forecasted increases of DER.

- **Advanced protection, distribution automation, and advanced metering infrastructure (AMI):** Widespread variable DG adoption, particularly photovoltaic (PV) systems, is transforming distribution systems from passive grids to dynamic networks. This type of system requires increased visibility, observability, awareness, and management in real-time. Needed investments include deployment of advanced reclosers, distribution automation switches, advanced sensors, modern voltage control/regulation devices, and AMI (i.e., smart meters).

- **Communications infrastructure:** Additional investment is needed to ensure data collected in the field can be sent to utility control centers, distributed controllers, and information systems, and control decisions communicated back to field devices in real-time. Current distribution systems either do not have two-way communications infrastructure with enough bandwidth and reliability to collect data and implement control actions, or their coverage is limited to distribution substations and a few critical components.

- **Advanced control/management systems and grid analytics:** Controlling an active and dynamic distribution grid requires advanced control and management systems and applications with advanced algorithms that can process the data collected in the field to make intelligent control decisions aimed at optimizing real-time distribution system performance, including Distribution Management Systems (DMS), Outage Management Systems (OMS), Distributed Energy Resources Management Systems (DERMS), and more.

- **Distributed Energy Storage (DES):** Increased deployment of DES will help manage the reliability challenges that arise when integrating increased amounts of variable DG into distribution grids.

INTRODUCTION

A. Overview of the Evolving Electricity Sector

The advent of new technologies and the increased deployment of distributed energy resources ("DER") have spurred speculation and debate regarding the future of the U.S. electricity system. The debate goes far beyond the mainstream energy discourse of fossil fuel versus renewable energy generation. Rather, it centers upon something much more fundamental: the very design of how electricity should be generated, delivered, and consumed. At the heart of this issue is the speed and scope with which the Nation's electricity system will shift from the current centralized model to an increasingly decentralized one.

The traditional or centralized model has evolved since Thomas Edison introduced the first central power station,[1] but the basic structure is relatively unchanged: generate electrons at a central power plant, transmit them over a unidirectional system of high-voltage transmission lines, and deliver them to consumers through local distribution networks. Of course, there's nothing simple about delivering electricity in real-time to millions of people. A sophisticated system, backed by complex engineering and hundreds of thousands of component parts, supports the traditional model, keeping supply and demand in constant balance down to the millisecond in order to keep the lights on.

The emerging, more decentralized model is less reliant on the central power station as the primary provider of electricity. Instead, this model envisions an integrated network of various distributionlevel technologies (e.g., DER, energy storage, electric vehicles, microgrids, and demand-side management

1 In 1882, Edison Electric Illuminating Company began operation the Pearl Street Station in New York City, the first central power plant in the United States. Bosselman, et al., ENERGY, ECONOMICS AND THE ENVIRONMENT at p. 566 (3rd Ed. 2010).

technologies, etc.) that would allow for the bidirectional or multidirectional flow of electrons, the use of sophisticated energy usage, pricing, and load management software, connected appliances and vehicles, and improved communications between producers, consumers, devices, and systems.[2]

The two models are not mutually exclusive. The most resilient smart grid likely will be a centralized-decentralized hybrid. While it is apparent that the way in which electricity is produced, delivered, and consumed will differ from today's traditional model, the fundamental design and engineering that makes up today's electric grid will serve as the foundation for achieving a more distributed future.

B. What's Powering this Evolution?

Smart grid deployment efforts have gained momentum in recent years for a number of reasons, ranging from economics, technological advances, environmental considerations, and public policies to changing consumer needs and expectations.

While environmental considerations and consumer expectations are more difficult to quantify, technological breakthroughs in the distributed space are more straightforward. Rooftop solar systems, energy storage technologies, and electric vehicles have all benefited from improved efficiencies. Further, breakthroughs in the hardware, software, and communications systems that support distributed technologies have been critical to increasing deployment.[3] Advances in information and communications technologies have led to intelligent energy platforms that are capable of sharing information among grid components in real-time, automating grid operations, serving load management functions, and using energy analytics to improve system efficiencies and provide consumers greater transparency into usage and pricing.

These technological improvements combined with economies of scale, and state and federal tax incentives, grants, and mandates are putting downward pressure on the installed cost of residential solar and other DER technologies. These lower costs have led some consumers to take better inventory of their choices, whether for environmental reasons or because it makes good economic sense.

2 The emerging model also contemplates greater deployment of utility-scale renewables and utility-scale energy storage.

3 Navigant, Inc., "The Energy Cloud: Emerging Opportunities on the Decentralized Grid," (2016).

But, increasingly, there's another trend driving consumer interest in distributed energy resources and related products – changing expectations about how they interact with all services across industry sectors. Platforms like Uber, Netflix, and Airbnb, gave consumers significantly greater control over the products and services they consume. Some consumers have carried these expectations into the energy sector, calling for greater control over their energy use and what they pay for it. From rooftop solar, residential energy storage, microgrids, net zero homes, community solar, and smart appliances, a literal "power to the people" mentality is beginning to take shape among electricity consumers.

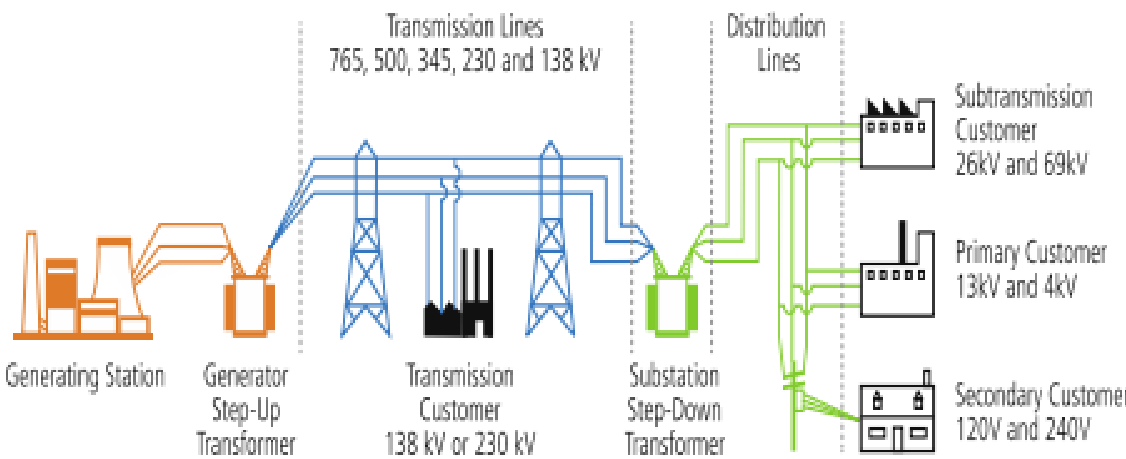
THE GRID

A. What is The Grid and How Does it Work?

The U.S. electric grid – the interconnected network of power generating stations, transformers, transmission lines, substations, and distribution lines – is a highly complex, highly engineered system responsible for delivering safe, reliable, and affordable electricity to 159 million residential, commercial, and industrial customers.[4] While commonly thought of as one integrated system, there is actually no nationwide electric grid. There are three separate systems, referred to as "interconnections" across the U.S. (excluding Hawaii and Alaska).

Structurally, the traditional grid model is primarily a unidirectional system that depends on centralized utility-scale generation, from which electricity is transmitted long distances, routed through a substation, and distributed to customers (see Figure 1).

Figure 1:Traditional Grid [5]



4 See U.S. Department of Energy, "Quadrennial Energy Review Second Installment – An Integrated Study of the Electricity System", pp. 3-3 to 3-4. (April 2015). This source defines "customer" as any entity consuming electricity at one meter, including factories, commercial entities and residences. As a basic rule of thumb, each residential electric meter serves 2.5 people.

5 See U.S. Department of Energy, "Quadrennial Energy Review Second Installment – An Integrated Study of the Electricity System", (April 2015) (Image sourced and adapted from North American Reliability Corporation

However, the grid is by no means simple. There are more than 3,300 electricity providers generating more than 4 terawatt-hours of electricity from 19,000 individual generators at roughly 7,000 power plants[6] delivered to customers across the U.S. through more than 642,000 miles of high-voltage transmission lines and 6.3 million miles of distribution lines.[7] Making matters even more complex, these interconnections are operated by seven Regional Transmission Organizations and Independent System Operators, thousands of electric providers ranging from publicly-owned utilities and electric cooperatives to investor-owned utilities, independent power producers, and federal power agencies.

Building and managing grid infrastructure requires extensive planning to ensure generation meets demand, determine what type of generation assets to build, and where to place these assets, as well as transmission lines, to ensure reliability and minimize power losses during delivery.[8] Providers must also account for the transformers needed to increase the voltage for efficient long-haul transmission from generation to the substation.[9]

The movement of energy from generation to distribution substations also requires constant monitoring. NERC explains:

> ***[e]lectricity flows simultaneously over all transmission lines in the interconnected grid system in inverse proportion to their electrical resistance, so it generally cannot be routed over specific lines. This means generation and transmission operations in North America must be monitored and controlled in real time, 24 hours a day, to ensure a reliable and continuous supply of electricity to homes and businesses.***[10]

6 "Power Plants" as used for this purpose are facilities with at least 1 MW of generating capacity.Navigant, Inc., "The Energy Cloud: Emerging Opportunities on the Decentralized Grid," (2016).
See American Public Power Association, 2015-2016 Annual Directory & Statistical Report, "U.S. Electric
7 Utility Industry Statistics", and U.S. Department of Energy, "Quadrennial Energy Review Second Installment – An Integrated Study of the Electricity System", pp. 3-3 to 3-4. (April 2015).
8 As a general rule, the further the power needs to travel from generation to the end user, the more electricity will be lost along the way (This is not always the case; especially in less populous states where the power can travel further on more efficient high-voltage transmission lines.) Depending on the state, power losses range from 2.2 percent to 13.3 percent during transmission and distribution alone. Inside Energy, Jordan Wirfs-Brock, "Lost in Transmission: How Much Electricity Disappears Between a Power Plant and Your Plug?". Accessed January 5, 2017.
9 See U.S. Department of Energy, "Large Power Transformers and the U.S. Electric Grid", p. 5 (June 2012)
10 North American Reliability Corporation, "Understanding the Grid", (December 2012)

After distribution substations receive the energy from high-voltage transmission lines, they reduce the voltage so it can be safely sent to consumers. However, even after the power leaves the substation, power is sent through a complex system of circuits and switches, and thousands of additional transformers, to ensure voltage is safe and appropriate for the power's intended end-use. The U.S. Department of Energy explains:

> ***Several primary distribution feeder circuits, connected by an array of switches at the distribution bus, emanate from the substation and pass through one or more additional transformers before reaching the secondary circuit that ultimately serves the customer. One or more additional transformers reduce the voltage further to an appropriate level before arriving at the end-use customer's meter.***[11]

B. Transitioning to a Smarter Grid

As new technologies become more prevalent in the energy sector, electric utilities and grid operators need to further integrate advanced hardware and software components to make the grid smarter without sacrificing the reliability consumers expect. The grid's basic structure will remain the underlying commonality, but the resulting smart grid will need to account for an integrated network of increasing distribution-level technologies that would allow for the bidirectional or multidirectional flow of electrons, the use of sophisticated energy usage, pricing, and load management software, connected appliances and vehicles, and improved communications between producers, consumers, devices, and systems. Specific distribution-level technologies include:

- Distributed Energy Resources
- Microgrids, Community Solar, and Virtual Power Plants
- Plug-in Electric Vehicles
- Smart IT Hardware, Software, and Energy Analytics
- Demand Response and Demand-Side Management

Numerous benefits are expected to be gained as these and other emerging technologies continue the transition to a smarter grid, including:

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[11] U.S. Department of Energy, "Quadrennial Energy Review Second Installment – Transforming the Nation's Electricity System", Appendix A, p. A-6. (January 2017).

- **Economic and environmental benefits through system-wide efficiency:** Smart energy infrastructure and related technologies will reduce overall demand by managing consumption, and strengthening reliability and power quality for customers, while improving downstream visibility and management for grid operators. On the supply side, deployment of smart energy technologies can improve efficient utilization of available installed capacity, through peak shaving and load shifting. Further, more localized DER paired with analytics and communications technologies will reduce line loss by limiting the distance electricity travels when possible. On the demand side, intelligent dispatch of grid-connected DER to supply local demands and support the grid when needed (e.g., during peak demands), which in turn could help defer or reallocate capital investments. These efficiencies bring environmental benefits as well. More efficient use of installed generation capacity will reduce fuel consumption, resulting in decreased greenhouse gas and hazardous air pollutant emissions.

- **Resiliency, reliability, hardening and security benefits:** Resiliency is a broad concept that encompasses reliability, hardening, and physical and cyber security. Resiliency is crucial given the growing importance and criticality of grid infrastructure in the digital economy. The coordinated deployment of some of the new technologies discussed in this paper, particularly grid-connected DER and distribution automation, along with foundational infrastructure, can further enhance service resiliency to the benefit of all customers.

- **Meeting consumer needs and expectations:** Deployment of new technologies can also help fulfill consumer expectations by offering new and additional services to meet evolving needs. Examples include energy efficiency improvements, PEV charging, integration and management of behind-the-meter resources, reliability and power quality enhancement, better understanding of consumption patterns, and service portfolio diversification, etc.[12] For instance, results of a recent industry survey aimed at exploring interest among consumers in additional energy-related products and services show significant interest in new technologies, including behind-the-meter DER, and home automation solutions.[13]

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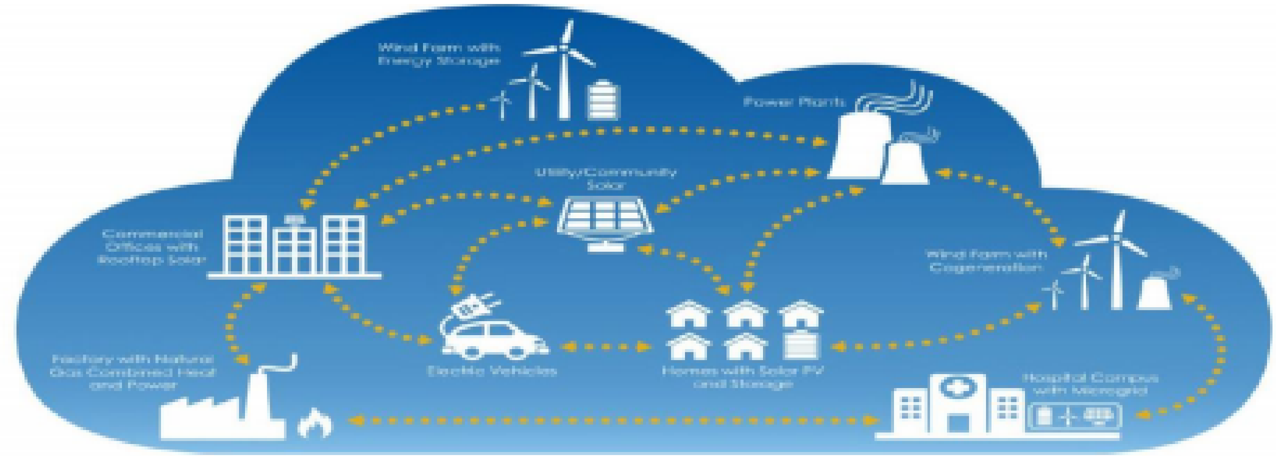
12 Accenture, "The New Energy Consumer: Architecting for the Future" (2014).
13 Ibid.

While most modernization will occur on the distribution side of the grid, aggregation of DER to the transmission grid means the smart grid will need to accommodate multidirectional energy flow on long-distance transmission lines as well. Compare Figure 2 (below) with Figure 1 (above).

Figure 2: Smart Grid[14]



Facilitating the movement of power to and from these resources also requires that the grid "know" when to draw power from certain sources and deliver to others. The U.S. Department of Energy explains:

> ***This communication network will support the ability to monitor and control time-sensitive grid operations, including frequency and voltage; dispatch generation; analyze and diagnose threats to grid operations; fortify resilience by providing feedback that enables self-healing of disturbances on the grid; and evaluate data from sensors (such as phasor measurement units) that enable the grid to maximize its overall capacity in a dynamic manner.***[15]

The smart grid will need to accomplish all of this – i.e., efficiently capture and distribute DER, minimize power line loss, provide better visibility in consumption trends and real-time pricing, and integrate automated systems that push consumption outside of peak demand hours. This would come in addition to what it already does – provide reliable, affordable around the clock energy to meet the country's industrial, commercial, and residential needs.

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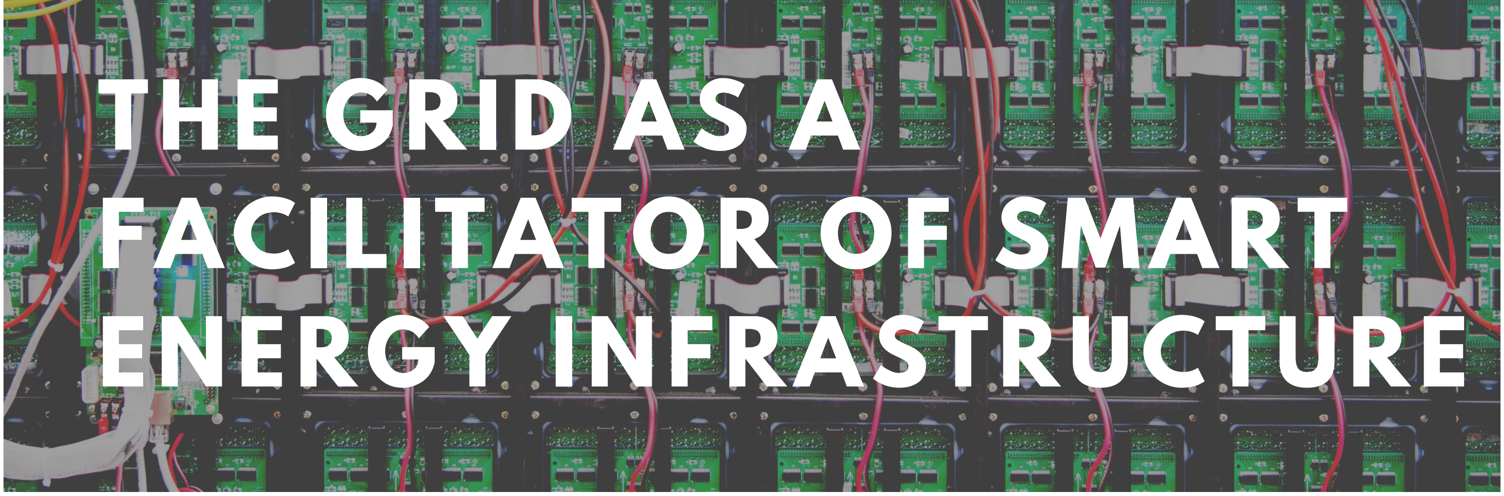
14 Navigant Consulting, "The Energy Cloud, Emerging Opportunities on the Decentralized Grid", p. 8 (2016).

15 Ibid.



THE GRID AS A FACILITATOR OF SMART ENERGY INFRASTRUCTURE

The last decade has seen an unprecedented emergence of smart energy technologies applied to the energy grid generally and distribution systems specifically. Subsection A of this section reviews some of the most important new technologies. Subsection B discusses their impacts on planning, operations, and engineering aspects and the importance of the grid to fully take advantage of the potential benefits derived from their adoption.

A. Emerging Smart Energy Technologies Overview

This section provides an overview of key features and applications of the most common emerging technologies being used in distribution systems.

1. Distributed Energy Resources (DER):

DER consists of relatively small generation and storage technologies interconnected directly to distribution systems, i.e., close to end-users' demands. DER are usually classified in two groups – Distributed Generation (DG) and Distributed Energy Storage (DES). DER, particularly DG assets, are already intrinsic components of modern power distribution systems. Engineering design of distribution grids is still slowly being updated to prepare for seamless DER integration on a larger scale, while planning and operations practices are evolving at a faster pace. DER proliferation is mainly driving the implementation of intelligent infrastructure to understand and, if possible, control system performance, as well as drive deployment of additional foundational infrastructure to mitigate potential impacts associated with DER integration.

a. Distributed Generation (DG):

DG consists of small generation facilities (usually smaller than 20 MW) that are interconnected directly to medium-voltage (e.g., 12.47 kV) or low-voltage (e.g., 240 V) distribution systems. Within this range, DG can be broken into three categories: utility-scale (generally greater than 1 MW); commercial (commonly between 10 kW and 1 MW); and residential (usually smaller than 10 kW). These generation resources can be conventional (e.g., diesel, natural gas, etc.) and renewable (e.g.,solar, wind, etc.) technologies. The most common DG technologies are solar photovoltaic (PV), such as residential rooftop PV, along with conventional DG, followed by other renewable and emerging technologies, such as wind, biomass/biogas, small hydro, and fuel cells, etc. Traditional applications of DG consisted of backup generation to supply important loads during service interruptions caused by grid outages, while modern applications consist of grid-interconnected operation that allow DG owners to sell power to the utility system during normal grid operation.

b. Distributed Energy Storage (DES):

DES consists of energy storage technologies that are interconnected directly to medium or low voltage distribution systems. Like DG, DES can be classified as utility-scale, commercial, and residential. There are a wide variety of energy storage technologies, including Battery Energy Storage Systems (BESS), thermal energy storage, flywheels, supercapacitors, etc. The most popular DES technology is BESS, which utilize batteries based on numerous chemistries, such as lithium-ion, sodium sulfur, lead acid, flow batteries (vanadium redox), and etc. DES is becoming increasingly popular to facilitate the integration of variable renewable DG by compensating for the output variations from solar PV and wind technologies and effectively helping make them more controllable and predictable. DES is also a backup solution for critical and sensitive loads that require high reliability and power quality service.

c. Community Solar:

Community solar consists of a community, utility, or third party-owned solar PV plant whose power production is shared by a community, instead of a single household, thereby eliminating the need to install solar panels on individual properties. Although not usually thought of as DER, community solar is typically deployed at the distribution level and is therefore included in this section as a DER technology. It is also worth noting that while solar is the most common type of “community” DER, other community-based technologies are also emerging, including non-solar generation resources and storage.

2. Microgrids:

The U.S. Department of Energy defines a microgrid as “a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected or island-mode.”[16] Microgrids are increasingly being used to integrate DER over a well-defined geographic footprint, such as a university campus, to take advantage of their potential to improve the resiliency, reliability, power quality, sustainability, efficiency, and the economics of the area.

Key components of a microgrid include DER, distribution assets (e.g., lines, transformers, etc.), load, protection and automation equipment (e.g., switches, relays, etc.), communications infrastructure, and control equipment. The controller is the “brain” of the microgrid and is responsible for determining the “optimal” output from the respective DER and consumption from controllable loads to achieve the appropriate generation-to-consumption balance within the microgrid footprint.

Grid-connected microgrids can improve system-wide efficiencies by, among other things, minimizing losses, maximizing output from renewable DER, and maintaining a predictable and controllable power flow at the point of interconnection with the grid. Island-mode operation may be sustained or temporary; the former is common at microgrids operating in remote off-grid locations, while the latter is intended to improve the resiliency and reliability of the microgrid footprint during service interruptions caused by grid outages.

3. Plug-in Electric Vehicles (PEV):

PEV penetration of personal and commercial vehicles has increased in recent years. The proliferation of this technology has important implications for distribution systems given that PEV charging requirements may represent a significant new load that the grid was not originally designed to supply. Most common PEV are either plug-in hybrid or full battery. Experience indicates that PEV tend to proliferate in clusters, for instance, in specific neighborhoods of large metropolitan areas, and that PEV charging timing may coincide with existing peak load time of residential feeders, e.g., in the evening when commuters return home, which can pose challenges to distribution systems.

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16 Berkeley Lab, “Microgrid Definitions.” Accessed February 6, 2017.

Conversely, PEV batteries can act as DES, helping to manage a household or commercial property's demand on the grid during peak hours. In this scenario, smart meters and software applications allow the property to draw from the battery during peak load hours and recharge the battery in times of low demand.

4. Smart IT Hardware, Software, and Energy Analytics:

One of the key developments of the last decade in the operation of distribution systems is the extensive and ongoing deployment of smart meters, distribution automation, and distribution management systems, driven by smart grid and grid modernization initiatives. The implementation of these software applications and information systems, the hardware that supports them, and the convergence of operations and information technologies are also changing the way distribution systems are being operated and analyzed.

a. Smart IT Software and Hardware:

Collecting, storing, and processing the large volumes of data provided by advanced sensors and smart grid technologies requires the deployment of communications system infrastructures at distribution feeder and end-user level (e.g., fiber optic cable, radio, microwave, Wi-Fi, etc.), as well as utility enterprise systems, such as modern customer information systems, workforce management systems, and meter data management systems. Historically, it was unnecessary to monitor or manage distribution systems in real-time with such granularity for reliability purposes, nor was it technologically or economically feasible. Seamless data collection, processing, and utilization to manage the distribution system also require:

- **Integration of information systems and technologies, so they can share data seamlessly;**
- **Prevention and resolution of data integrity issues via automatic updates of system changes;**
- **Interoperability among sensors, technologies, and systems involved in the process; and**
- **Compliance with cybersecurity requirements to prevent potential vulnerabilities that may compromise data integrity and security. (It is important to note here that uniform cybersecurity requirements do not exist for DER).**

b. Energy Analytics:

Energy analytics (or energy big data) focus on developing solutions to process the plethora of data collected by smart hardware and software to gain greater insight into variables that govern distribution system performance and operations, such as end-user consumption patterns, frequency and duration of service interruptions, etc. Energy analytics can identify solutions to increase overall distribution system operational efficiency and performance, including enhanced asset management, outage management, etc.

5. Demand Response (DR) and Demand-Side Management (DSM):

DR and DSM refer to technologies and solutions aimed at influencing and modifying energy consumption patterns to meet specific planning and operational objectives. Home automation solutions, such as smart thermostats and home energy management systems are expected to become an increasingly important resource to manage the volatility and dynamic behavior of future distribution systems. Examples include using DR for “peak shaving” to better match customer demands and generation resources to prevent potential generation deficits, the utilization of more expensive generation, preventing distribution lines and transformer overloads, and deferring capital investments needed to increase installed capacity.

DR can be implemented under different agreements and technologies, but generally requires that utilities or aggregators be granted control over specific customer equipment, so it is temporarily “disconnected” from the grid to reduce overall system demand when needed. DSM aims at influencing end-users to modify consumption patterns, typically through financial incentives, such as time-of-use rates, to either consume less energy during peak time or shift energy consumption to off-peak time. The proliferation of solar PV DG and energy storage, smart meters, and the growing ability to monitor and control the grid in real-time is providing additional options for implementation of DR and DSM.

B. The Grid Becomes Increasingly Critical to Promote and Incorporate Smart Energy Technologies

This section discusses the importance of the grid – particularly the distribution grid – in facilitating the successful integration of increasing amounts of smart energy technologies and, where applicable, details improvements that can be made to meet or mitigate challenges that may arise as penetration of these technologies increases. This is illustrated through a series of use cases that discuss key aspects, challenges, and experiences pertaining to the application of emerging technologies.

1. Use Case: Impact of DG on Distribution Grids:

This case discusses challenges associated with integrating solar PV into distribution grids. As explained in Section II, most distribution systems in the U.S. were designed to operate in a unidirectional fashion. As such, most existing distribution system equipment and components, as well as engineering, planning, and operational practices, have been developed around this basic assumption. The interconnection of DG technologies with distribution systems challenges this basic assumption by creating a multidirectional system. Consequently, depending on the characteristics of the DG technology and host distribution system (e.g., DG installed capacity, technology, and point of interconnection, feeder voltage and loading, etc.), this can have several impacts that need to be mitigated to ensure seamless integration and continued reliability. In the specific case of variable renewable DG, such as solar PV and wind, an additional challenge is introduced by the output variability of DG, which can lead to additional operational challenges.

Two important concepts necessary to understanding DG impacts on the distribution system are penetration level and hosting capacity. Penetration level is a measure of the balance between DG and load in a distribution feeder or substation; it is usually defined as the ratio between the installed capacity of DG and the peak demand of the feeder or substation. More simply, the maximum amount DG that can be produced at any given time compared to the maximum amount of energy that this particular substation will be asked to provide at any time. Hosting capacity is usually defined as the maximum amount of DG that can be interconnected to a distribution feeder or substation without causing systemic violations of key operations and planning variables, such as maximum voltage or equipment rating. The severity of expected impacts increases as DG penetration levels grow (under a constant hosting capacity scenario). Hosting capacity can be increased through mitigation measures such as distribution system reinforcements and implementation of smart solutions, including using advanced inverters.

The most common impacts associated with DG interconnection in distribution systems include:

- **Voltage increase:** DG integration may change feeder voltage profiles and lead to voltage increase and potential voltage violations, particularly at the DG point of interconnection. Operation at voltages above allowable limits may represent a liability for electric utilities, since it can impact performance or damage utility and customer equipment.

- **Voltage fluctuations:** Variable DG output (e.g., solar PV and wind) can change significantly due to clouding and wind speed variations. This can modify feeder power flows, create voltage drops, and eventually lead to voltage fluctuation that may affect quality of service and generate complaints from customers.

- **Reverse power flow:** When the amount of DG interconnected to a distribution feeder or substation exceeds the respective load, then power may change direction and flow from and to the substation and sub-transmission/transmission system. This can represent a challenge for voltage regulation and control equipment and protection systems needed to maintain reliability.

- **Equipment loading increase:** If the magnitude of the reverse power flow through a distribution asset (e.g., line, transformer, etc.) caused by DG proliferation exceeds that of the original pre-DG interconnection forward power flow, then that asset's loading has increased because of the DG integration. If the increase is large enough, then it can lead to equipment rating violations and potential equipment life-cycle reduction, deterioration, or damage.

- **Losses increase:** If the magnitude of the reverse power flow through a distribution asset caused by DG proliferation exceeds that of the original pre-DG interconnection forward 13 power flow, then power and energy losses associated to that asset will increase with respect to the base scenario and impact overall distribution system efficiency.

- **Interaction with voltage regulation and control equipment:** Voltage fluctuations caused by DG variability can lead to frequent operation of voltage regulation and control equipment (e.g., load tap changers, voltage-controlled capacitor banks, and line voltage regulators). The incremental wear and tear may result in more frequent maintenance needs and costs for utilities and eventually impact equipment life-cycle, increasing costs to customers.

- **Reactive power fluctuations:** DG interactions with voltage-controlled capacitor banks may lead to frequent switching on/off operations that can create sudden changes in reactive power flows. If such changes are systemic and affect numerous capacitor banks over a large distribution system footprint, then they may end up impacting subtransmission/transmission systems as well.

- **Power factor modification:** Most DG plants operate at "unity power factor" to maximize the amount of active energy (MWh) delivered to the system since this is the variable used for DG revenue calculation.[17] Therefore, as DG penetration levels increase, the active power delivered by the feeder and substation decreases, while the respective reactive power remains constant. This effectively decreases the feeder and substation power factor, which can lead to economic penalties for utilities and customers that are required to maintain system power factors above a predefined threshold for reliability reasons.

- **Voltage and current imbalance:** Most residential utility customers have single-phase service (120/240 V), meaning that proliferation of residential DG, particularly rooftop PV, which is also largely single-phase, can increase current and voltage imbalance beyond acceptable limits set by applicable reliability standards. Such operation can impact performance and efficiency of end-user equipment, particularly of industrial customers (e.g., motors), and cause disruptions and equipment damage

- **Short-circuit duty increase:** Distribution systems must be de-energized when a fault occurs (e.g., when a tree branch falls over an overhead line) to protect the public from potential safety hazards and to prevent further equipment damage. This de-energization operation is carried out by switchgear equipment (e.g., circuit breakers and reclosers), which need to be designed and rated to withstand the high currents observed during fault conditions (commonly known as fault currents or short-circuit currents). In traditional distribution systems with no DG, fault currents are supplied only by the centralized generation system through transmission lines and distribution substations. Therefore, most distribution system equipment has been designed and rated for this type of traditional application. In contrast, in distribution systems with DG each DG unit becomes an additional source of fault current, meaning the aggregated fault current contribution from all DG units (plus that of the centralized

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17 Power factor of 1.0, obtained when current and voltage are in phase, as in a circuit containing only resistance or in a reactive circuit at resonance. McGraw-Hill Dictionary of Scientific & Technical Terms, 6E. "unity power factor." Accessed February 6, 2017.

generation system) may exceed the original design ratings of the switchgear, damage the equipment, and create additional fault and hazard conditions.

- **Overcurrent and overvoltage protection issues:** Overcurrent and overvoltage protection equipment and practices are necessary to prevent or minimize potential damage to distribution and customer equipment (e.g., appliances) due to distribution system faults and voltage surges. However, the large majority of these practices have been designed for unidirectional distribution feeders and may not be fully applicable to feeders with DG, which have bi-directional power flows. Potential resulting problems may include temporary overvoltages (surges) caused by islanding (i.e., disconnection) of sections of the distribution system with large enough penetration of DG, and misoperation of protection systems (e.g., sympathetic tripping and reach modification).

- **Power quality issues:** Voltage fluctuations caused by variable DG may be severe and frequent enough to create visible variations in lighting systems, which are known as flicker. Furthermore, high penetration levels of inverter-based DG, may increase total harmonic distortion (THD), which measures the quality of the voltage supply. If flicker or THD exceed acceptable limits, they can create unacceptable visual discomfort for end-users, or disrupt operation of the distribution system (e.g., increase system losses, lead to capacitor bank resonance, transformer and motor overheating and failure) and affect sensitive loads (e.g., misoperation of microprocessor-based equipment and motor drives),respectively.[18]

Illustrative Case Study on DG Integration Costs in Distribution Grids:

As discussed in previous sections, DG integration is a very complex endeavor that is a function of several variables, including the electric characteristics (e.g., voltage level, capacity of feeders, customer and load density, etc.) and hosting capacity of the distribution grid and the expected penetration levels of the specific DG technology of interest. Energy companies already experiencing high penetration levels of DG, such as the California IOUs and Hawaiian Electric, have initiated the process of teasing out the expected costs and benefits of DG integration as evidenced by California's Distribution Resources Plan (DRP) and Hawaii's Distributed Generation Interconnection Plan (DGIP).

18 Sankaran, C., Electrical Construction and Maintenance, "Effects of Harmonics on Power Systems", (October 1, 1999).

Hawaii's DGIP includes cost estimates of mitigation measures required to integrate expected DG penetration levels in Hawaii. Mitigation measures to reinforce the distribution grid include deploying voltage regulation/control equipment with the ability to operate under bidirectional power flow conditions, upgrading line conductors (reconductoring), transformers and switchgear, replacing poles and secondary (low voltage) lines, and deploying special equipment to mitigate potential high voltage violations (grounding transformers). These costs, summarized in Figure 3, show, for instance, that the integration of about 900 MW of DG is expected to require an investment of approximately $138M, or about 0.15 $/W.

Figure 3 - Distribution Circuit Improvement Implementation Plan[19]

Item	Violation Trigger	Unit Cost	2016	2020	2030	Total
Installed DG (MW, all three Companies)	--	--	547	677	902	
Regulator	Feeder Reverse Flow	$10,000	$187,000	$55,000	$66,000	$308,000
LTC	Substation Transformer Reverse Flow	$10,000	$912,000	$264,000	$466,000	$1,642,000
Reconductoring	Exceed 50% Backbone Conductor/Cable Capacity	$1,100,000 OH/ $4,300,000 UG per mile	$-	$-	$75,588,700	$75,588,700
Substation Transformer and Switchgear	Exceed 50% Capacity	Varies	$2,541,000	$2,475,000	$49,750,000	$54,766,000
Distribution Transformer	Exceed 100% Loading, % GDML Linear Relationship to % Transformers Upgraded	Varies	$4,462,164	$4,386,633	$6,768,738	$15,617,535
Poles and Secondary	Assumed 15% of Distribution Transformer Replacements Include Pole Replacement and Secondary Upgrades	Varies	$1,016,605	$993,371	$1,523,365	$3,533,342
Grounding Transformers	Exceed 33% GDML (66% in model) for Selected Feeder for Maui Electric and Hawai'i Electric Light; exceed 50% GDML for 46 kV Lines for Hawaiian Electric	$60,000 for Maui Electric Company and Hawai'i Electric Light; $947,000 for Hawaiian Electric	$33,033,000	$6,095,100	$3,917,100	$43,045,200
Total	--	--	$42,151,769	$14,269,104	$138,079,904	$194,500,777

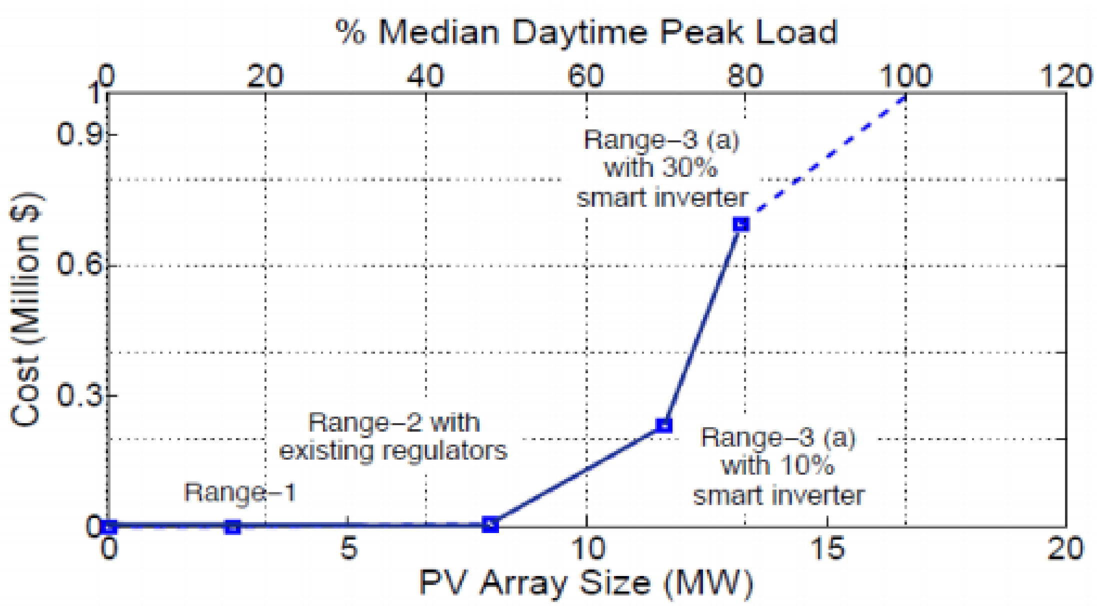
It is worth noting that integration costs increase as DG penetration grows and gets closer to the hosting capacity of the grid. Figure 4 depicts this correlation, charting DG integration costs for various DG penetration scenarios for a feeder with a hosting capacity of about 17 MW. The mitigation measures used in this case comprise conventional solutions such as voltage regulators, and advanced technologies such as smart inverters. Smart inverters (also known as advanced inverters) control voltage increase and voltage fluctuations caused by DG output variability in a more efficient manner than voltage regulators, making them more suitable for high penetration levels of DG.

The results of this analysis show that the costs of mitigation measures for DG integration vary from inexpensive operational changes or equipment upgrades

19 Submission of Hawaii Electric Companies to the Hawaii Public Utilities, Commission, "Distributed Generation Interconnection Plan", (August 26, 2014).

to increase hosting capacity to more expensive upgrades such as replacing existing conventional inverters with smart inverters. For instance, replacing 30% of existing inverters in this feeder (i.e., to integrate approximately 13 MW of DG) would require an investment of $700k, or about 0.05 $/W. It is important to remember that these costs are not linear and are a function of the specific electric characteristics of each feeder and distribution system. Therefore, they need to be determined via simulations specific to a particular distribution system using computational models and should not be generalized.

Figure 4 – Costs of PV Integration on Distribution Feeder[20]



2. Use Case: Distributed Energy Storage (DES):

This case discusses the application of DES for the integration of solar PV in distribution systems, as well as some of the technical and economic considerations regarding the combined utilization of DES (e.g., behind-the-meter battery storage systems) and rooftop PV for residential applications, including intentional islanding.

DES is increasingly becoming an alternative to mitigate the impacts associated with distribution-level residential and utility-scale PV interconnection. Figure 5 shows this type of application for a distribution feeder with a PV plant: the plant has a variable output that may impact feeder operation, and so the DES is used to compensate for output variations as needed. For instance, the DES may

20 The University of Texas at Austin, Energy Institute, "Integrating Photovoltaic Generation", (May 2016).

inject (or absorb) power when the PV output is smaller (or greater) than a predefined threshold. This way the combined output from the plant and DES remains relatively "smooth," and the feeder demand only exhibits small, controllable, and predictable variations.

Figure 5: DES Facilitates Interconnection of DG

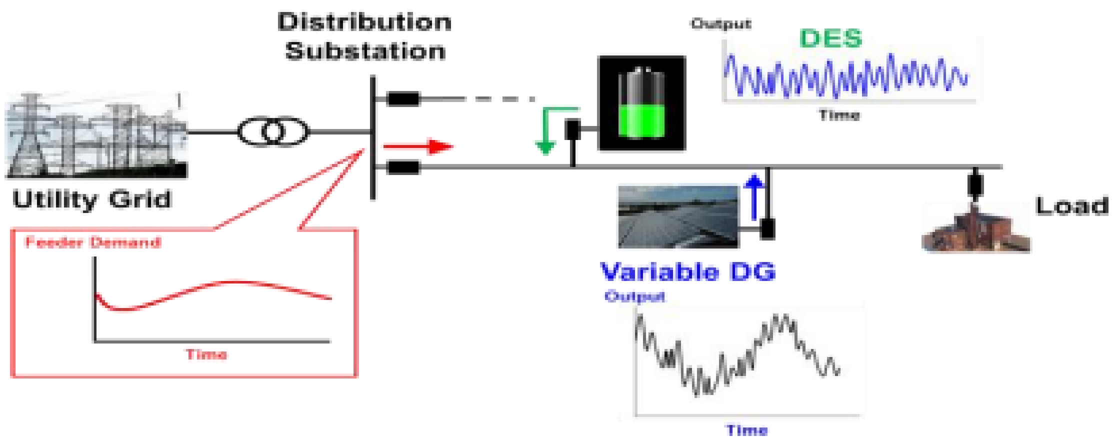


Figure 5 - Application of utility-scale DES for integration of PV DG. The combined output from the PV plant and DES facility is relatively controllable, predictable, and exhibits relatively small variations.

In this case, the DES facilitates integration by preventing potential power flow and voltage fluctuations and interactions with voltage regulation and control equipment that otherwise could be caused by the PV plant. This is illustrated in Figure 6, which shows voltage at the point of interconnection of a PV plant before and after implementation of a DES solution. Voltage after DES application exhibits slower variations (i.e., the rate of change of voltage is smaller) than the base case (i.e., before DES application) that can be mitigated by voltage regulation equipment.

Figure 6: DES Stabilizes Variations in DG Voltage

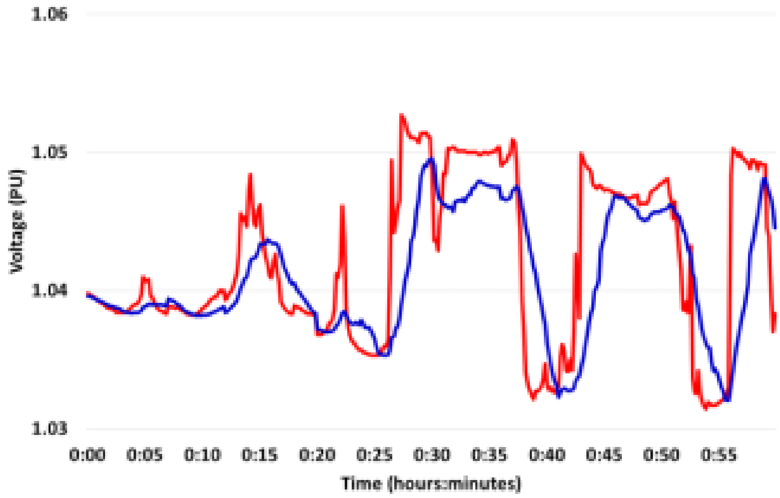


Figure 6 – Application of utility-scale DES for mitigation of voltage fluctuations caused by PV output variability. Plot shows voltage at the point of interconnection of a PV plant before (red) and after (blue) implementation of DES solution.

The controllability of the combined output from DES and PV plants can also be used for "peak shaving" to relieve overloads and effectively defer capital investments needed to increase installed capacity. This type of application is shown in Figure 7:

Figure 7: DES as a Peak Shaving Strategy

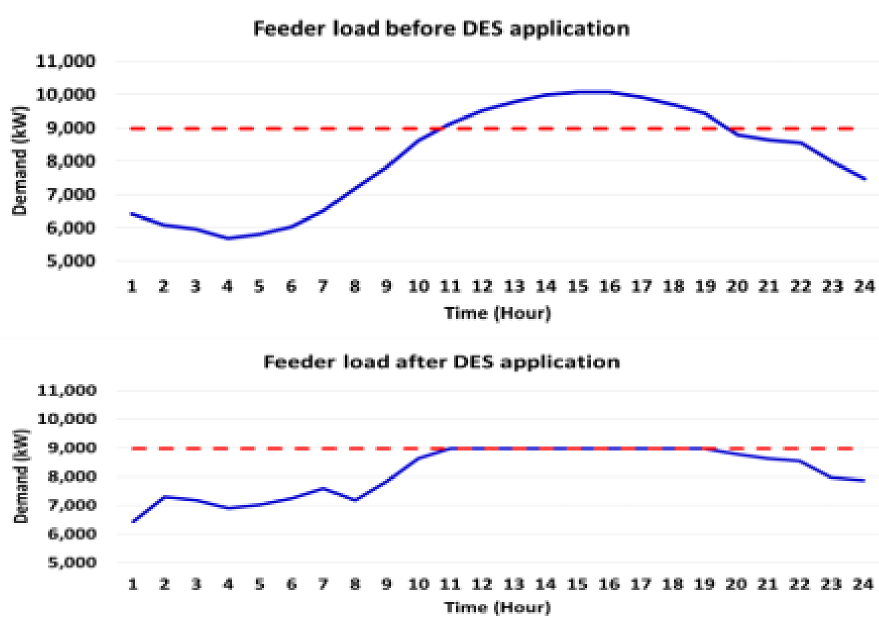


Figure 7 – Application of utility-scale DES for deferral of capital investments needed to increase capacity. Plot shows feeder demand before (above) and after (below) implementing DES. The dotted red line is the maximum available capacity of the feeder. The combined DES and PV plant application is used to supply part of load locally and reduce the demand that needs to be supplied by the feeder, which effectively defers the need to increase capacity.

The aforementioned applications can be implemented not only at the distribution substation and feeder level, but also at the service transformer and household level, as conceptually shown in Figure 8.

Figure 8: DES at the Residential Level

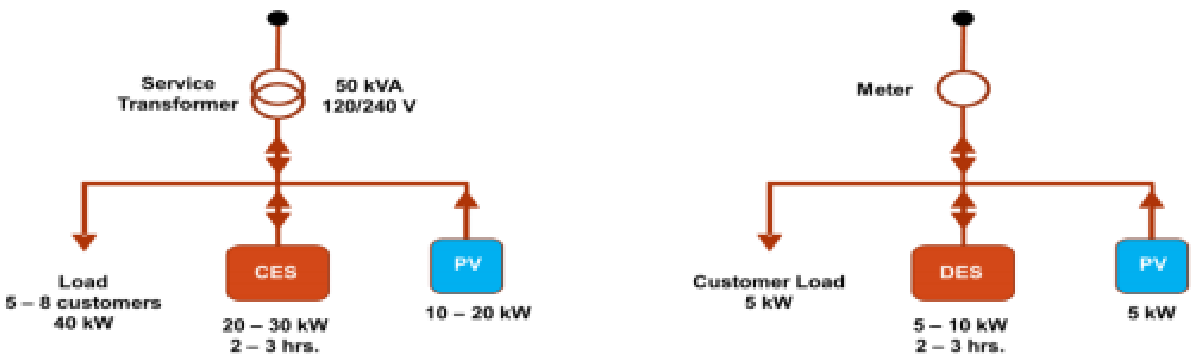


Figure 8 – Application of Community Energy Storage (CES) and rooftop PV at service transformer level (left) and application of behindthe-meter DES and rooftop PV at customer level (right).

In the specific case of customer applications of DES and rooftop PV for intentional islanding, it is important to highlight that this solution requires the utilization of grid-forming “voltage source” inverters, which can control voltage and frequency (within predefined) limits in a similar fashion as a conventional generator. However, most inverters used in residential rooftop PV applications are “current source” inverters, which require a steady voltage signal – provided by the grid during normal operation – to interconnect and inject power to the grid. Although DES may be able to fill this role, the variability of PV output due to daily and seasonal radiation patterns, as well as sudden solar radiation changes caused by clouding, would require large and expensive DES installations to be able to fully supply customer loads over the entire day. For this reason, this type of application is usually reserved for backup operation of critical loads (e.g., lighting) for a short period (e.g., 2 – 4 hrs.), rather than to fully supply large household loads, such as heating, ventilation and air conditioning systems.

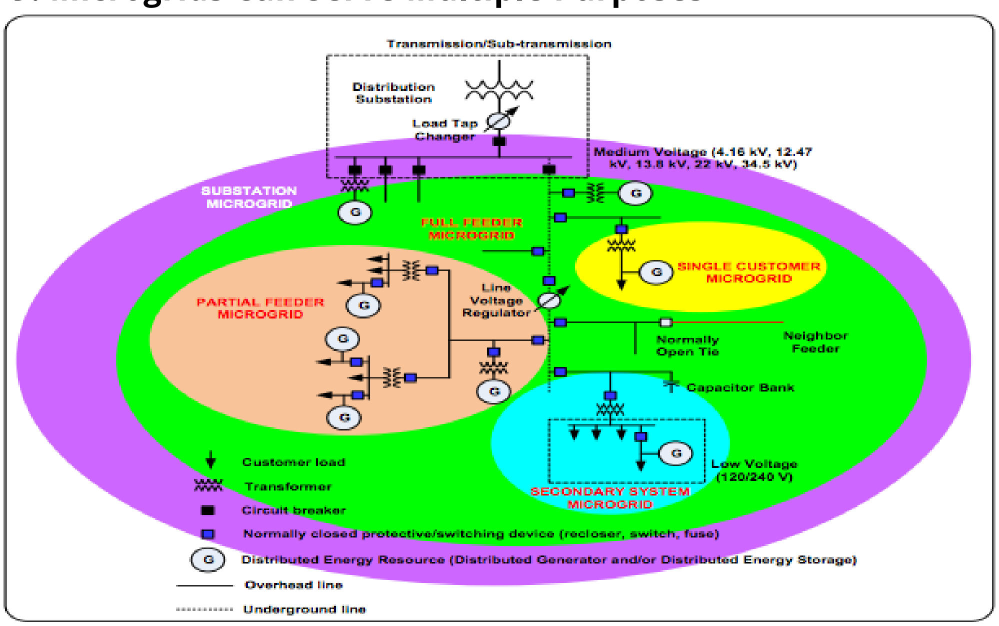
Technical limitations to customer grid defection (i.e., customer's going "off-grid") include the reliability and maintenance requirements of the combined PV and DES system. In an off-grid application, reliability issues and maintenance activities would likely require partial or full service interruptions. For instance, a fault on a PV system may lead to an extended outage since the DES may not have enough energy to provide service to all end-user loads while the PV system is repaired, and there would be no grid to serve as a backup. Similarly, a fault on the DES system, particularly if it occurs during nighttime, could lead to a long duration outage. For this reason, a more likely future scenario is the grid-connected utilization of DES and PV systems.[21]

Grid-connected DES and PV systems would offset customer demand, provide service during grid outages, and inject surplus production to the grid, while additional end-user consumption requirements would be supplied by the grid. Moreover, the combined utilization of these technologies at end-user levels would help minimize the impacts derived from variable PV output, and in this regard would promote reliability. It is worth noting that grid-connected utilization of PV systems is already a reality in numerous markets around the world, while DES is slowly but steadily emerging as a complementary solution.

3. Use Case: Microgrids

There is growing interest in the application of microgrids to improve system resiliency and efficiency. Examples of the various types of potential microgrid types are shown in Figure 9.

Figure 9: Microgrids Can Serve Multiple Purposes



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[21] The power grid started as a collection of small grids that were interconnected with the purpose of improving reliability and sharing generation resources to improve overall efficiency.

Figure 9 – Conceptual examples of microgrid configurations: single customer, secondary system, partial feeder, feeder, and substation microgrids.[22]

These configurations can provide service to a single customer, such as a campus microgrid, or to a group of customers, such as a secondary microgrid, partial and full feeder microgrids, and substation microgrids. One example of a community microgrid is San Diego Gas & Electric's (SDG&E) Borrego Springs microgrid, which has been successfully used to provide service to residential and commercial customers and prevent or reduce the duration of service interruptions caused by scheduled maintenance and faults, as shown in Figure 10.

Figure 10: SDG&E Examples of Microgrid Preventing Loss of Service

Figure 10 – Examples of resiliency improvement experiences derived from implementation of San Diego Gas & Electric's Borrego Springs microgrid. Source: SDG&E.[23]

Some of the key technical challenges associated with community microgrid implementations include the need to deploy widespread communications systems, as well as specialized real-time monitoring, protection, automation and control equipment, including a microgrid controller, which increases the cost of the overall deployment making it difficult to build a business case. The complexity of a microgrid implementation is illustrated in Figure 11, which shows a wide variety of DER and loads distributed over what could be a large feeder and substation footprint.

22 J. Romero Aguero, R. Masiello, A. Khodaei, The Utility and Grid of the Future, IEEE Power and Energy Magazine, Sep/Oct 2016 http://ieeexplore.ieee.org/document/7549242/.

23 J. Romero Aguero, Transforming DG, T&D World Magazine, Apr. 2016, http://tdworld.com/generationrenewables/transforming-dg.

Figure 11: Microgrid Configuration

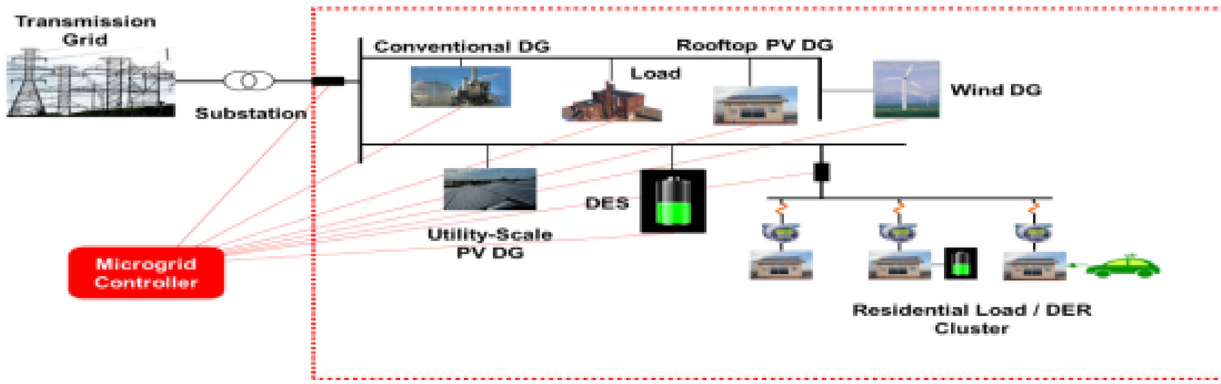

Figure 11 – Conceptual description of importance of distribution grid for implementation of community microgrids. The area within the dotted red square represents a microgrid footprint, and the solid red lines represent the high-speed communications link for real-time control of the microgrid DER and loads.

The control and coordinated dispatch of these resources requires high-speed communication infrastructure, such as optical fiber cable, and advanced and complex control system architectures to ensure generation and load balance and operation within voltage and frequency requirements during islanded operation. This can be accomplished by optimally dispatching DG and DES, and implementing DR and load control when needed, which may also require real-time modeling and simulation of the microgrid components and implementation of complex optimization, load, and DER output forecasting algorithms.

These technologies are generally not available at the distribution feeder and customer level, since historically they have not been used or required by utilities. Figure 11 also shows the importance of the distribution grid as the platform and enabler for integration and dispatch of the DER in the microgrid. Regardless of the type of microgrid operation, both grid-connected and islanded operation of community microgrids rely on the utilization of the distribution grid to supply customer demands.

4. Use Case: Smart IT Hardware, Software, and Energy Analytics

The deployment of smart IT hardware and software and the use of energy analytics are key emerging areas needed to enhance the operational efficiency, resiliency, and reliability of the grid, improve the quality of service provided to end-users, and meet evolving customer expectations.

Figure 12 shows an example of energy analytics utilization to analyze the feasibility of implementing Volt-VAR Optimization (VVO) in distribution systems. The purpose of VVO is to identify optimal settings of voltage regulation and control equipment typically used in distribution systems, such as load tap changers, line voltage regulators, and capacitor banks, for a wide variety of operating conditions to meet predefined objectives, such as to reduce delivered energy (energy efficiency) and peak demand (deferral of capital investments for capacity increase). The plots show voltage profiles of a feeder before (left) and after (right) implementing VVO. The results show the expected range of feeder voltages for all the expected annual loading conditions for base and VVO cases.

Figure 12: Energy Analytics Drive Voltage Reduction

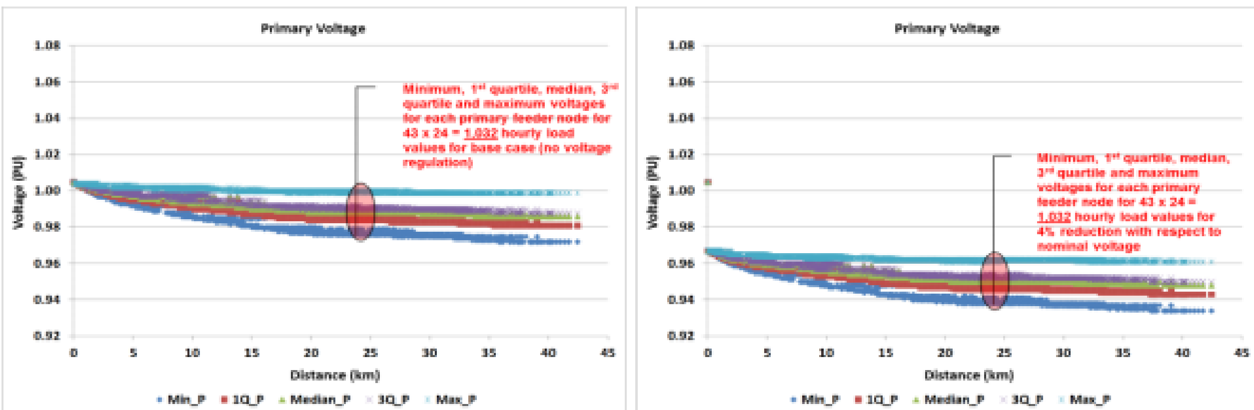

Figure 12 – Application of Conservation Voltage Reduction (CVR) using big data analytics, and time-series modeling and simulation[24]. Source: CENTROSUR

The analysis depicted in Figure 12 used a predictive analytics approach. The 1,032 hourly loading conditions used in this analysis were designed to represent typical feeder load profiles for every weekday and weekend of each month, plus selected holidays, to accurately reflect consumer consumption patterns. The input data was obtained from utility information systems and the feeder computational model included all key components for this type of analysis, such as service transformers. Using complex energy analytics and big data for this simulation (and others like it) allows utilities to more accurately perform cost/benefit analyses and build business cases to justify implementation of proposed efficiency improvements. To assess the solutions proposed requires the ability to collect data in the field via smart meters and sensors, transmit it to control centers and information system databases via suitable communications infrastructure (e.g., optic fiber cable), and process it

[24] The voltage profiles shown in Figure 12 are described via statistical parameters calculated for each feeder node via computational modeling and time-series power flow analyses of 1,032 hourly feeder load conditions. The voltage analysis consisted of calculating the minimum, first quartile, median, third quartile, and maximum voltage values for each node before and after implementing VVO, along with the respective delivered energy, power and energy losses, and annual peak demand.

via data analytics solutions. This type of automated analysis requires investments in electric and communications infrastructure (e.g., deploying smart meters and optic fiber cable), and information systems (e.g., data warehouses, big data applications, software, workstations, etc.).

5. Use Case: Plug-in Electric Vehicles (PEVs)

This case examines how the potential utilization of load control (e.g., via implementation of financial incentives or penalties such as time-of-use rates) could be help mitigate potential distribution infrastructure challenges brought on by increased deployment of PEVs. Distribution infrastructure, which was designed to supply existing peak loads, could be overloaded by the additional demand from PEV charging, particularly when they are clustered in a geographic area. This can also lead to service quality problems, efficiency issues, equipment damage, and, in worst case scenarios, service interruptions.

These challenges can be addressed via a combination of conventional and traditional solutions, such as infrastructure reinforcement, system reconfiguration, time-of-use rates, and load management systems. Two possible scenarios are shown in Figure 13, uncontrolled and controlled:

- Uncontrolled means there is nothing in place that requires or incentivizes the customer to charge at a time that is more beneficial in terms of minimizing the impact on system peak, transformer loading, voltage, etc. In short, charging will occur whenever the customer desires. Generally, an uncontrolled scenario will yield a higher number of overloaded transformers and circuits than a controlled scenario.
- Controlled charging means charging will occur when it best fits the system requirements. The controlled charging scenario shows the benefits of providing some control or incentive for when the charging can take place, thus minimizing overloads and voltage issues.

In the controlled scenario, the same amount of PEV charging load as in the uncontrolled case is added to the feeder, but the load is shifted both in terms of magnitude and duration in order to minimize overloads and voltage issues. The same amount of kilowatt-hours of charging occurs at each location as with the uncontrolled scenario but the charging is spread out and the load shape leveled over the off-peak time period.[25] Figure 13 shows the difference between uncontrolled and controlled charging on a distribution feeder with PEV loads.

[25] L. Dow, M. Marshall, L. Xu, J. Romero Agüero, L. Willis, A Novel Approach for Evaluating the Impact of Electric Vehicles on the Power Distribution System, 2010 IEEE PES General Meeting.

Figure 13: Comparison of PEV Charging Scenarios

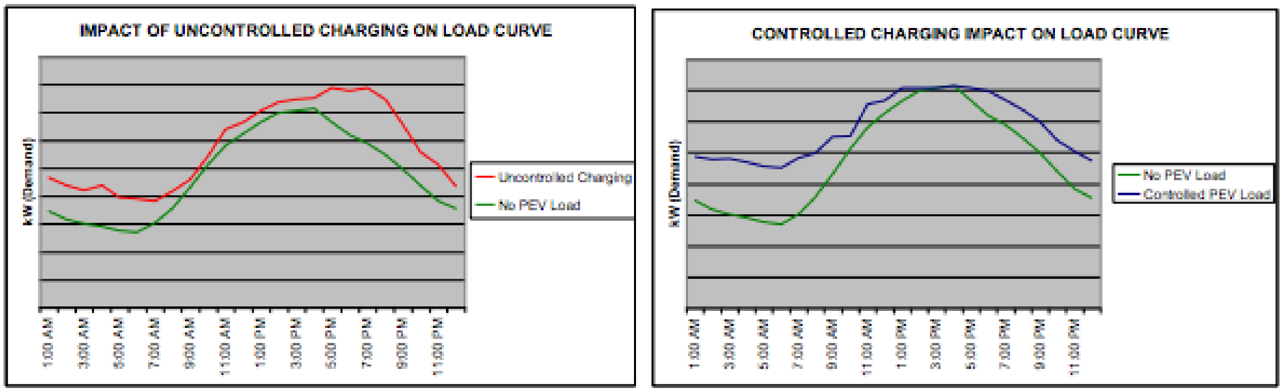

Figure 13 – Difference between uncontrolled and controlled PEV charging scenarios.[26]

Here, it was assumed that the controlled PEV charging time ranges from 5PM to 8AM of the next day. The total kilowatt-hours due to PEV charging during the 24-hour period is the same for the uncontrolled and controlled cases, but in the controlled scenario the PEV charging load is shifted to avoid increasing the peak load. In the uncontrolled scenario, the feeder peak load is increased with the added PEV load. In the controlled scenario, the PEV charging load is increased during some hours and decreased during others to ensure that the feeder peak load is not increased, while still providing the same amount of energy to charge the PEV batteries. This example suggests that some of the potential challenges associated with PEV integration can be mitigated if the grid operator exercises some control over how and when PEV are charged.

The implementation of this type of operation requires the deployment of sensors and control systems at the customer level that allow for two-way communication and control actions over loads of interest, which can include PEV chargers, HVAC systems, and appliances (e.g., washer/dryers). Furthermore, it requires having suitable communications systems in place to implement control actions, and utility controllers (residing for instance at service transformers, substations, or control centers) to process the collected data and make intelligent decisions that will then be communicated and implemented at customer level. Alternatively, control actions can be implemented locally, for instance, via energy price signals. In this type of application, a controller, (e.g., home automation system) located at customer level receives periodic information about electricity prices or other control signals provided by the utility and dispatches loads of interest accordingly to meet predefined objectives.

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[26] J. Romero Aguero, Tools for Success, IEEE Power and Energy Magazine (Sept./Oct. 2011).

Notably, there is also growing interest in the industry in the utilization of PEV in DER applications to inject power to the grid when needed. This emerging application is called Vehicle-to-Grid (V2G), and although it represents a potential additional benefit of PEV, there are challenges that need to be addressed before wide-scale implementation can be adopted, including technical and commercial issues, such as a better understanding of impacts on battery life-cycle and determining any respective liability implications for vehicle manufacturers and owners.

6. Use Case: Cybersecurity

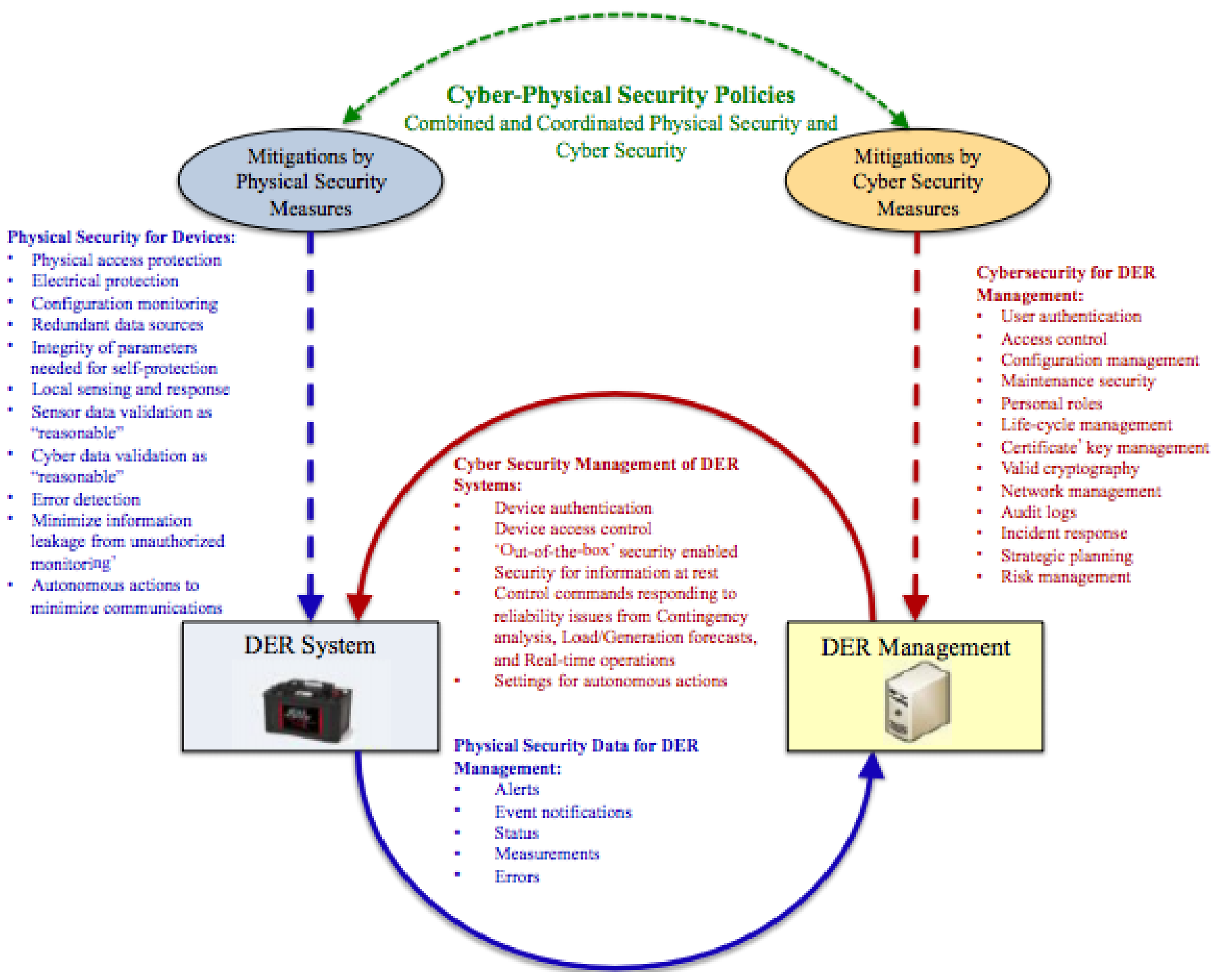
As distribution systems evolve into active and dynamic networks, energy companies and grid operators will continue integrating new technologies, including advanced sensors and controllers, distribution automation devices, smart meters and DER. The current trend is to integrate these technologies using common communications protocols and standards to ensure interoperability, enable real-time control and implementation of grid analytics functions. Unless suitable mitigation measures are implemented, each one of these components may represent a cybersecurity threat vector for utility systems because they will eventually be deeply connected with operations technology, information technology, and business intelligence and grid analytics systems.

The North American Electric Reliability Corporation (NERC) implemented the Critical Infrastructure Protection (CIP) standards as a defense mechanism against these threats. The CIP standards are intended to ensure physical and cybersecurity of generation and transmission systems. Notably, CIP standards do not cover distribution grids. Moreover, in some cases the demarcation line between a utility's transmission and distribution grid is blurred and somewhat difficult to define, especially when they share common information systems, e.g., Supervisory Control and Data Acquisition (SCADA). Finally, numerous municipal utilities and rural cooperatives only operate distribution grids, and consequently, are not overseen by NERC CIP standards, or share transmission facilities with other utilities.

Given that there is no all-embracing federal policy responsible for addressing cybersecurity for distribution grid components (including DER), states are taking the lead in defining cybersecurity policy and requirements. For instance, the New York Public Service Commission in its Distributed System Implementation Plan has discussed the need to strike a balance between enabling customer engagement and maintaining cybersecurity and privacy protection. Similarly, in their Distribution Resources Plans, California investor-owned utilities define the need for updated risk assessments, cybersecurity and privacy standards, and system designs. Finally, Texas has also mandated compliance with cybersecurity standards to maintain grid reliability. In order to address these needs, distribution utilities are starting to move to an enterprise risk-based cybersecurity group focused across operations and information technology and the introduction of corporate-level leadership responsible for overarching compliance.

Figure 14 shows an example of the cybersecurity mitigation measures needed for DER systems. Implementing these measures requires additional investments in information technology and additional work in standards and regulations to ensure compliance not only by utility distribution systems, but also of new products and emerging technologies.[27]

Figure 14: Mitigation by Physical and Cybersecurity Measures



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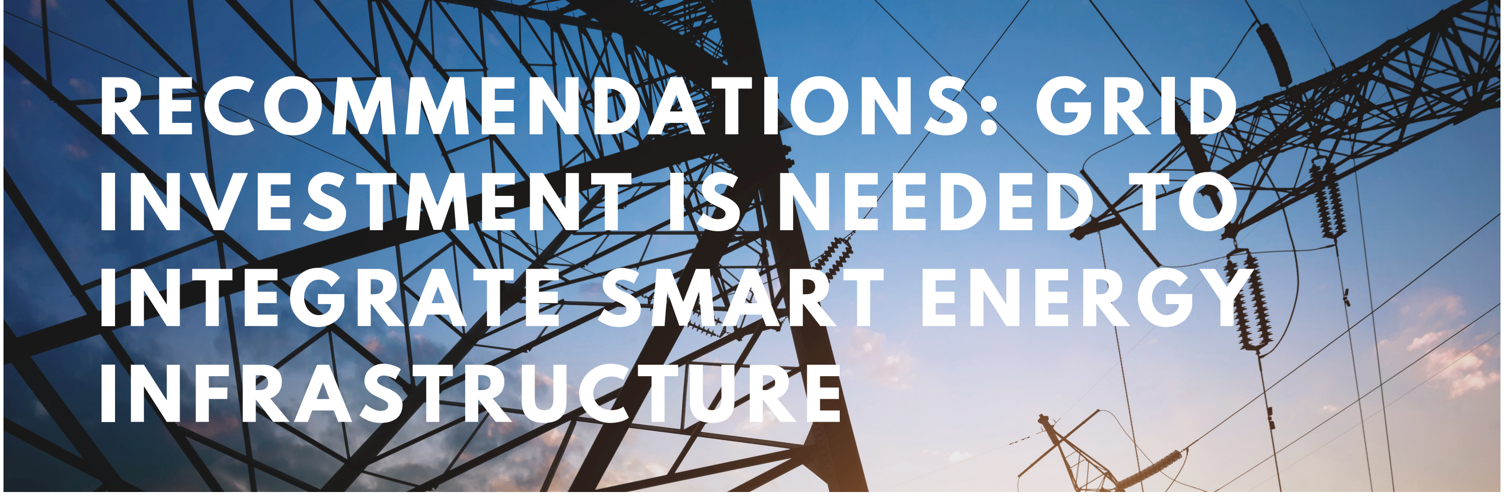
27 Xanthus Consulting, "Draft Distributed Energy Resources (DER) Cybersecurity Recommendations for DER System Stakeholders," April 28, 2013.

RECOMMENDATIONS: GRID INVESTMENT IS NEEDED TO INTEGRATE SMART ENERGY INFRASTRUCTURE



There are numerous benefits to be gained from the proper deployment of smart energy infrastructure, including DER, DES, microgrids, PEVs, and the other smart technologies discussed throughout this paper. These include maximizing emissions reductions, capacity deferral, efficiency improvement for optimal grid operation, and potential reliability and resiliency improvement. The grid itself is the backbone and platform that can facilitate the coordinated adoption of these emerging technologies and processes to achieve a cleaner, more modern, efficient, reliable and secure power system. However, to accomplish this transition, grid infrastructure needs to be properly modernized to safely and efficiently facilitate the flow and storage of the energy and information that makes the smart grid possible.

More specifically, integration of smart energy technologies, particularly DER, requires a modern, intelligent, and resilient grid. Although smart grid and grid modernization initiatives have helped enhance distribution system infrastructure, there is significant work ahead, including the replacement of aging and outdated assets and systems, and the deployment of new smart infrastructure, such as communications and information systems. Moreover, grid modernization needs to be accompanied by updated utility engineering, planning, and operations that enable the needed mechanisms to fully utilize emerging and advanced technologies, and allow society and industry in general to benefit from their integration.

In addition to modernization efforts already underway, state and federal policymakers, as well as electric sector stakeholders, should consider undertaking the following investments, modifications, and practices:

- **Enhanced foundational infrastructure:** Investments in overhead and underground lines with conductors and cable with sufficient capacity are necessary to facilitate the movement of power to and from forecasted increases of DER.

- **Advanced protection, distribution automation, and AMI:** Widespread variable DG adoption, particularly PV systems, is transforming distribution systems from passive grids to dynamic networks. This type of system requires increased visibility, observability, awareness, and management in real-time. Needed investments include deployment of advanced reclosers, distribution automation switches, advanced sensors, modern voltage control/regulation devices, and AMI (i.e., smart meters).

- **Communications infrastructure:** Additional investment is needed to ensure data collected in the field can be sent to utility control centers, distributed controllers, and information systems, and control decisions communicated back to field devices in real-time. Current distribution systems either do not have two-way communications infrastructure with enough bandwidth and reliability to collect data and implement control actions, or their coverage is limited to distribution substations and a few critical components.

- **Advanced control/management systems and grid analytics:** Controlling an active and dynamic distribution grid requires advanced control and management systems and applications with advanced algorithms that can process the data collected in the field to make intelligent control decisions aimed at optimizing real-time distribution system performance, including Distribution Management Systems (DMS), Outage Management Systems (OMS), Distributed Energy Resources Management Systems (DERMS), and more.

- **Distributed Energy Storage:** Increased deployment of DES will help manage the reliability challenges that arise when integrating increased amounts of variable DG into distribution grids.

These investments and modifications will enable further adoption of customer or utility-owned DER without sacrificing safety or reliability. For example, without an adequate DER readiness strategy and a distribution grid with the capability to seamlessly integrate DER, it would not be possible for residential rooftop PV owners to interconnect their systems and be compensated for delivering excess power to the utility grid, or for PEV owners to use their vehicles as an energy asset instead of a peak load consumption liability. In this regard, the grid represents a vital enabler and platform for further adoption of DER and other technologies. But it's equally true that without grid reinforcements and new electric, communications and IT infrastructures in place, DER adoption will face hurdles and present challenges; challenges that can be overcome with proactive planning and investment.

While government and quasi-governmental organizations play a role in approving needed investments, the private sector will ultimately be responsible for planning and funding grid modernization projects throughout the U.S. Utilities are seemingly uniquely positioned to facilitate these activities, either directly or through partnerships with vendors, customers, and industry organizations, based on decades of experience and expertise, but also from an economies of scale perspective. Current energy companies are particularly well-suited to maintain a reliable, secure, safe and sustainable electric service, while introducing and implementing a diverse portfolio of new related services. They are also well positioned to develop and provide customized solutions based on customer feedback about their needs and expectations.

About Aii

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