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MODERN DISTRIBUTION GRID

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DISCLAIMER

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GLOSSARY

A glossary is provided below for industry and technology terms as referenced in the U.S. DOE DSPx effort.[1]

INDUSTRY DEFINITIONS

Balancing Authority (BA) is the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within an electrically-defined Balancing Authority Area (BAA), and supports interconnection frequency in real time. A utility TSO or an ISO/RTO may be a balancing authority for an area.

Distributed Energy Resources (DERs) include distributed generation resources, distributed energy storage, demand response, energy efficiency and electric vehicles that are connected to the electric distribution power grid.

Distribution System is the portion of the electric system that is composed of medium voltage (69 kV to 4 kV) sub-transmission lines, substations, feeders, and related equipment that transport the electricity commodity to and from customer homes and businesses and that link customers to the high-voltage transmission system. The distribution system includes all the components of the cyber-physical distribution grid as represented by the information, telecommunication and operational technologies needed to support reliable operation (collectively the "cyber" component) integrated with the physical infrastructure comprised of transformers, wires, switches and other apparatus (the "physical" component).

Distribution Grids today are largely radial, with sectionalizing and tie switches to enable shifting portions of one circuit to another for maintenance and outage restoration. Some cities have "network" type distribution systems with multiple feeders linked together to provide higher reliability.

Distribution Utility or Distribution Owner (DO) is a state-regulated private entity, locally regulated municipal entity, or cooperative that owns an electric distribution grid in a defined franchise service area, typically responsible under state or federal law for the safe and reliable operation of its system. In the case of a vertically integrated utility, the distribution function would be a component of the utility. This definition excludes the other functions that an electric utility may perform. This is done to concentrate on the distribution wires service without confounding it with other functions such as retail electricity commodity sales, ownership of generation, or other products or services, which a vertically integrated utility may also provide.

Integrated Grid is an electric grid with interconnected DERs that are actively integrated into distribution and bulk power system planning and operations to realize net customer and societal benefits.

Independent System Operator (ISO) or Regional Transmission Organization (RTO) is an independent, federally regulated entity that is a Transmission System Operator (TSO), a wholesale market operator, a Balancing Authority (BA) and a Planning Authority.

Internet of Things (IOT) is the network of physical objects (or "things") embedded with electronics, software, sensors, and connectivity that enables the object to achieve greater value and service by exchanging data with operators, aggregators and/or other connected devices. Each object has a unique identifier in its embedded computing system but can interoperate within the existing Internet infrastructure.[2]

Local Distribution Area (LDA) consists of all the distribution facilities and connected DERs and customers below a single transmission-distribution (T-D) interface on the transmission grid. Each LDA is not normally electrically connected to the facilities below another T-D interface except through the transmission grid. However, to improve reliability, open ties between substations at the distribution level exist.

Markets as referred to generically in this report include any of three types of energy markets: wholesale power supply (including demand response), distribution services, and retail customer energy services. Markets for sourcing non-wires alternatives for distribution may employ one of three general structures: prices (e.g., spot market prices based on bid-based auctions, or tariffs with time-differentiated prices including dynamic prices); programs (e.g., for energy efficiency and demand response) or procurements (e.g., request for proposals/offers, bilateral contracts such as power purchase agreements).

Microgrid is a group of interconnected loads and DERs 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 modes.

Net Load is the load measured at a point on the electric system resulting from gross energy consumption and production (i.e., energy generation and storage discharge). Net load is often measured at a T-D interface and at customer connections.

Regulator is the entity responsible for oversight of the essential functions of the electric utility, including funding authorizations for power procurements, investments and operational expenses. This oversight extends to rate design, planning, scope of services and competitive market interaction. Throughout this report we use the term regulator in the most general sense to include state public utility commissions, governing boards for publicly owned utilities and rural electric cooperatives, and the Federal Energy Regulatory Commission (FERC).

Reliability Metrics[3] are used to assess the operational performance of the distribution system in terms of reliability and resilience. Some of the more commonly used metrics are:

- SAIDI (System Average Interruption Duration Index) – the total duration of interruptions for the average customer during a given time period. SAIDI is normally calculated on either monthly or yearly basis; however, it can also be calculated daily, or for any other time period.
- SAIFI (System Average Interruption Frequency Index) – the average number of outages a customer experienced during a year.
- CAIDI (Customer Average Interruption Duration Index) – if a customer experienced an outage during the year, the average length of time the customer was out of power, in hours.
- MAIFI (Momentary Average Interruption Frequency Index) – the average number of outages a customer experienced during the year that are restored within five minutes.

Scheduling Coordinator/Entity is a certified entity that schedules wholesale energy and transmission services on behalf of an eligible customer, load-serving entity, generator, aggregator or other wholesale market participant. This role is necessary to provide coordination between energy suppliers, load-serving entities and the transmission and wholesale market systems. This entity may also be a wholesale market participant.

Structures is an architectural structure created by configuration of functional partition in relation to actors, institutions and/or components and their relationships. Related structures include industry, market, operations, electric system, control, coordination and communications.

Transactive Energy is defined by techniques for managing the generation, consumption or flow of electric power within an electric power system through the use of economic or market-based constructs while considering grid reliability constraints. Transactive energy refers to the use of a combination of economic and control techniques to manage grid reliability and efficiency.[4]

Transmission-Distribution interface (T-D interface) is the physical point at which the transmission system and distribution system interconnect. This point is often the demarcation between federal and state regulatory jurisdiction. It is also a reference point for electric system planning, scheduling of power and, in ISO and RTO markets, the reference point for determining Locational Marginal Prices (LMP) of wholesale energy.

Transmission System Operator (TSO) is an entity responsible for the safe and reliable operation of a transmission system. For example, a TSO may be an ISO or RTO or a functional division within a vertically integrated utility, or a federal entity such as the Bonneville Power Administration or Tennessee Valley Authority.

Var is the standard abbreviation for Volt-Ampere-reactive, written "var,"[5] which results when electric power is delivered to an inductive load such as a motor.[6]

TECHNOLOGY DEFINITIONS

Advanced Distribution Management Systems (ADMS) are software platforms that integrate numerous operational systems, provide automated outage restoration, and optimize distribution grid performance. ADMS components and functions can include distribution management system (DMS); demand response management system (DRMS); automated fault location, isolation, and service restoration (FLISR); conservation voltage reduction (CVR); and Volt-var optimization (VVO).[7]

Advanced Metering Infrastructure (AMI) typically refers to the full measurement and collection system that includes meters at the customer site, communication networks between the customer and a service provider, such as an electric, gas, or water utility, and data reception and management systems that make the information available to the service provider.[8] It is also referred to as a smart meter system. AMI communications networks may also provide connectivity to other types of end devices such as distributed energy resources (DER).

Customer Information System (CIS) is the repository of customer data required for billing and collection purposes. CIS is used to produce bills from rate or pricing information and usage determinants from meter data collection systems and/or manual processes.[9]

Customer Relationship Management (CRM) is a system that provides tools for documenting and tracking all customer interactions. CRM also provides analytical tools to track and adjust marketing campaigns, forecast participation rates, and move customers from potential participants to fully engaged customers.[10]

Conservation Voltage Reduction (CVR) is an operating strategy of the equipment and control system used for VVO that reduces energy and peak demand by managing voltage at the lower part of the required range.[11]

Demand Response Management System (DRMS) is a software solution used to administer and operationalize DR aggregations and programs. Building on a legacy of telephone calls requesting load reduction, DRMS uses a one-way or two-way communication link to effect control over and gather information from enrolled systems, including some commercial and industrial loads, and residential devices such as pool pumps, air conditioners and water heaters.[12] DRMS allows DR capacity to be scaled in a cost-effective manner by automating the manual events that are typically used to execute DR events, as well as most aspects of settlement.

Distribution Management System (DMS) is an operational system capable of collecting, organizing, displaying, and analyzing real-time or near real-time electric distribution system information. A DMS can also allow operators to plan and execute complex distribution system operations to increase system efficiency, optimize power flows, and prevent overloads. A DMS can interface with other operations applications, such as geographic information systems (GIS), outage management systems (OMS), and CIS to create an integrated view of distribution operations.[13]

Distributed Energy Resource Management System (DERMS) is a software-based solution that increases an operator's real-time visibility into the status of DER, and allows for the heightened level of control and flexibility necessary to optimize DER and distribution grid operation.[14] A DERMS can also be used to monitor and control DER aggregations, forecast DER capability, and communicate with other enterprise systems and DER aggregators.[15]

Distribution SCADA (DSCADA) is the application of supervisory control and data acquisition software to the distribution grid. SCADA is defined below.

Energy Management System (EMS) is a system to monitor, control, and optimize the performance of the transmission system and in some cases primary distribution substations.[16] The EMS is the transmission system's analog to the DMS.

Fault Location, Isolation and Service Restoration (FLISR) includes the automatic sectionalizing, restoration and reconfiguration of circuits. These applications accomplish distribution automation operations by coordinating operation of field devices, software, and dedicated communications networks to automatically determine the location of a fault, and rapidly reconfigure the flow of electricity so that some or all customers can avoid experiencing outages.[17] FLISR may also be known as Fault Detection, Isolation and Restoration (FDIR).

Geographic Information System (GIS) is a software system that maintains a database of grid assets, including transmission and distribution equipment, and their geographic locations to enable presentation of the electric power system or portions of it on a map.[18] GIS may also serve as the system of record for electrical connectivity of the assets.

Global Positioning System (GPS) is a system of satellites and receivers that determines the position (latitude, longitude and altitude) of a receiver on Earth.[19] GPS is also used as a source of precision time signals for device synchronization.

Internet Protocol (IP) Packet Communication uses IP digital protocol to handle data in variable length packets that are routed digitally to their destinations asynchronously rather than making a fixed circuit connection or relying on fixed time intervals.[20]

Land Mobile Radio System (LMRS) is a central radio communication system that provides voice and data communications to a variety of endpoints including push-to-talk, walkie-talkies, and data modems for digital devices. They operate on licensed radio frequencies.[21]

Microgrid Interface is the set of power electronics at the Point Of Interconnection (POI)[22] between the "island-able" portions of a grid, and the larger distribution grid, that support the essential microgrid[23] functions of islanding and reconnection.[24] The microgrid interface may also have the capability to provide services to the macro grid including Volt-var control.[25] As services are dropped from the distribution grid side of the interconnection, the microgrid interconnect disconnects, and the microgrid continues to provide service to critical loads in the islanded area.

Microwave Radio communications are high frequency radio systems that may be point-to-point or point-to-multipoint systems. They are widely used for substation and SCADA communications.[26]

Optical Fiber communication systems send data via modulated light through a transparent glass or plastic fiber. Optical fiber systems are capable of very high bandwidths and form the backbone of high capacity communication systems.[27]

Outage Management System (OMS) is a computer-aided system used to better manage the response to power outages or other planned or unplanned power quality events.[28] It can serve as the system of record for the as-operated distribution connectivity model, as can the DMS.

Peer-to-Peer Communication (P2P) may be a network service or standalone capability that permits two devices to communicate with one another. As a network service, the central part of the system responds to a request by providing each device the information and resource necessary to establish direct communication. As a standalone capability, P2P becomes synonymous with point-to-point and is a dedicated channel between devices.[29]

Reclosers are electro-mechanical devices that can react to a short circuit by interrupting electrical flow and automatically reconnecting it a short time later. Reclosers function as circuit breakers on the feeder circuit and are located throughout the distribution system to prevent a temporary fault from causing an outage.[30]

Satellite Radio Frequency Communications is one of the services provided by the more than 2,000 communication satellites in orbit around the Earth. Satellites have the advantage of unobstructed coverage requiring only a suitable ground station. Satellite radio is used in remote locations where the construction of radio towers or other land-based infrastructure is cost-prohibitive.[31]

Supervisory Control and Data Acquisition (SCADA) is a system of remote control and telemetry used to monitor and control the transmission system.[32]

Time Division Multiplex Communication (TDM) is a method of transmitting and receiving independent signals over a common signal path by means of synchronized switches at each end of the transmission line so that each signal appears on the line for a fraction of time in an alternating pattern. This form of signal multiplexing was developed in telecommunications for telegraphy systems in the late 19th century, but found its most common application in digital telephony in the second half of the 20th century.[33]

Worldwide Interoperability for Microwave Access (WiMAX) is a standards-based radio technology enabling the delivery of wireless broadband access to system end points.[34]

Wireline Communication is communication using twisted pair or coaxial cable as the transport medium. Some usages of "wireline" include optical fiber to distinguish from wireless (radio) communication. Use of the physical wire, coax, or fiber in communications can be any of a wide range of technologies including analog, digital, TDM, or IP technologies. [35]

1 INTRODUCTION

1.1 PURPOSE

The U.S. Department of Energy is working with state regulators, the utility industry, energy services companies and technology developers to determine the functional requirements for a modern distribution grid that are needed to enhance reliability, resiliency and operational efficiency, and integrate and utilize distributed energy resources (DER). DER as used in this report includes distributed generation, distributed energy storage, energy efficiency, demand response and electric vehicles.

The *Modern Distribution Grid Report* is a three-volume set that is intended to develop a consistent understanding of requirements to inform investments in grid modernization. The requirements include those needed to support grid planning, operations and markets. Volume I, "Customer and State Driven Functionality" provides a taxonomy of functional requirements derived from state policy objectives, and includes a discussion of grid architecture. Volume II, "Advanced Technology Maturity Assessment," examines the maturity of technology needed to enable the functions presented in Volume I. Volume III is a "Decision Guide" that presents considerations for the rational implementation of advanced distribution system functionality.

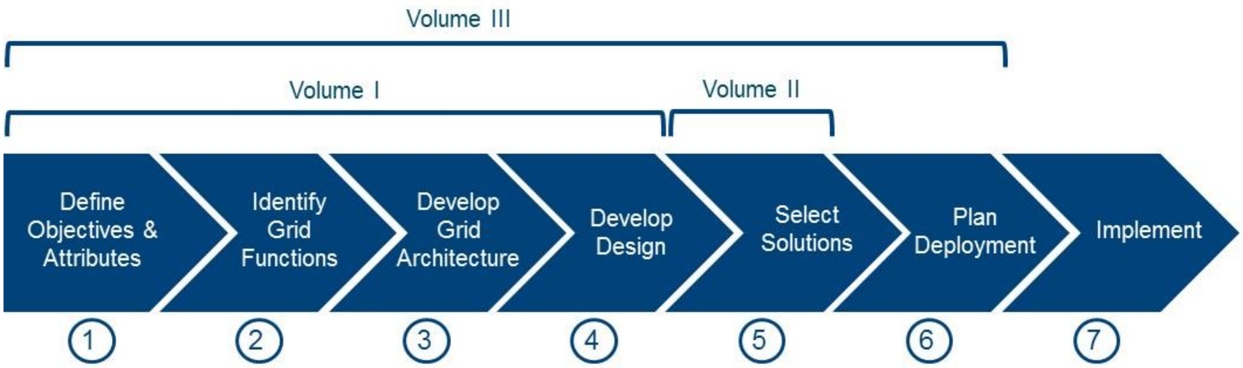
The intended audience of this Decision Guide are those interested in the strategic considerations and planning of grid modernization efforts related to any or all of the following: a) reliability, resiliency, safety and operational efficiency; b) enabling customer adoption of DERs; and c) the utilization of DERs as non-wires alternatives.[36] Development of the Decision Guide is the result of direct input from the sponsoring Public Service Commissions/Public Utilities Commissions and industry experts. The focus of this Guide is on the key considerations and questions raised by Commission staff and industry participants. As in the first two volumes of the series, Volume III was developed under these key assumptions of the DSPx initiative:

- **Five-year implementation time horizon**: This initiative focuses on the initial set of functions and related technologies needed to begin implementation within five years to support the sponsoring commissions' objectives.
- **Technology neutrality**: This initiative avoids preference of one type of technology over another, taking a technology neutral approach. This effort is also not focused on design-level solutions.
- **Broad applicability:** The initiative is meant to address grid modernization regardless of utility or market structure as it provides considerations for any regulator, utility and others contemplating modern grid investment. Given the focus on distribution grid investment, there may be aspects of this report that imply certain utility functions.

1.2 APPROACH AND ORGANIZATION

Modern Distribution Grid Volumes I-III combine to describe an overall decision process and related considerations that follow a classic stage-gate approach.[37] Figure 1 below shows this seven-step process that is described in the three Modern Distribution Grid volumes.

Figure 1: Modern Grid Decision Process



Volume I described Steps 1, 2, 3 and 4 as well as their interdependencies and identified best practices. Volume II identified the related modern grid technologies to be included in Step 5 and related considerations regarding adoption maturity. Volume III summarizes Steps 1-4, drawing on Volumes I and II and addresses considerations related to Steps 5 and 6. In Volume III, Step 5 is also expanded beyond the specific technologies to also consider "Who" may be able to provide the solutions needed beyond utility capital investment, including other utility options such as software-as-a-service (SaaS) and non-utility options. Step 6 addresses the "When", "How" and "How Much" considerations. In this context, Volume III includes five chapters briefly outlined below:

Chapter 1 – Introduction: The purpose of the first chapter is to reintroduce the objectives of the DSPx initiative, provide an overview of Volumes I and II, and highlight the intent of Volume III.

Chapter 2 – Design Considerations: This chapter provides an overview of the evolutionary factors that influence modern grid design including key architectural principles, including the rationale and the relationships of the core platform components.

Chapter 3 – Implementation Considerations: This chapter focuses on factors regarding alignment with customer needs and policies, how to consider flexibility in deployment plans, the potential to use non-utility technologies and considerations regarding application of several cost-effectiveness methods to assess grid investment reasonableness.

Chapter 4 – Applying Decision Guide: This chapter applies the decision considerations to each of the priority aspects identified by the sponsoring regulatory commissions as examples.

Chapter 5 – Conclusion: Brief summary of key takeaways and recommendations.

2 DESIGN CONSIDERATIONS

2.1 DRIVERS FOR THE EVOLUTION OF DISTRIBUTION GRID

The electricity industry is facing unprecedented challenges. Fundamental changes are creating the potential for sweeping transformation of the distribution grid, which, if not addressed in a timely and thoughtful manner could impact reliability and affordability of electric service and impede the ability of policy makers to achieve other energy policy goals relevant to their jurisdictions. These changes include:

Accelerating technology innovation

Technological evolution speeds up exponentially because each generation of technology improves over the last.[38] This is happening in all areas of technology, including computing, machine learning and distributed resource technologies. For example, algorithmic efficiency improved by 30,000 times over a 20-year period from the early 1990s. This is particularly relevant as algorithms are at the core of many of the advanced analytics and control functions that, in turn, enable more cost-effective distributed resource systems. Technological advancements will continue to shape the electric industry just as it is doing in every other business sector.

Customers desire choices to manage energy costs and service quality, such as higher reliability

Customers are seeking more control over their energy bills and achieving their environmental footprint goals through adoption of DER. Customers are also increasingly intolerant of power outages. Reliability is the second major factor in customer satisfaction, behind decreased costs in electricity bills, according to the 2015 American Customer Satisfaction Index report on the electric industry.[39] Addressing these customer needs is raising the bar for distribution system requirements in planning, infrastructure and operations.

Public policy driving resiliency, resource diversity, cleaner energy, and system efficiency

State policies on resiliency, resource diversity and clean energy are shaping the development of distributed resources and are fundamentally changing the traditional centralized paradigm to a hybrid centralized-decentralized grid structure. As identified in Volume I, many states' policies also include the desire to optimize overall system efficiency through the use of distributed resources for the bulk power system and distribution grid. Achieving this integrated grid "will require planning and operating to optimize and extract value throughout the electric grid," as described by the Minnesota Public Utilities Commission.[40]

Together, these changes are driving the need for grid modernization on one or more of three dimensions, as shown in Figure 2: 1) reliability, resiliency, safety and operational efficiency, 2) integration of DER adopted by customers and 3) DER utilization for bulk power system and/or distribution operational services or infrastructure deferral. Investments may primarily be associated with one of the three dimensions, but also enable functions in the other two. Core components, as discussed in Section 2.3.4, support all three.

Figure 2: Three Dimensions of a Modern Distribution Grid

Beyond a fundamental need to improve reliability and operational efficiency, there is a need to consider the impact of DER adoption on the grid. However, DER adoption is not occurring uniformly across the U.S. Some states are already experiencing the tangible impacts of customer adoption of DERs, while other states have had very little adoption to-date. However, given accelerating technological innovation it is not a question of "if", but rather a question of "when" DER adoption will impact grid planning and necessitate additional modernization. In this context, it is useful to consider Bill Gates' observation about change, as he nearly missed the fundamental changes brought by the internet beginning in the mid-1990s:

"We always overestimate the change that will occur in the next two years and underestimate the change that will occur in the next ten. Don't let yourself be lulled into inaction."

In this context, Volume I of the Modern Distribution Grid report series starts with an assessment of state objectives for a modern grid that reflect these drivers of change. For the purposes of this initiative, an "objective" is an envisioned or desired outcome. Objectives are high-level goals for the modernized grid, such as providing reliability or enabling the integration of DER. Moving deeper beyond state objectives, desirable attributes for the grid were also identified. An attribute is a characterization of the grid compared to an objective, such as resiliency.

To establish a foundation for the Modern Distribution Grid volumes, a sample of ten states and the District of Columbia, representing a diverse cross-section of regional and regulatory environments, were selected for analysis. The sample includes California, Florida, Hawaii, Illinois, Massachusetts, Minnesota, New York, North Carolina, Oregon and Texas. To capture each state's vision for grid modernization, relevant legislative and regulatory documents governing electric utilities were examined. The literature sources are publicly available documents, selected because they represent policy-driven objectives and grid attributes. For most of the states, the objectives and attributes for grid modernization were drawn directly from legislative or regulatory documents, as it was understood that these types of documents would speak most broadly to the concerns of multiple stakeholders. The exceptions to this are North Carolina and Florida, where grid modernization legislation or regulation leaves the definition of objectives and attributes open to utilities. For this reason, literature sources in these two states also include utility filings related to grid modernization technology deployment. Figure 3 shows the prioritized objectives and attributes of these states, which recognizes a high-degree of commonality across states. Overall, the top objectives reinforce one another to advance traditional goals, through a modern grid tailored to meet 21st century challenges and customer demands.

Figure 3:Normalized State Objectives and Attributes

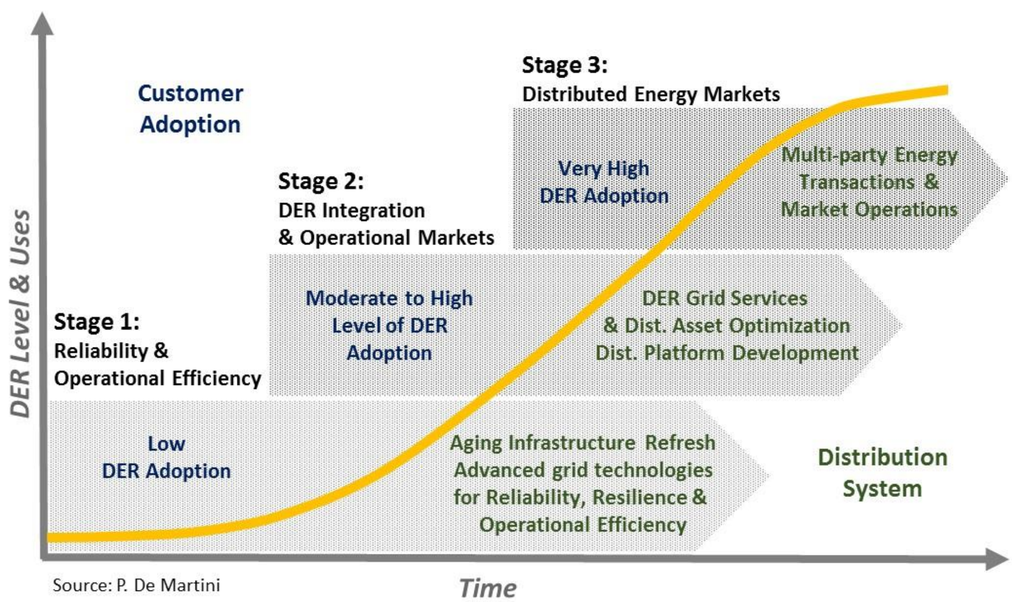
Objectives	CA	DC	FL	HI	IL	MA	MN	NC	NY	OR	TX
Affordability	●	●	●	●	●	●	●	●	●	●	●
Reliability	●	●	●	●	●	●	●	●	●	●	●
Customer Enablement	●	●	●	●	●	●	●	●	●	●	●
System Efficiency	●	●	●	●	●	●	●	●	●	●	●
Enable DER Integration	●	●	●	●	●	●	●		●	●	●
Adopt Clean Technologies	●	●	●	●	●	●		●	●	●	●
Reduce Carbon Emissions	●	●	●	●				●	●	●	●
Operational Market Animation	●	●		●		●	●		●		
Attributes	CA	DC	FL	HI	IL	MA	MN	NC	NY	OR	TX
Safety	●	●	●	●	●	●	●	●	●	●	●
Cyber-physical Security	●	●	●	●	●	●	●	●	●	●	●
Operational Excellence	●	●	●	●	●	●	●	●	●	●	●
Resiliency	●	●	●	●	●	●	●	●	●	●	●
Flexibility	●	●	●	●	●	●	●	●	●	●	●
Transparency	●			●	●		●		●		

2.2 EVOLUTION OF THE DISTRIBUTION GRID[41]

Whether the timing is driven by customers' expectations of higher reliability, technological advancements driving adoption of DERs, or by proactive market animation policies, the need to evolve the distribution grid is clear. For example, a recent Utility Dive industry survey[42] found that over 80% of respondents anticipate moderate to significant increases in distributed generation and energy storage over the next decade. A modern distribution grid will need to enable customer choice for new technologies and services, as well as to manage multi-directional flows from many resources with a variety of generation and consumption patterns. This requires the electric distribution system to become more dynamic, flexible and resilient. Distribution enhancements are also needed to integrate the value that technological advancements and distributed resources may provide in offsetting the need for incremental generation, transmission, and/or distribution capital investment. However, the pace and scope of change is very state specific.

These customer and policy drivers also create differences in the timing and pace of change. Figure 4 illustrates a three-stage evolutionary framework for the distribution system. This framework is based on the assumption that the distribution system will evolve in response to both top-down (public policy) and bottom-up (customer choice) drivers. The yellow line represents a classic technology adoption curve as applied for DER. These stages represent the levels of additional functionalities needed to achieve greater reliability and operational efficiency as well as to support increasing customer DER adoption and/or the integration of DERs into power system operations. This is the case whether the drivers are market animation policies, increased customer choice, or both. The result is an increasingly complex system.

Figure 4. Distribution System Evolution



Stage 1: Grid Modernization – In this stage, the focus of grid modernization is on enhancing reliability, resilience and operational efficiency while addressing aging infrastructure replacement. The level of customer DER adoption is relatively low and DER market participation at wholesale levels is nonexistent or limited. This level of DER integration can be accommodated within the existing distribution system without material changes to infrastructure or operations. Proactive development of integrated distribution planning is introduced to assess continued distribution grid enhancements to meet customer expectations, address technological advancements and policy objectives in Stage 2 and beyond. Most distribution systems in the U.S. are currently at Stage 1.[43]

Stage 2: DER Integration – This stage is characterized by material integration of DERs into power system operations, either through significant levels of customers' DER adoption or public policies creating market opportunities for DER in wholesale and/or distribution grid services. At higher levels of DER uptake on the distribution grid (e.g., solar farms, behind-the-meter customer resources and microgrids), operational impacts may occur, including voltage variations and bi-directional power flows. The coordination of DER participation in wholesale markets with distribution operations becomes necessary to maintain reliability and service quality. This in turn creates the need in Stage 2 for enhanced functionality related to maintaining reliable operation of the grid and optimizing the use of DERs.

Stage 3: Distributed Energy Markets[44,45] – Stage 3 involves the introduction and scaling of bilateral energy transactions between sellers and buyers across a distribution system. A prerequisite is a high penetration level of distributed resources, either behind the meter or grid connected, that can supply dispatchable energy and that are not encumbered by pre-existing net energy metering tariffs, or interconnection rules or regulations that effectively prevent the resale of the energy produced to another party across the distribution grid. It is important to note that the vast majority of energy producing DERs, such as rooftop solar, installed in the U.S. (exceptions include Texas and Hawaii) are similarly encumbered, and therefore it is unlikely that Stage 3 markets will develop until after DER rate reform and current incentives expire. However, it is likely that some limited energy transactions may occur in Stage 2 related to multi-user microgrids as discussed in the Boston harbor project,[46] for example. Stage 3 will likely occur beyond the 5-year horizon of this effort and so will not be addressed in this guide.

Considerations

Vertically Integrated versus Restructured Utilities

A question is often asked regarding the implications of this evolution on vertically integrated versus restructured utilities, or investor-owned versus publicly/community owned utilities. Distribution system issues related to the changes in the growth of customer DER and use of the grid in each of these utility structures are the same, owing to the laws of physics. The potential role of DER aggregators and customer DERs providing grid services to the bulk power system and/or distribution grid services adds further considerations. Despite whether an independent aggregator or the utility aggregates DERs for resource adequacy or for non-wires alternatives, for example, most of the same issues need to be addressed in Stage 2.

It is important not to confuse business model questions with those related to the cyber-physical distribution system and the modernization that is required irrespective of who may develop and aggregate DERs, or who may operate the grid. The grid architectural approach taken with this report is valid no matter which entity plays what business role.

It is important to not confuse business model questions with those related to the cyber-physical distribution system and the modernization that is required irrespective of who may develop and aggregate DERs, or who may operate the grid. The grid architectural approach taken with this report is valid *no matter which entity plays what business role*. Further, it is necessary to consider functional enhancements to distribution planning, grid operations and certain market operations if:

- DER adoption has created or is or expected to start creating operational challenges; or
- DERs are expected to provide an alternative to capital investment.

The term "market" is applied in the broad context of any transaction involving the use of DERs for resource adequacy and non-wires alternative irrespective of market design (e.g., tariff, program or procurement/auction).

Distribution versus Transmission System

Today's electric distribution system in the U.S. is the result of over 100 years of organic population and economic growth combined with technological evolution in electric power delivery, control systems and computing and telecommunication. The U.S. electric distribution system serves over 144 million customers through about 6 million miles of overhead lines and underground cables[47] over an estimated 500,000 circuits originating from 60,000 distribution substations.[48] Most of this infrastructure was installed over the past 50 years and is undergoing a significant refresh. This includes replacement of old electromechanical devices with digital devices such as protection relays. This infrastructure refresh largely started in the mid-2000s and will continue into the next decade given the expanse of the distribution system nationwide and in recognition of the customer affordability challenges with such a large capital investment.

Transmission systems, by contrast, were largely modernized from the 1990s through 2000s, including extensive sophisticated monitoring and controls capabilities. Distribution systems have comparatively much less sensing and automation. Additionally, the majority of transmission systems operate in redundant networked configurations that enable multi-directional energy flows. Distribution systems are largely radial in design, with the exception of network systems used in dense city environments. Also, unlike transmission, distribution systems do not operate with balanced 3-phase loading as those customers (including those with DERs) are mostly connected to a single distribution phase. Additionally, distribution systems are frequently reconfigured for maintenance and in response to outages to isolate faults and restore power. Transmission lines do not operate in this fashion. This leads to different engineering design approaches to their respective operations. These, and other factors, create substantial differences between the design and operation of transmission versus distribution systems. This is important to consider when assessing modernization efforts, particularly to integrate DERs at scale.

Common View of Objectives for Grid Modernization

Given the implications of grid evolution to customers, stakeholders and grid owners, it is essential to have a common view of what the grid needs to enable and when it is needed. This requires proactive engagement between regulators, customers, utilities and other stakeholders. There is a question for some regulators regarding whether they have the latitude to explore grid modernization absent a legislative or governor-issued directive. It may be the case however, that regulators have the authority under their respective statutory directive to ensure reliability, cost-effective service and prudent investments. In this context, regulators need to articulate what is required (objectives) and utilities should transparently develop modernization strategies and plans that are aligned with customer needs and new uses by energy service organizations (ESOs), as applicable. This also includes any necessary education given the complexity of the engineering issues, technology solutions and policy issues. In every case to-date, significant education of the issues was needed by all parties involved. As such, these efforts also place a significant resource challenge for regulatory commissions and stakeholders.

2.3 DISTRIBUTION SYSTEM PLATFORM

2.3.1 Future Role of Distribution Grids

Looking forward, the distribution grid's purpose and value can no longer be defined in terms of its traditional role to deliver the energy commodity from central station power plants out to end-use customers. As distributed technologies become increasingly cost-effective, it is important to consider instead how to create value for consumer advocates and other users to utilize the grid. Therefore, it is essential that distribution designs align to enable customer value and public policy. This need holds for any distribution utility, irrespective of industry or market structure, as the rise of distributed resources will drive fundamental changes to a distribution system.

In this context, the potential value of the grid can be viewed in relation to four potential distribution end-states: Grid as Back-up, Current Path, Grid as Platform and Convergence. These end states, illustrated in Figure 5, should be thought of as a continuum in terms of increasing grid value.[49] Grid as Back-up to customer self-sufficiency leaves the grid as a back stop. The Current Path is effectively an enhanced status quo, where information and automation technologies improve reliability and operational efficiency. Grid as Platform expands value through enabling DER integration at scale and utilization as a system and grid resource. The Convergence model goes the furthest to expand value through synergies between electric service and other essential networks, such as water and transportation, often pursued in smart city initiatives. These end-states, explained further below, can be used among regulators, utilities and stakeholders to discuss distribution system qualities that align particular customer needs and policy objectives. The focus of grid modernization efforts nationally is largely on developing the grid as a platform and seeking convergent opportunities.

Figure 5: Future End States for Electric Network

Grid as Back-up. This end-state involves the grid providing emergency back-up to a majority of customers that have become largely self-sufficient through the adoption of distributed resources, including energy storage and advanced building and home energy management systems, and microgrids. This end-state envisions a smaller number of customers remaining wholly dependent on the integrated electric system, Investment in electric distribution diminishes, focused primarily on break-fix to maintain minimum service standards and quality.

Current Path. This end-state is based on the current utility investment plans for electric distribution upgrades and smart grid technology adoption as identified in current rate cases and smart grid roadmaps. This end-state is the outcome of an incremental approach to infrastructure investment. Lack of coordination or collaboration among stakeholders can create gaps in system planning and investment. This path faces a real risk of misalignment of the timing and location of advanced technology investment or substantive changes in distribution design with the pace of customer adoption and merchant development of DER.

Grid as Platform. This end-state builds on current investments through adoption of more advanced technology into the grid, along with an evolution of distribution system designs to enable safe, reliable and seamless integration of DERs and independent microgrids to improve overall efficiency of the electric system. This envisions a proactive approach to managing the alignment of investments. The value of such a grid platform increases in relation to the volume of transactions across the system (i.e., network effects). This end-state also envisions a greater number of participating actors interacting with, and relying upon the grid. Section 2.3.2 discusses grid as platform in greater detail.

Convergence. This end-state envisions the convergence of an integrated electric network with water, natural gas, transportation systems and other essential services to create more efficient and resilient infrastructure (e.g., "smart cities") to enable long-term economic and environmental policy objectives.[50] Convergent opportunities to minimize capital investment in infrastructure for synergistic societal benefits are fully evaluated in joint planning efforts with cities/local communities. This is particularly important with increasing community development of solar projects, multi-user microgrids and district energy systems, for example.

2.3.2 Grid as Platform

An increasing number of grid modernization efforts nationally are focused on developing a distribution grid as a platform. It is this next generation platform that was the impetus for this DSPx initiative. However, the term "*platform*" has several distinct meanings which are important to distinguish, relevant to subsequent decisions regarding grid architecture and functionality.

In simple terms, there are two types of platforms that are often implied in relation to grid modernization. One type is a *transaction platform* that facilitates one-to-many markets, such as the use of DERs to provide grid services to a distribution operator or multi-sided markets, such as those which may occur in the future under Stage 3 distribution level energy transactions described earlier. Another type of platform relates to the structure of the *cyber-physical grid platform* where certain components remain stable forming the *core platform*, while other complementary modules are integrated over time through interoperable interfaces. This modularization of a complex system like the distribution grid enables functions to evolve incrementally as needs dictate, consistent with the overall architecture.[51,52] For example, the physical infrastructure of wires and transformers comprise part of the core platform, but other components, such as sensing and operational communications, should also be considered as core in a modern grid.

A modern distribution grid, as explored in this report, involves the development of a cyber-physical infrastructure platform, while other related modules enable the creation of a distribution operational market transaction platform. As such, the two platform types just described can be thought of incrementally in the following sense. The cyber-physical grid platform must exist even if only to provide traditional electric service, and must be modernized if higher DER presence is anticipated, irrespective of whether any given state jurisdiction decides to adopt a market or transactional platform. This is admittedly complicated, but the concept of platforms is important to understand in relation to the development of modernization plans and related technology investments. The use of the platform approach helps to organize, manage and operate the complexity of organizing the diversity of elements needed in a modernized distribution system. Unfortunately, these relationships are often illustrated in very complex diagrams primarily focused on information flows. Central to any development is a holistic grid architecture that clearly reflects customer needs, policy objectives, and desired grid end-states, and then applies these platform concepts to create a blueprint for success.

2.3.3 Grid Architecture

Addressing the engineering issues associated with the scale and scope of dynamic resources envisioned in legislative and regulatory objectives for grid modernization will require a systems design discipline. For this reason, this effort is grounded in the basic principles and methods of Grid Architecture as developed for the Department of Energy[53] and as discussed in Volume I.

Grid architecture is the specialization of system architecture for electric power grids. As such, it includes not just information systems, but also industry, regulatory, and market structure; electric system structure and grid control framework; communications networks; data management structure; and many elements that exist outside the utility but that interact with the grid, such as buildings, merchant distributed energy resources (DER) and microgrids. Grid architecture starts with the needs of the end users of the grid, which are shaped by public policy. This combination leads to a set of desired grid qualities.

Architectural approaches to developing a cyber-physical platform began with smart grid efforts in the 2000s and were largely based on applying information architectural approaches. These efforts, while useful, are insufficient when considering the integration of DERs and the physical and operational changes to the grid. This is because there are fundamental changes to the use and operation of the physical distribution grid that require power engineering and controls architectural consideration. Also, market platforms employing the use of DER-provided distributed grid services and/or participation in wholesale markets have significant impacts on the overall industry structure. The grid architecture must integrate not just business models, but also operational processes and physical control of the electric system. Therefore, architecture for a modern grid needs to address both the development of the cyber-physical platform and the distribution operational market platform in a complementary manner.

2.3.3.1 Architectural Considerations

The following are a few of the key architectural considerations identified in Volume I:

<u>Poor distribution grid observability and connectivity models</u> – Distribution grids have low levels of sensing and measurement, which are generally not adequate for advanced grid functions and devices to meet certain policy objectives and integrate DER adoption. This is increasingly important with higher levels of intermittent resources behind the meter DER. If DERs are participating in markets, the operational need for observability is further increased. Guidelines for distribution grid observability, strategy and sensing, and measurement system design are necessary to enable the situational awareness required to operate modernized distribution systems.[54]

<u>Growing number of grid devices to be managed, monitored, controlled and secured</u> – Very large numbers of devices with embedded processing and communication capabilities are increasing the potential efficiency of the grid. However, the addition of these devices are also increasing cybersecurity threat exposure. These intelligent devices (e.g., smart meters, other sensors and grid devices), potentially numbered in the millions to tens of millions on a particular distribution grid, must be managed in terms of provisioning, accounting, security and function to achieve the benefits and mitigate potential operational risks. It is important to consider that legacy control systems and network management systems were typically designed for sense/control endpoints numbering in the thousands to low tens of thousands.

<u>Layering, modularity & interoperability</u> – Since there is no single system or application for operating a distribution grid, multiple systems must be used and often must interchange information to do so. Integration of such systems has been expensive and time consuming. This problem can be mitigated through layered, modular architecture and use of open international standards for information exchange. Structure is overwhelmingly important in determining the capability limits and flexibility of the distribution platform.

<u>Increasing number of distribution level functions</u> – New functions are increasingly connected through the grid, adding complexity as well as hidden control coupling through grid electrical physics even when they appear to be independent (e.g., interaction between Volt-var control and demand response). This type of coupling may not be recognized until a penetration tipping point has been passed (i.e., may not show in demonstrations and pilots). This can lead to a multiple controller/multiple objective situation where applications clash in wanting to make use of the same control element or infrastructure element for differing purposes at the same time.

<u>Centralized vs. distributed control</u> – One of the key decisions about management of modernized grids is the issue of how control is performed. The traditional grid control model is centralized. In the more distributed approaches, data flows are more local and decentralized computing operating under a framework solves the control problems in a coordinated distributed fashion, with each part acting as a team member rather than as a slave to a central master. The choice between these approaches is structural (architectural) and has a massive impact on many other downstream design decisions.

Market vs. control mechanisms – As with the centralized vs. distributed issue, there are two extreme views about grid and DER management. One viewpoint is that a well-designed market with the "right rules" will provide prices that make everything work. The other viewpoint is that a proper optimal control formulation will make everything work. Both views have limitations, and in fact, both mechanisms are needed for modern grids. The key issue is to understand where each mechanism fits and how they work together.

2.3.3.2 Ultra large-scale architecture

The incorporation of advanced digital technologies and DERs into the operation of the electric system requires consideration of the information, communication and physical interfaces. For example, as the response time-frames become shorter and the numbers of interacting elements increases distribution systems are increasingly evolving from human-centric passive/reactive management to highly automated active management.[55] As such, operational systems will also evolve in complexity and scale over time as the "richness" of systems functionality increases and the reach extends to greater numbers of intelligent devices at the edge of the system. This also introduces operational risks from increases in system complexity and the cyber-attack surface.[56] This increased complexity goes well beyond traditional levels of system complexity and therefore requires new ultra large-scale layered architectural approaches.[57] Layering means allowing each of the electric system tiers (i.e., bulk power, distribution and customer) to optimize for their own objectives while also coordinating with the adjacent tier(s).

Additionally, networked distribution systems will necessarily involve technologies with different lifecycles as more digital and software components are added. Interfaces with customers and DER systems will also likely be more dynamic as these systems will have different lifecycles. These cyber-physical interfaces also become critical to achieving the desired open and flexible network. Therefore, it is essential that a systems engineering approach leveraging structural concepts and interoperability principles[58] is employed to integrate fast and slow cycle technologies.

By understanding the functional requirements and interfaces, it is possible to define boundaries to create a flexible platform system based on a stable core with modular components. This modularity would mitigate stranded cost risk and enable future optionality to benefit from unforeseen innovations such as was the case with modular smart meter designs developed before the iPhone was launched. In this example, the introduction of software applications ("apps") to monitor energy usage quickly rendered in-home energy displays that were part of many smart meter plans obsolete. The architecture of apps on a powerful personal device also has changed the view of how smart meters (and other grid devices/systems) should be designed. A modular approach involves defining discrete functions and related systems that have well defined interfaces that are standardized. This allows the system to be added like building blocks to create a technology stack as illustrated in

Figure 8. The key to modularity is defining the boundaries correctly. This is fairly complex and involves identifying those engineering-design "constraints that de-constrain".[59] This modular and layered approach is what enables the internet to foster innovation in both applications and hardware. An example

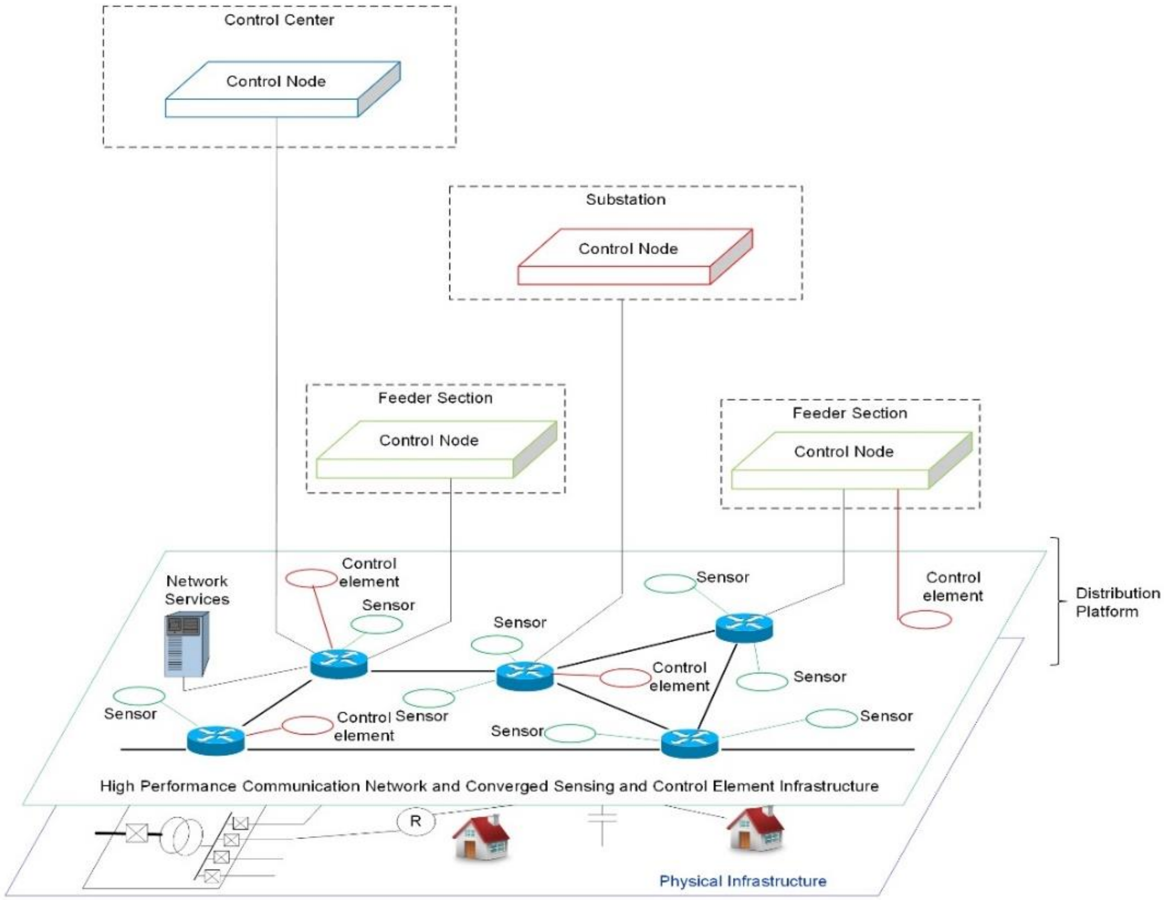
related to grid sensing and measurement and related communications networks is discussed in Chapter 4, Section 4.3.

2.3.3.3 Distributed, Layered Architecture

It is important to look at multiple levels in the entire power delivery chain rather than only focusing on distribution operations. Traditionally, those layers were individually controlled with limited control between the transmission to distribution layers and distribution to customer layers. This was because power flowed from transmission through distribution to customers – so in effect, the customer and distribution layers floated on bulk power system operations. As variable and bi-directional power flows increase and DERs begin to provide grid services, there is a need to effectively coordinate this activity. This coordination framework is the process of ensuring that distributed elements (i.e., grid components, DERs, organizations) collaborate appropriately to solve a common problem. It can involve direct control, markets, or organizational interaction rules, among other things. Coordination frameworks exist in all grids, explicitly in some places and implicitly in others, but may be incomplete or may not fit well with new grid functions. Grid Architecture treats control and coordination together, since they are closely related.

Figure 6 below illustrates the structure of a distributed control system as well as the core platform components related to physical infrastructure, controls, sensing and communications within an ultra large-scale architecture. Figure 6 also illustrates the point that distributed control includes controls that are centralized and decentralized in substations and at or near the edge (e.g., feeder in diagram). Often the term distributed is misused to refer to only edge controls, but it actually means a distributed set of controls across the several grid layers (e.g., transmission, distribution, customer) that need to operate in a coordinated manner – hence the term layered, distributed control. This structure, and related information and controls, need to be coordinated to function properly, which requires a coordination framework.[60]

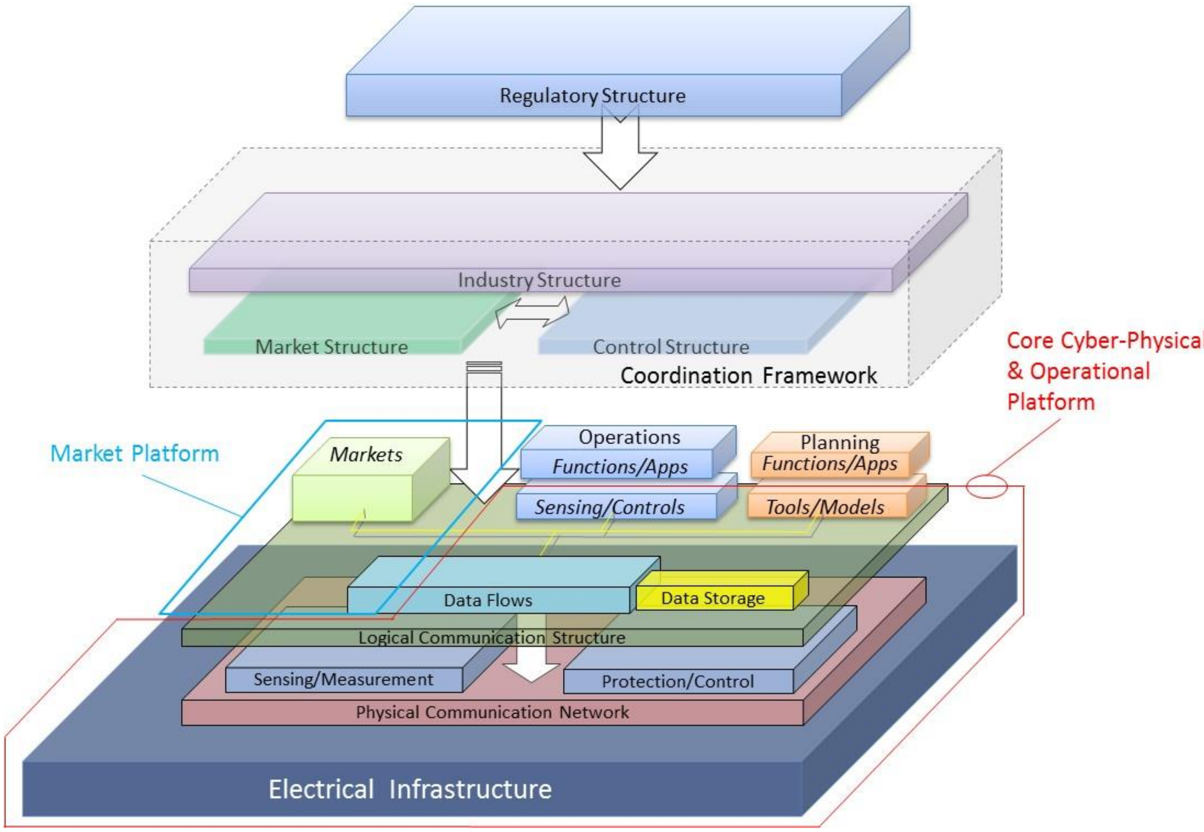
Figure 6: Layered, Distributed Control



2.3.4 Distribution System Platform

In Volume I, functions and sub-functions were identified and mapped to modern distribution grid attributes. These resulting matrices, in turn, can be used to identify those functions and sub-functions that support a preponderance of objectives and attributes. This cascading interrelationship between customer and policy objectives (regulatory structure), grid capabilities and functionality (industry structure), and the platform design, requirements and corresponding platforms are illustrated below in Figure 7. This Figure illustrates the interrelationship between cyber-physical infrastructure that comprise the core platform and the applications and market platform that dependent on the core. These in turn enable the market and control structures that along with the industry structure govern the operation of the electric system – what is also called the coordination framework.

Figure 7: Policy & Industry Structural Relationship to Platform Definition



By extension, the related technologies identified in Volume II can be derived from the Volume I analysis. These technologies are evaluated in the context of the definition of core platform and the grid architectural considerations discussed in this chapter and in Volume I. The resulting core distribution cyber-physical and operational platform components include:

- Physical infrastructure (e.g., wires, transformers, switches, etc.)
- Advanced protection and controls
- Sensing and situational awareness
- Operational communications
- Planning tools and models (e.g., DER & load forecasting, power flow analysis, etc.)

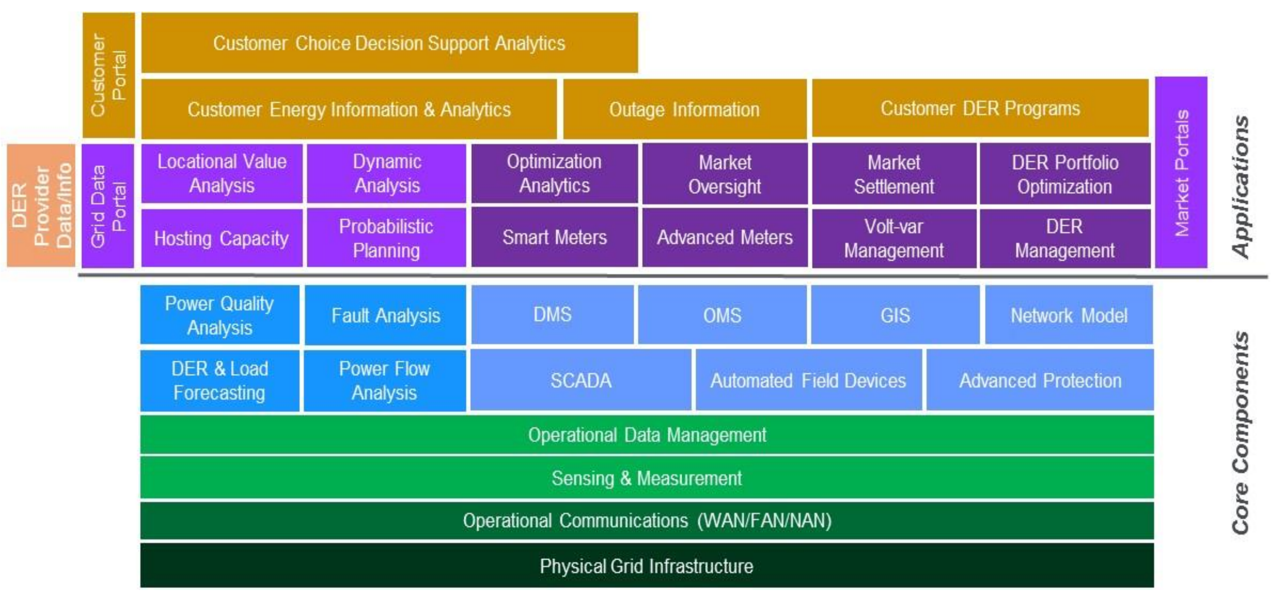
These components comprise the essential technologies that provide a foundation for a modern distribution grid. DOE's Modern Grid Initiative[61], EPRI's research[62] and others over the past 15 years have consistently identified these five categories as foundational. As such, these components may be well understood as foundational, or core components. Therefore, given these core components, the other technology categories identified in Volume II effectively become modules, or applications, that layer on top of this foundation as additional functionality is needed.

For example, integrated Volt-var optimization (IVVO) is an application that may be needed to address more sophisticated management of voltage variability on a distribution system. This application can be added when needed, leveraging the prerequisite sensing, controls, communications within the modern grid foundation. If the foundational components that can be deployed but have not yet been implemented at the time of the IVVO application, it should be recognized that the core components will support other functional capabilities and as such should be considered differently in terms of their greater inherent long-term value to customers.

This is one example of many applications than can be added as modules upon the core foundation to create a tailored next generation distribution system "platform" which, strictly speaking, is comprised of both platform components and modular applications.

Figure 8 below conceptually illustrates the core platform component and the modular application layers incorporating all the technology categories in Volume II as well as several related customer-facing technologies. This Figure translates the architectural view in Figure 7 into a logical technology stack for a modern distribution grid.

Figure 8: Next Generation Distribution System Platform & Applications



However, as noted, this does not mean that every situation needs all this functionality or system-wide deployment of the core components. Each distribution system has a unique starting point, set of drivers for additional functionality, customer value and policy considerations. Additionally, the specific technology choices within these categories, timing and pace of deployment, interdependencies of each, and the integration, interoperability and security of these components require careful consideration. In many cases, investments in several of these technologies have already begun, so another consideration is how to continue further development. This guide explores these issues in the following chapters.

3 IMPLEMENTATION CONSIDERATIONS

Implementation considerations beyond the "what" is needed, described in the previous chapter, basically involve a sequence of decisions about a) when the solution is needed, b) how fast and what scale should it be implemented, c) alternatives regarding who may provide the solution, and d) the cost-effectiveness of the solution. This chapter explores each of these aspects in the recommended logical sequence for developing grid modernization plans.

3.1 WHEN

This discussion addresses the timing alignment issues regarding customer needs and policy objectives in relation to implementation lifecycles as well as technology adoption considerations.

3.1.1 Deployment Aligned to Customer Value

Modernizing the distribution system should provide value for all customers to be sustainable. In addition to traditional customer value from safe, reliable delivery of power, there are three strategic concepts considered today by policy makers and others:

- Adopt technology innovations to increase customer value, system reliability and resilience
- Enable customer choice at the pace of customer DER adoption; and
- Create markets for DERs which in turn will create customer value through system efficiencies

As discussed above, the pace of deploying foundational investments can be tied to customers' expectations, an increase in organic customer DER adoption, or deployed to enable a merchant based model driven by wholesale market opportunities or as non-wires alternatives to distribution investment – or in ways we have not yet envisioned for each state. Under New York's Reforming Energy Vision (REV), for example, a key strategy is to "enable third parties the opportunity to provide cost-effective market solutions to identified energy needs, and drive consumer value related to the regulated distribution system"[63]. Such an approach is expected "to maximize option value of the distribution system for consumers through better planning, system operations and management and vastly scaled integration of DER".[64] The value described is related to the potential power system and societal value that DERs may provide as summarized in from California.

Figure 9: California DRP Working Group Potential DER Value

	Value Component	Definition
Wholesale	Regional Bulk Power System Benefits	Regional BPS benefits not reflected in System Energy Price or LMP
	CA System Energy Price	Estimate of CA marginal wholesale system-wide value of energy
	Wholesale Energy	Reduced quantity of energy produced based on net load
	Resource Adequacy	Reduction in capacity required to meet Local RA and/or System RA
	Flexible Capacity	Reduced need for resources for system balancing
	Wholesale Ancillary Services	Reduced system operational requirements for electricity grid reliability
	RPS Generation & Interconnection Costs	Reduced RPS energy prices, integration costs, quantities of energy & capacity
	Transmission Capacity	Reduced need for system & local area transmission capacity
	Transmission Congestion + Losses	Avoided locational transmission losses and congestion
	Wholesale Market Charges	LSE specific reduced wholesale market & transmission access charges
Distribution	Subtransmission, Substation & Feeder Capacity	Reduced need for local distribution upgrades
	Distribution Losses	Value of energy due to losses bet. BPS and distribution points of delivery
	Distribution Power Quality + Reactive Power	Improved transient & steady-state voltage, harmonics & reactive power
	Distribution Reliability + Resiliency	Reduced frequency and duration of outages & ability to withstand and recover from external threats
	Distribution Safety	Improved public safety and reduced potential for property damage
Customer & Societal	Customer Choice	Customer & societal value from robust market for customer alternatives
	Emissions (CO2, Criteria Pollutants & Health Impacts)	Reduction in state and local emissions and public and private health costs
	Energy Security	Reduced risks derived from greater supply diversity
	Water & Land Use	Synergies with water management, environmental benefits & property value
	Economic Impact	State or local net economic impact (e.g., jobs, investment, GDP, tax income)

In practice, these concepts are usually considered together. That is, in most instances, pursuing market animation without some level of DER adoption is unlikely to succeed given that distribution market opportunities for non-wires alternatives are relatively modest in comparison to those potentially present in wholesale markets where available and needed.[65] Additionally, the value from merchant activity alone is unlikely to satisfy the market opportunity needs of ESOs and so DER adoption by customers combined with wholesale/distribution services is more typically pursued. For strategic planning, it is important to consider both approaches and the implications of the different timing and functional capabilities that are required for DER integration and those for DER utilization as well as their respective incremental costs-benefits.

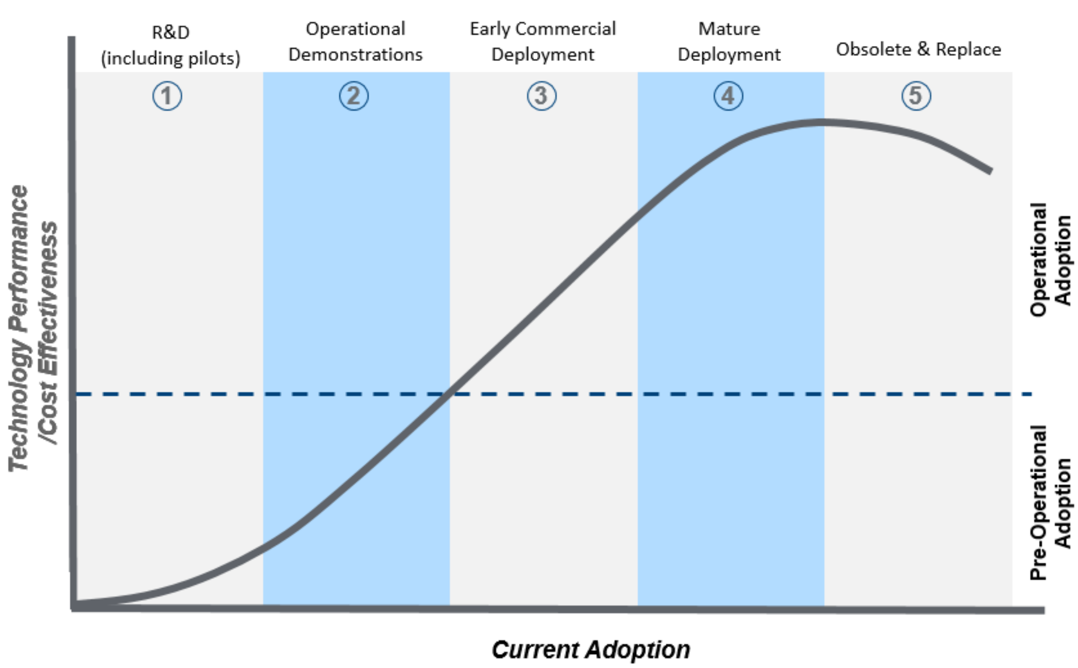
3.1.2 Deployment Timing Factors

The pace and scope of change reflected in distribution investment plans may not be sufficient to meet customer needs and policy objectives. This is due in part to DER adoption, both the time to interconnect and the potential future adoption rates (potentially accelerated), will always occur on a timeframe that is faster than new grid infrastructure implementation.

3.1.2.1 Grid Technology Innovation

Volume II employs a typical progression of the technology adoption cycle from research and development (R&D) through mature deployment and eventual obsolescence. The modern grid technologies identified in this volume are used to plan and operate critical electric delivery services with reliability and safety as key performance metrics. This drives a technology adoption cycle that is fairly conservative by necessity, meaning the technology must be demonstrated or proven to be reliable. This is similar to other industry sectors with critical infrastructure and services that demand very high levels of operational performance, such as the airline industry.

Figure 10: Technology Adoption Cycle



The technology adoption cycle X-axis, "**Current Adoption**," identifies the stage of adoption for a specific technology. The horizontal dashed line represents the crossover point from stages that are **Pre-Operational** (i.e., under test and/or evaluation) to those designated as **Operational** (i.e., proven and in production use). Phases of maturity differ by specific technology, but all technology undergo the same five phases.

The development and adoption of key grid technologies are lagging the need in several states, as customer rates of adoption (and the offerings of 3rd-party service providers) have outpaced the deployment of grid systems that can enable their effective integration. The rate of deployment is often stimulated through various public policies. Hence, it is important to understand the relationship between DER adoption rates, the stimulatory effect of policies, and the pace at which the distribution system needs to be upgraded or modernized.

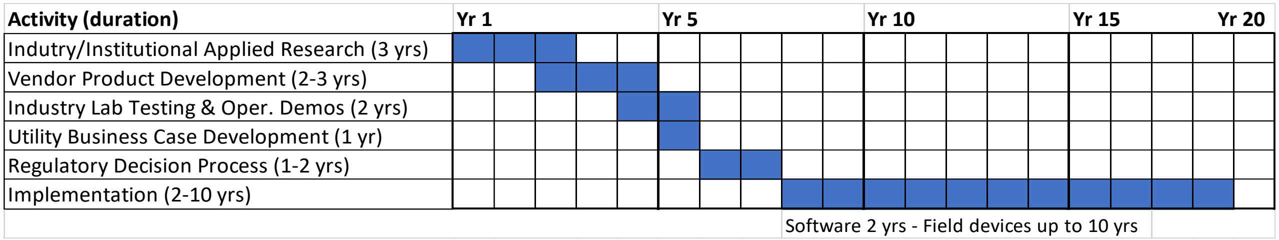
Many papers and requirements have been developed over the past ten years regarding the need for advanced distribution infrastructure and operational systems. Only recently, however, has there been sufficient demand for technology firms to invest in product development for several key technologies identified in Volume II. As discussed, many of these technologies are at early stages of development. Under favorable conditions, new product development can take several years to become operationally viable to deploy operationally. Achieving this rapid pace of development requires close collaboration between technology firms and utilities to refine, test and operationally demonstrate the products as part of a structured applied research, development and demonstration program (RD&D). Some of the lab testing may be performed in collaboration with the national laboratories' testing facilities to minimize the need for a proliferation of tests and pilots on the same/similar functions during the early development stage. However, operational demonstrations are generally required for new technology as part of the commercial product acceptance tests.

3.1.2.2 Commercial Deployment

Reducing uncertainty is important as the time cycle for new operational technology products from applied research through system-wide deployment are long. At first glance, many believe this time cycle is far too long – incorrectly comparing the adoption cycle of consumer electronics from the time they reach market to consumer purchase. At closer look, it becomes clear why the overall duration for technologies deployed at scale in the grid or grid operating systems may take between 5-10 plus years.

First, the time before a product is commercially ready for system-wide deployment needs to be considered, as described above. Also, the regulatory approval process through general rate cases or separate applications can add between 1-2 years depending on the size and complexity of the proposal. Deployment timelines are driven by the technology to be deployed. Large operational software can take about 2 years, while system-wide deployment of field devices can take up to 10 years, depending on the number of devices and the complexity of the field replacement/installation. Figure 11 below is a conceptual timeline for electric industry product development and adoption. This timeline does not reflect potential re-work loops if products do not pass tests, business cases do not pass regulatory review or products fail or become prematurely obsolete during deployment. Additionally, product development in the electric industry is often ad hoc. Various technology firms often work on different solutions at differing stages of development that will combine to enable the platform discussed. This means some products are available now, or at least in demonstration mode ahead of utility business case development, as well as regulatory decision process. It would be beneficial if the industry (e.g., utilities, regulators and tech firms) developed a vision for the grid of the future and for policy to support RD&D efforts to accelerate vendor product development and testing.

Figure 11: Operational Technology Development & Adoption Timeline



3.2 HOW

The orientation of this Modern Distribution Grid report (all 3 volumes) is that functional capabilities and related technology investments should be driven by customer needs and public policy. This line of sight approach inherently aligns investment to customer and societal value. However, the complexity of implementing and integrating various technologies, perhaps at an early stage of maturity, makes deployment more challenging, and increasingly risky.[66]

Risks also include the potential to mismatch timing with need, as highlighted above, on the relatively fast-cycle of DER and customer technology innovation and adoption in relation to grid technology product development, investment approval and deployment time cycle. Additionally, modernization is starting from a large existing infrastructure that is a combination of old and new elements. Modernization plans needs to consider how to manage the transition from or integration with legacy systems while continuing to provide reliable and safe grid operation. Therefore, "how" technologies are deployed is critically important. This section will discuss a general framework for understanding how various technologies may logically be deployed.

3.2.1 Flexible Approach

The many considerations raised in this three-volume report point to the need for a flexible, adaptive approach to implementation of a modern grid. Managerial flexibility, for example, is needed to defer, avoid, proportionally deploy, and adapt to technological innovation. This is especially necessary given the expected long transformation time that modernization will take in most instances. Such flexibility designed into a roadmap and implementation can create value for customers as described below in the discussion on real options. There are two complementary ideas on crafting such a flexible approach; *logical progression* and *proportional deployment*.

3.2.1.1 Logical Progression

> ***Too often, grid modernization and distributed resource integration stakeholder discussions are stalled due to ambiguity on desired customer and policy outcomes, and in which the "perfect" solution is clouding the "good enough" solution that achieves the majority of net value potential for all customers.***

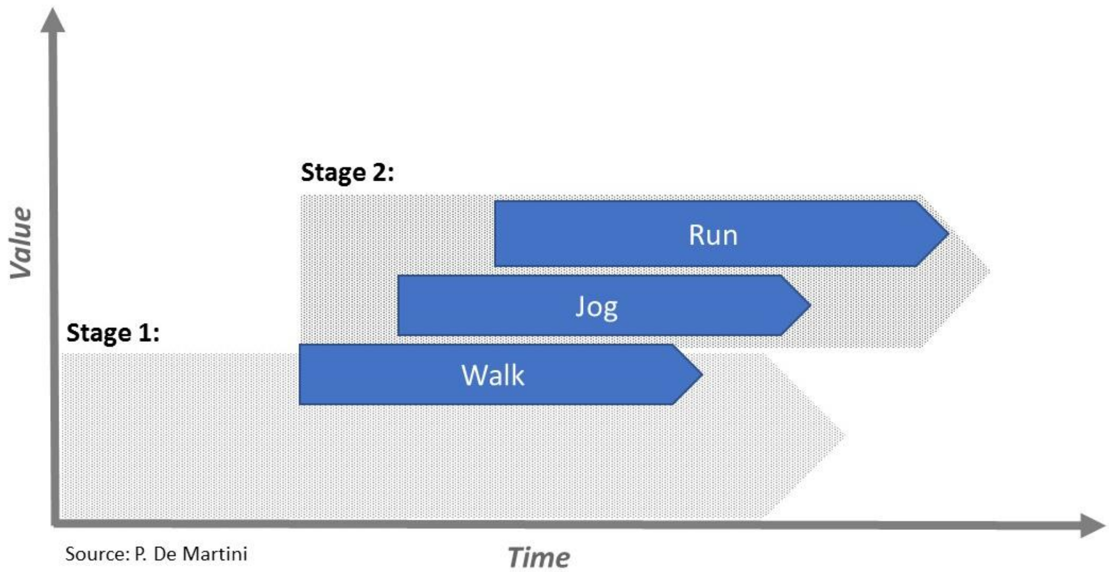
Most of the discussions in the U.S. are about the evolution from Stage 1 to Stage 2 functionality as discussed in this Modern Distribution Grid series. Nearly all U.S. distribution systems today are in Stage 1, with some utilities taking steps toward Stage 2. So, every jurisdiction/utility situation will need to first assess the starting point – that is the "Start Here" point within Stage 1. There is no generic starting point applicable to all jurisdictions and utilities. Next, clarity on what is the objective and corresponding functionality desired in a defined period of time is critical. Set clear functional objectives and time horizons for desired outcomes. Too often, grid modernization and distributed resource integration stakeholder discussions are stalled due to ambiguity on desired customer and policy outcomes, and in which the "perfect" solution is clouding the "good enough" solution that achieves the majority of net value potential for all customers.

The first is to identify a logical progression in the relative sophistication or complexity of a functional enhancement or new functionality in relation to the starting point and what level of functionality is needed. If the process changes are significant, the technologies are relatively immature or implementation is complex, it probably makes sense to take a multi-step approach. Start with the most simple and mature solution ("walk"), then add additional capability as available/needed ("jog") and then migrate to the final step ("run") of functionality desired as illustrated in Figure 12 below. This type of "Walk/Jog/Run" stepwise approach[67] follows two important ideas that should shape any grid modernization effort, *Occam's Razor*[a] and *Pareto's Principle*[b]. In effect, the objective of modernization is to identify the simplest path to achieve the desired outcomes and taking a series of steps focused on those investments that yield the most customer value. It is also important to note that, depending on the pace of policy, technological advancements, and levels of deployment, states may be in the "Walk" stage for certain components and "Jog" stage for others.

[a] Occam's Razor is a principle regarding when two competing theories that make exactly the same predictions, the simpler one is the better.

[b] Pareto's Principle (80/20 Rule) is a business rule of thumb that recognizes the disproportional relationship between certain inputs and related output. For example, as Pareto noted, 20% of the peapods in his garden contained 80% of the peas.

Figure 12: Walk, Jog, Run Approach



Source: P. De Martini

A "Walk, Jog, Run" approach is being used in California[68], New York[69] and elsewhere to manage such a transition. For example, in the case of hosting capacity analysis, one might start with more simple analysis leading over time to more sophisticated uses, for example, begin with a) providing indicative information to DER developers through heat maps, followed by b) its use in annual planning to forecast additional upgrades to enable greater customer adoption of DERs, and then c) applying the DER information in reducing the time for interconnections decisions with on-line automated tools.[70] Each of these steps is based on increasing sophistication from the underlying planning tools that themselves are in development by technology vendors. Pilot programs have also been used to explore further sophistication and in determining appropriate levels of functionality.

3.2.1.2 Proportional Deployment

Grid investments need to provide tangible value for customers and all stakeholders including utilities. The challenge is addressing the uncertainty in the scope and pace of customer needs and the effects of policies. As described, grid modernization involves multi-year (perhaps a decade or more) efforts for technologies to be deployed. This dynamic creates several risks related to technology obsolescence due to rapid innovation, implementations mismatched to needs (under-build and over-build), and misalignment of investment to customer value. It is essential that any plan be linked to a robust planning process and methods that are based on clearly understood and transparent assumptions of customer needs, policy objectives and corresponding forecasts of distributed energy resources and load.

Designing flexibility into an implementation plan can help mitigate these risks and increase customer net value. Such flexibility leverages effective architectural principles described in Chapter 2 along with interoperability based on open standards as a starting point. Flexibility involves designing optionality into a multi-year deployment. Such optionality could include technology on-ramps to accommodate important advancements that develop, including intermediate decision points to reprioritize modular deployments by deferring installation on one feeder to focus on another as needs change, for instance. Also, leveraging investments in a common core platform (even incrementally) will enable the ability to deploy tailored bundles of technologies in the field to address the specific needs proportionally. However, the economics and customer value of an investment may support a system-wide or full implementation, as is the case with certain software systems.

Also, deployments generally involve relatively large expenditures on a system-wide level that may be able to be deployed on a localized basis to address specific needs and, over time, expand based on needs to encompass the whole system. This type of surgical approach may allow for changes in prioritization of deployment as customer needs and system issues may evolve over time. An annual reassessment of the prioritization of grid modernization investments, not unlike those for the physical grid, could be done. This would require a different approach to considering grid modernization investments as less deterministic and instead as more of a set of investments to be deployed in an agile manner. For example, instead of using the typically deterministic AMI business case approach of the 2000s[71] – allow instead annual capital and expense re-prioritization in response to changes in needs. This is not unlike the methods traditionally used in annual grid planning to address reliability and safety needs. This would require regulatory review of reasonableness to allow such flexibility in implementation.

3.2.2 Legacy Transition Factors

All grid modernization planning starts with an assessment of the current state of the distribution system to understand the starting point. These starting points are not green fields – they are a compilation of decades of prior investments with a range of older and newer technologies, and often include structural constraints that may require adjustment. Historically, grid systems/devices were largely proprietary systems, unlike modern information and operational systems that are based on more effective architectures and interoperable standards. So, initial deployment planning efforts need to consider the integration of modern information and telecommunications with distribution control systems and advanced field devices on legacy cyber-physical infrastructure.

Many of these new systems need to interface with each other as well as with older systems to function and achieve operational benefits. Unfortunately, integration of open interoperable systems with legacy proprietary vendor systems can lead to very expensive system integration costs – as much as 3-5 times the cost of the underlying new software application. The architectural approaches discussed earlier can mitigate some of this, but not all and will need to be considered in any implementation plan.

In addition, most of the older systems had few security features and did not account for cyber security sufficiently in today's more connected environment. This is especially true given the threat levels addressed in the National Institute of Standards and Technology (NIST) guidelines[72]. Also, it is important to keep in mind that about 97% of total circuit miles of the U.S. electric grid is distribution. As such, it is not explicitly covered by the North American Electricity Reliability Corporation (NERC) Critical Infrastructure Protection requirements or other similar cyber security imperatives. Distribution is regulated by state commissions or local boards. The evolution of a distribution with large numbers of DER and Internet of Things (IoT) devices is creating a significant gap for electric system security. New grid technologies are increasingly meeting cybersecurity best practices, but the integration with older distribution systems/equipment and interconnected DER will need careful evaluation of cyber exposure.

3.3 WHO

Development of a modern grid raises questions about who may provide the most cost-effective technology needed for a modern grid including alternatives to traditional utility capital investment. These technology alternatives related to grid modernization might include software-as-a-service, cloud-based computing, leasing telecommunications, and leveraging ESO and/or 3rd party investments. This does not include utility infrastructure upgrades that may be avoided or deferred through treatment of DER as non-wires alternatives. When choosing its path, a utility must develop a full and accurate understanding of each alternative's ability to support the required functions. This section discusses the alternatives at a high level. Chapter 4 explores specific details of the alternatives in the context of several modern grid examples.

3.3.1 Utility Capital Investment

Traditional investment in distribution infrastructure and modernization (e.g., smart grid) is done largely through utility capital investment. This is the current approach for advanced technologies that are part of the physical electric distribution grid, such as advanced switches. This also extends to any technologies that require direct connection to a distribution feeder, such as fault current indicators. Capital investment may also make the most sense for long-lived assets due to their long depreciation periods and lower potential rate impacts when compared with short-lived assets, such as software, or the operational expenses under an outsourced services arrangement.

3.3.2 Utility Outsource

Technologies supporting modern grid functions can be provided through outsourced solutions, such as software-as-a-service and cloud computing, which are commonly treated as a utility operating expense. Since outsourcing arrangements are often priced per user or device, this approach might make sense so long as the scale of the implementation is relatively small in relation to the utility's cost to license and implement its own system. However, when the ultimate scale of implementation is very large and reached quickly, it is possible that the rate impact of outsourcing will be higher than if the utility implements the system as a capital investment.

If outsourced systems and utility systems lack true interoperability, then a vendor's technology upgrade could necessitate significant changes to system interfaces and data management at the utility.

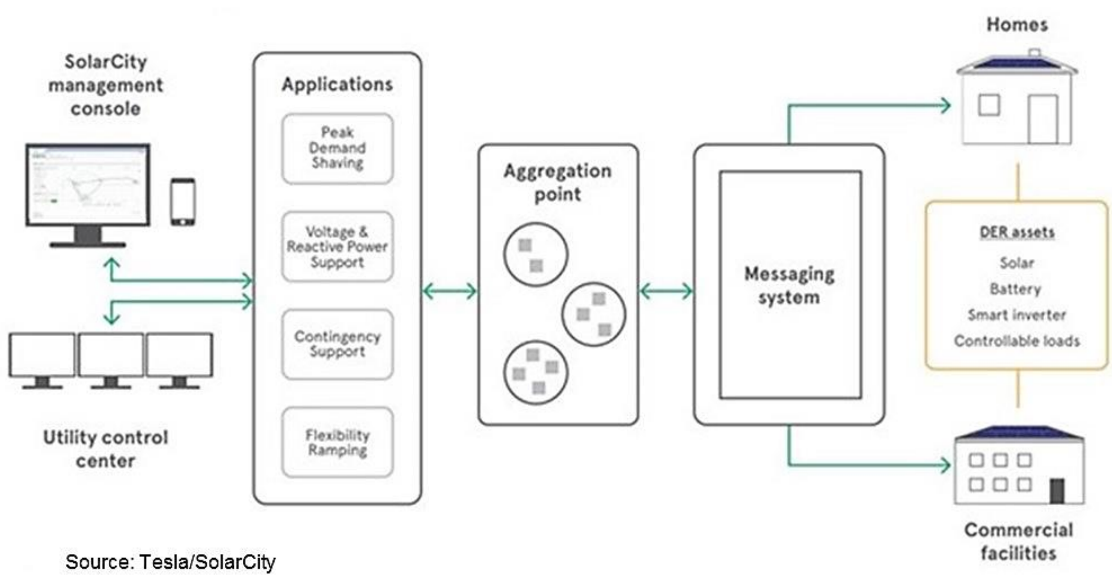
System outsourcing can mitigate some technological advancement risk since it is typical for the service vendor to periodically upgrade the outsourced system as part of the service. However, this is not without a cost. In most cases an outsourced system is integrated with one or more other utility systems; consequently, if the outsourced system(s) and utility system(s) lack true interoperability (which is very often the case), then a vendor's technology upgrade could necessitate significant changes to system interfaces and data management at the utility.

System outsourcing is increasingly being considered as a suitable alternative for non-critical utility applications. However, cybersecurity issues will vary for the type of system function. For example, critical operational functions like SCADA and DERMS will require greater cyber security evaluation when considering outsourcing to a cloud service. Nevertheless, with appropriately rigorous provisions for cybersecurity, outsourced systems can perform critical operational functions. Specific uses of potential utility outsourcing are discussed in Chapter 4.

3.3.3 ESO/3rd Party Provided Functions

It is possible that utilities can reduce their costs by using the capabilities of technologies deployed by ESOs and/or 3rd parties. Efforts to understand those capabilities and their potential uses are underway. In general, ESOs and other 3rd parties are deploying and/or aggregating DERs that have built-in sensing, measurement, control, and communications capabilities. Devices installed at customer premises typically connect to the customers' onsite Ethernet or Wi-Fi communications and communicate with the ESO/3rd party back-end device management, data management, and control systems through the customers' internet service provider (e.g., cable, wireline or mobile wireless). The level of cybersecurity with these systems is unclear and must be addressed, given the increasing role these resources are playing in the power system. This is illustrated in the SolarCity graphic in Figure 13 below which is typical of most DER aggregators.

Figure 13: SolarCity DER Aggregation Architecture

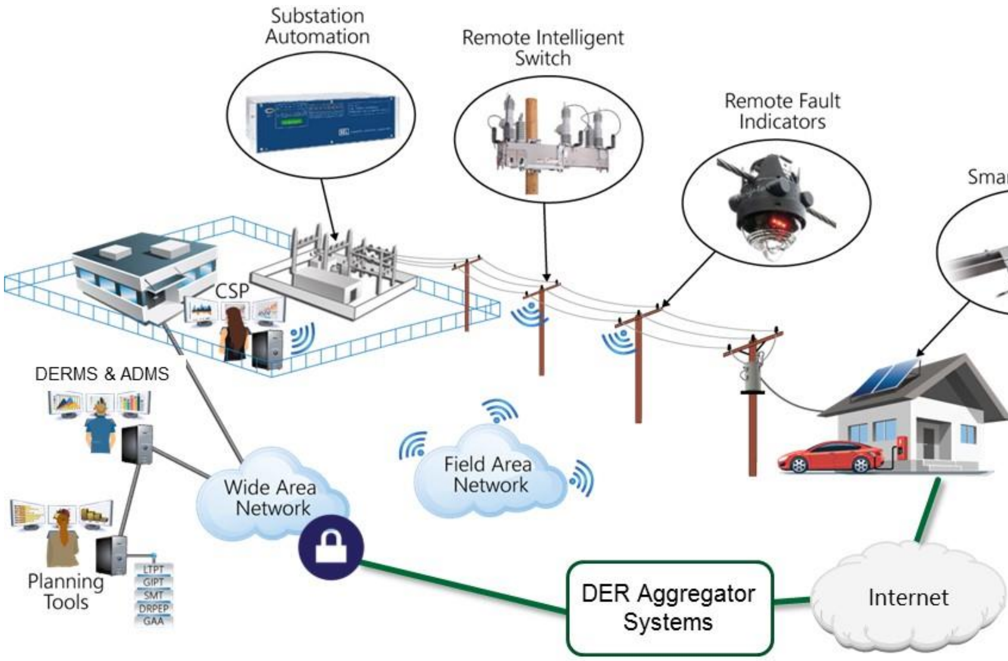


Source: Tesla/SolarCity

Some ESO/3rd party capabilities might provide alternatives to utility capital expenditures; however, there are some important considerations. First, the ESO/3rd party system manages and operates DERs that are specific to the ESO/3rd party and does not interact with any part of the grid itself (such as distribution grid sensors, equipment controls, and switches). Instead, the ESO/3rd party system can potentially provide services to a grid and/or bulk power system operator by controlling and acquiring data from its affiliated DERs with a secure interface with the utility control center at the cloud interface in Figure 13. The ESO/3rd party communication pathway through the internet and over a customer's on-premises network connection is not able to communicate with grid field switches or other grid devices (which are not connected to the internet for very good reasons). This may be obvious, but there have been extensive discussions about this very issue over the past couple of years. The ESO's assets are not a substitute for the utility's grid sensing, communications, and control systems.

Second, ESO/3rd party systems might provide alternatives for DER sensing and by extension support situational awareness, as highlighted in the ISO/RTO Council's recent report.[73] For example, access to this information could alleviate the need for utility investment in grid edge sensors for monitoring DER performance. Third, an ESO's control system that directly controls DERs might eliminate the bulk power and/or distribution operator's need for direct DER control. Instead, utility grid control systems (e.g., DERMS) would interface with the several ESO's expected for a viable market as illustrated in the Figure above. Further, ESOs' systems could reduce or eliminate a utility's need for systems and processes supporting DER and inverters device and communications management. Figure 14 below illustrates the holistic and complementary approach suggested by the SolarCity system diagram above. In this closed loop system, the DER and/or ESO's system provides feedback to the operator to optimize and control grid equipment in response to changes in the distribution system that are impacted from both participating DERs and traditional loads that aggregate to the distribution circuit.

Figure 14: Complementary ESO-Grid Operator Architecture



Adapted from Southern California Edison

An important aspect to consider is that not all customer DER will be aggregated and will still need to have a level of visibility to the grid operator. Also, more than one ESO will likely exist in a jurisdictional area and very likely customers with change ESO providers often as has been seen in retail energy services. This means the operational coordination with ESOs will need to be standardized as will the DER (including inverters) communication and information protocols. This may be done through market participation rules and/or interconnection standards. There are additional considerations regarding the use of ESOs system that are discussed in several relevant examples in Chapter 4.

3.4 COST-EFFECTIVENESS

Chapter 2 highlights core platform and modular components in the context of grid modernization investments within three areas a) reliability and operational efficiency, b) DER integration and c) DER utilization. Investments related to each of these three areas can be appropriately evaluated using one or more of the traditional and emerging methods for financial analysis. A challenge is that core platform technologies and some other investments support multiple needs in each of the three areas. As such, an important starting point is developing a holistic framework for evaluating various grid modernization investments and their implementation due to the complexity. This section discusses methods for evaluating grid modernization investments and potential applications within the framework introduced below. This section does not directly address methods for evaluating non-wires alternatives, such as DERs providing distribution capital deferral or Volt-var services. This chapter address all the modern grid technologies identified in Volume II.

3.4.1 Cost-Effectiveness Framework

There is an identified need for a common framework for evaluating costs and benefits associated with grid modernization investments. This is complex due to the various uses of the investments and the various approaches to implementation. For example, how should existing grid investments in aging infrastructure be assessed? Also, what methods may be better to assess benefits in relation to certain investment costs? This latter question may involve traditional utility benefits or as proposed in several states, including benefits that accrue on the power system outside of the utility (e.g., wholesale market benefits) and societal benefits (e.g., environmental).

Within this context, grid modernization expenditures generally fit into one the following four categories[74] in the framework below. Note that, except for category 4, the costs of these grid expenditures tend to be socialized over the distribution utility's entire service area.

Table 1: Grid Modernization Cost-Effectiveness Framework

No.	Expenditure Purpose	Methodology
1	Grid expenditures to replace aging infrastructure, new customer service connections, relocation of infrastructures for roadwork or the like, and storm damage repairs.	Least-cost, best-fit or other traditional method recognizing the opportunity to avoid replacing like-for-like and instead incorporate new technology
2	Grid expenditures required to maintain reliable operations in a grid with much higher levels of distributed resources connected behind and in front of the customer meter that may be socialized across all customers.	Least-cost, best-fit for core platform, or Traditional Utility Cost-Customer Benefit based on improvement derived from technology.
3	Grid expenditures proposed to enable public policy and/or incremental system and societal benefits to be paid by all customers.	Integrated Power System & Societal Benefit-Cost (e.g., EPRI and NY REV BCA)
4	Grid expenditures that will be paid for directly by customers participating in DER programs via a self-supporting margin neutral opt-in DER tariff, or as part of project specific incremental interconnection costs, for example.	These are "opt-in" or self-supporting costs, or costs that only benefit a customer's project and do not require regulatory benefit-cost justification.

3.4.2 Methods

Discussion of the methods for evaluating grid modernization will focus on categories 2 and 3 in the framework above, as these expenditures relate to the functional enhancements described in Volume I and the related technologies assessed in Volume II and shown in Figure 8.

3.4.2.1 Least-Cost, Best Fit Method

This traditional method may be the most practical approach to evaluating core platform investments under category 2 above. This includes investments in the five core categories identified in Chapter 2:

- Planning tools and models
- Physical infrastructure (e.g., wires, transformers, switches, etc.)
- Advanced protection and controls
- Sensing and situational awareness
- Operational communications

The first step is to assess the "fit" against the "need" as defined in a related grid architecture and design that satisfy the functional needs aligned to the pre-determined customer and policy objectives. This best-fit assessment is applied to certain grid technology solutions to narrow the potential options. Afterwards, the least-cost can be assessed through various means. Most typically, this determination is the result of a competitive procurement. It should be noted that states have varying approaches to least-cost, best-fit that may also alternatively be assessed as best combination of expected cost and risk.

3.4.2.2 Traditional Customer Benefit-Utility Cost

Traditional benefit-cost methods are focused on the customer benefits that accrue to customers through operational and capital expenditure savings and reliability improvements. The costs are related to the investments and operational expenditures needed to enable the savings. These traditional analyses do not include external benefits outside the utilities' scope of operation as framed by a revenue requirement. For example, they don't include societal benefits from reducing greenhouse gas. This type of Benefit-Cost Analysis (BCA) is generally applicable to those non-core, modular grid modernization investments related to enhancing reliability and operational efficiency. These technologies include smart meters, advanced meters, Volt-var management, and optimization analytics as identified in Figure 8. Advanced planning tools, while a modular type of investment, are relatively small and don't warrant a BCA to justify, if the engineering need is determined.

3.4.2.3 Integrated Power System & Societal Benefit-Cost

An integrated power system and societal BCA may be useful to evaluate the cost-effectiveness of certain grid investments in relation to the value potential from enabling customer DER integration and/or utilizing DERs. This assessment would be done as part of the ongoing integrated system planning (i.e., resource, transmission and distribution) process that evaluates the net benefits of resources and required enabling grid investments. In this case, the benefits are associated with the resources and the grid investments are offsetting costs to yield net benefit for customers.

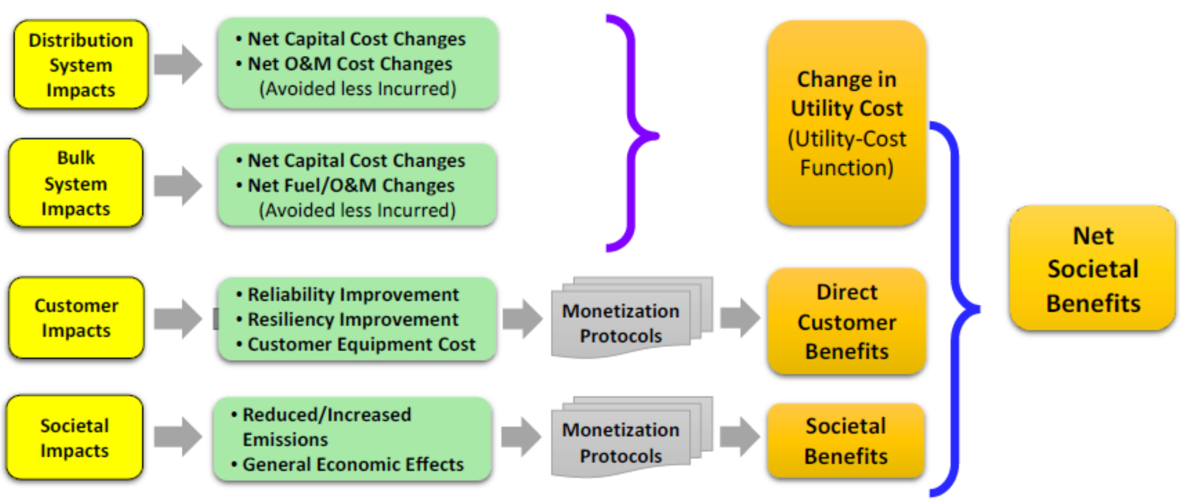
This approach may be applied to non-core, modular investments in category 2 and those investments in category 3 (e.g., DERMS, DER portfolio management, and other market enabling technologies shown in Figure 8). This may also include energy storage for grid operations and potential grid upgrades to increase

DER hosting capacity. The application of this method presumes that the cost of the investment, if beneficially positive, would be borne by all customers since they enable the associated DER value.

Additionally, an integrated system planning process typically occurs before an application for the related grid investment. Therefore, if the DER resource plan was determined to be beneficial, then the associated grid costs will have been justified. As such, subsequent funding request for the grid investment should be based on least-cost, best fit.

EPRI's Integrated Grid Benefit-Cost Framework is organized around four categories of impacts: 1) Distribution System Impacts, 2) Bulk System Impacts, 3) Customer Impacts and 4) Societal Impacts, as depicted by Figure 15.[75] States have adapted EPRI's BCA model and its methodology to align with their states' objectives. Note that customer impacts also include reduced energy and related billing costs.

Figure 15: EPRI's Integrated Grid BCA Methodology



Several states have begun to define more specifically the "Impacts" groups identified in EPRI's model above. For example, New York's 2015 BCA Framework[76] lists the following elements to evaluate:

Table 2: New York REV BCA Benefit Elements

Bulk System	Avoided Generation Capacity (ICAP), including Reserve Margin
	Avoided Energy (LBMP) Avoided Transmission Capacity Infrastructure and related O&M Avoided Transmission Losses
	Avoided Ancillary Services (e.g., operating reserves, regulation, etc.)
	Wholesale Market Price Impacts*
Distribution System	Avoided Distribution Capacity Infrastructure
	Avoided O&M
	Avoided distribution losses
Reliability/resiliency	Net Avoided Restoration Costs

	Net Avoided Outage Costs
External	Net Avoided Greenhouse Gases
	Net Avoided Criteria Air Pollutants
	Avoided Water Impacts*
	Avoided Land Impacts*
	Net Non-Energy Benefits (e.g., avoided service terminations, avoided uncollectible bills, health impacts, employee productivity, property values, to the extent not already included above)*
	* see original reference paper

While BCA methods like EPRI's are discussed in terms of evaluating grid investments, it is more correct to describe them in terms of assessing the net value of DERs at a location on the distribution system. The necessary grid investment is an offsetting cost. In New York, this type of BCA is used to assess the value of DER and the corresponding cost-effectiveness of grid investments. The NY PSC staff whitepaper[77] described their approach as:

"The focus of our BCA framework development will be on four categories of utility expenditures: (i) utility investments to build [Distributed System Platform (DSP)] capabilities;2 (ii) procurements of [Distributed Energy Resources (DER)] via selective processes; (iii) procurement of DER via tariffs; and (iv) energy efficiency programs. The extent to which BCA can be formulaically applied will depend on the type of activity and the range and time frame of potential benefits and costs."

In California, by contrast, the locational net benefits analysis (LNBA) refers to only the net present value (NPV) of the DER benefit streams from providing operational services. It does not consider the cost of grid modernization investments necessary to enable those DER services.[78] Ongoing LNBA Working Groups discussions are considering the methods and applicability of locational value for DERs and evaluating grid investments.[79]

3.4.2.4 Real Option Analysis

Given the level of uncertainty, a grid modernization investment strategy that incorporates flexibility to defer, stage, expand or abandon can improve customer value under various possible scenarios. This flexibility, to create real options, needs to be incorporated into the architecture and design of the implementation from the start. In simple terms, building flexibility into modernization systems is attractive if the present value of the cost of changes (including potential stranded assets) that may be required later is far greater than the additional cost of designing flexibility into the implementation.[80]

Real options analysis, unlike NPV used in the BCA methods described above, can account for the benefits of unforeseeable technologies and services that are likely to emerge over relatively long implementation periods (e.g., for grid field devices). Options analyses address the flexibility designed into implementation and account for uncertainty, such that an investment that was considered marginal under a traditional NPV analysis may be clearly beneficial for customers under a real options analysis.[81] As such, a real options analysis is performed after a BCA, if appropriate, to assess any flexibility designed into a deployment plan for an investment. Real options analysis may be suitable for decisions involving infrastructure deployments that can be undertaken incrementally, for example, for a decision considering undertaking a large-scale network investment (e.g., an electricity delivery or communications network) versus pursuing a smaller network investment with a subsequent option to expand. A summary of the application of real options analysis is described below from the U.K. regulator, Ofgem.[82]

When does a real option approach to investment potentially provide a materially different answer to a NPV approach?

1. The investment needs to be partly irreversible (or sunk). If the cost of investment is fully recoverable, then there is no value in waiting to obtain new information and hence no option value.
2. There must be a significant element of uncertainty, which is related to both the volatility of the underlying asset and the time before we have to make a decision (e.g. exercise the option). The greater the uncertainty the greater the value of managerial flexibility in responding to new information.
3. There must be investment opportunities which provide management with flexibility to respond to the new information. For example, real option analysis is valuable where we have the option to phase the investment (expansion options) or to delay the investment (a deferral option).
4. The investment decision should be relatively marginal, i.e. the smaller the NPV value, the greater the option value. In other words, if the project NPV is high, then the option to invest (say) is always likely to be exercised and the component of the project's value which is represented by the option is relatively minor. Conversely, if the NPV is extremely negative, no amount of optionality can rescue the project.

UK Ofgem, Real Options and Investment Decision Making, page 8, March 2012

3.4.3 Other Considerations

A common concern is that DER integration will become a justification for grid investments that would otherwise just be done in the course of business, as described in Category 1 in the cost-effectiveness framework (Table 1 above). It is important to clearly denote grid modernization investments into each of the relevant categories 3 & 4. This will allow further evaluation of investments that are primarily geared at DER integration or DER utilization but may also provide synergistic benefits related to reliability, resiliency and operational efficiency. It is also important to clearly identify core components of grid modernization, as those are evaluated differently. By parsing investments into each of these categories, it is easier to assess reasonableness and apply methods to determine better value for customers through more flexible deployments. This framework will help align investments with needs and customer value while increasing the ability to evaluate these complex investments.

Additionally, emerging best practices related to assessing grid modernization investments based on several states' direction include the following guiding principles[83]:

- Transparency of planning and evaluation assumptions, perspectives considered, sources, and methodologies;
- Consider full-life-of-the-investment analysis, associated risks including sensitivity analysis on key assumptions;
- Assess grid modernization investments in comparison to a reasonable traditional or "business-as-usual" case and alternative flexible deployment approaches;
- Accommodate assessment of a modular approach that includes a bundle of technology solutions, rather than individual investments;
- Strive to improve the locational and temporal granularity of the grid need to support the valuation of distribution benefit and cost components and improve power flow modeling results;
- Allow for judgment, such that if investments do not pass cost tests based on included quantified benefits, a qualitative assessment of non-quantified benefits may be appropriate to inform approval;
- Consideration of potential synergies and economies between grid investments and various distributed energy resources; and
- Balance the interest in pursuing societal benefits of DERs through proactive grid modernization with customer affordability, as many benefits do not directly reflect in customer's bills.

4 APPLYING DECISION GUIDE

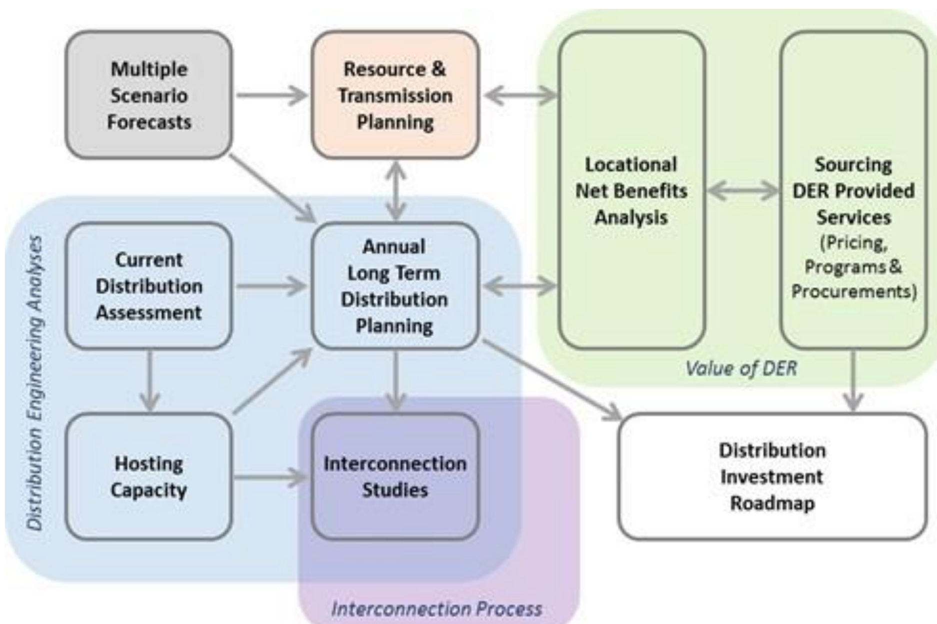
This chapter applies the decision framework to priority areas identified by the Steering Team to illustrate the use of Volumes I, II and III to support decision making. These examples are also ordered based on a logical sequence that also highlights any interdependencies that exists between several of these examples.

4.1 INTEGRATED DISTRIBUTION PLANNING

4.1.1 Description

For context, the functions in Volume I and the technology categories described in this report are mapped to an overall planning process. An Integrated Distribution Planning (IDP) framework[84] as discussed in several states includes the functional components illustrated in Figure 16 below.

Figure 16: Integrated Distribution Planning



<u>Multiple DER and Load Scenario Forecasts</u>

The uncertainty of the types, amount, and pace of DER expansion make singular deterministic forecasts ineffective for long-term distribution planning. Also, the changing nature of customer demand and related net demand requires more granularity than has been required in the past. Additionally, the use of multiple DER growth and energy demand scenarios is recognized as beneficial. The analysis is used to inform resource and long-term planning at both the transmission and distribution system levels.

Current Distribution System Assessment

An assessment of current feeder and substation reliability, condition of grid assets, asset loading and operations is needed, along with a comparative assessment of current operating conditions against prior forecasts of load and DER adoption. The following technology categories map to this functional area; Power Flow Analysis, Power Quality Analysis and Fault Analysis.

Hosting capacity

Hosting capacity methods[85] quantify the engineering factors that increasing DER penetration introduces on the grid within three principal constraints: 1) thermal, 2) voltage/power quality and 3) protection limits. These methods can be applied to interconnection studies and long-term distribution planning.

Interconnection Studies and Procedures

Interconnection engineering studies assess the potential positive or negative impact that a proposed DER will have on the distribution system. The process starts with an interconnection application through an analysis of the interconnection, and ultimately to a decision to approve, disapprove, or require upgrades to allow interconnection based on the results of a study.

Annual Long-term Distribution Planning

The annual distribution planning effort involves two general efforts: 1) multiple DER and load forecast scenario-based studies of distribution grid impacts leveraging a combination of the tools above to identify “grid needs” and 2) a solutions assessment, including potential operational changes to system configuration, needed infrastructure replacement, upgrades and modernization investments and potential for non-wires alternatives.

Integrated Resource, Transmission and Distribution Planning

At high levels of DER adoption, the net load characteristics on the distribution system can have material impact on the transmission system and bulk power system operation.[86] Today, distribution planning is typically done outside the context of integrated resource planning and transmission planning. To the extent DERs are considered in resource and transmission planning, it is essential to align those DER growth patterns, timing and net load shape assumptions and plans with those used for distribution planning. Over the next five-years (identified as the scope of this volume), an integrated transmission and distribution planning tool is not expected to be available. Instead, an iterative process between resource, transmission and distribution planning is beginning to be employed.

Locational Net Benefits Analysis

The value of DERs on the distribution system is locational in nature associated with a distribution substation, an individual feeder, a section of a feeder, or a combination of these components. The distribution system planning analyses, described above, identify incremental infrastructure or operational requirements (grid needs) and related potential infrastructure investments. The cost estimates of these investments form the potential value that may be avoided by sourcing services from qualified DERs, as well as optimizing the location of DERs on the distribution system.

4.1.2 Decision Considerations

4.1.2.1 Design Considerations

Conversations with sponsoring Commissions have led to the identification of several key attributes within integrated distribution planning that should be considered:

Transparent planning process

Given the diversity of customer needs, distribution circuit configurations and technological advancements, planning becomes more comprehensive and multidisciplinary with a wider and more complex range of engineering and economic valuation issues. Stakeholder participation and increased transparency becomes an important part of the distribution planning process, especially to enable participation by DER service providers and other third parties. This includes relevant data sharing in the annual planning process as appropriate. There is a tradeoff on the level of transparency, stakeholder involvement and process efficiency that will need to be addressed. One example is the California Distribution Planning Advisory Group (DPAG) concept that includes an Independent Professional Engineer (IPE) as part of a streamlined stakeholder review.

Identifying optimal locations for DERs

Annual distribution system planning analyses identify incremental infrastructure or operational requirements by location and related potential infrastructure investments. The cost estimates of these investments form the potential value (avoided cost of “wires” solutions) that may be met by sourcing services from qualified DERs as non-wires alternatives. This locational value assessment of avoided costs may inform DER incentive changes to optimize the location of DERs on the distribution system to mitigate/avoid impacts. The objective is to achieve net positive value (net of costs to implement the DER sourcing) from DER integration for all utility customers. These net values may also include avoided or deferred utility capital spent on wholesale energy and capacity, transmission upgrades and avoided operational expenses that are system-wide and not necessarily locational. There may also be environmental and customer benefits that are added to the DER value stack as identified in Figure .

Data for advanced forecasting and planning

Advanced forecasting and planning require the use and understanding of a utility’s traditional annual distribution planning process as well as the development of scenario-driven planning analysis. As the planning process begins to involve additional stakeholder engagement, additional bottom-up forecast data is necessary. Finally, as DER adoption and load forecasting become increasingly location-specific, more granular, circuit-level data will be needed, including 3rd party developer information.

Overall, advanced forecasting and planning will require the following types of data: customer data, circuit-level data, DER market adoption and performance data, and data on grid conditions (state information). Given the rate of DER technological advancement scenario analysis is necessary for annual long-term planning (typically 10-years) irrespective of whether material levels of DER adoption have occurred.

As processes for resource planning, distribution planning, and transmission planning become more integrated and aligned, consistent data and planning assumptions are necessary across all processes.

4.1.2.2 Enabling Technology

While most distribution system analysis tools have software modules with the capability to conduct basic distribution engineering studies and time-series simulations with the integration of DERs, notable gaps exist in the ability to conduct these advanced engineering optimization studies, and to reconcile these with hosting capacity analyses in an automated fashion. A significant challenge is the ability of a single solution or tool to address the full range of issues (e.g., voltage, thermal and protection issues) that arise from DER interconnection due to the highly location-specific value of DERs. However, it may be that the most cost-efficient and accurate solution lies with a group of loosely coupled software tools (e.g., CYME, LoadSEER, PowerWorld, etc.) used jointly. These tools will also require detailed, accurate network models to reflect the system at the appropriate point in time and more granular forecasts of the 10-year load shape changes due to DER load shaping expectations. Optimizations could be required at a more local, granular level and/or a system-wide level. The software tools should be capable of simultaneously processing both system level and local level optimizations. DER impact evaluation tools are considered to be in the operational demonstration stage.

4.1.2.3 Implementation Considerations

<u>Understanding and communicating utility annual distribution planning</u>

Historically, distribution planning is done primarily by the utility, without much transparency or opportunity for stakeholder engagement. However, distribution investments may represent a significant portion of a utility's capital expenditures. Utilities can improve communication regarding planning assumptions, methodology and review of planning results with regulators and stakeholders. Similarly, regulators play an important role in articulating policy objectives for distribution planning and oversight of the planning process.

<u>Locational Benefits Analysis</u>

State regulators should identify the methods to be used to determine the benefit associated with each value component that will be considered. For example, New York incorporated benefit-cost methodologies for each value component into a benefit-cost analysis handbook[87]. A locational benefits implementation roadmap should be developed that identifies which of the value components from a list such as in Table 2 may be evaluated in the near-term ("walk") to start, in the intermediate term ("jog") and in the longer term ("run"). Such a roadmap will be determined by the availability of accepted methodology to value a potential benefit and the related valuation tools/market mechanism. Some values are based on avoided costs that are determined in a planning process, others are determined through a market mechanism or administratively set. A logical sequence can be constructed by applying Pareto approach to achieve the largest net benefits first and then the remaining in descending order. Not all benefit components will be net beneficial as the gross value may be less than the cost to capture the benefit. [88]

A logical sequence can be constructed by applying Pareto (80/20) approach to achieve the largest net benefits first, and then the remaining in descending order. Not all benefit components will be net beneficial as the gross value may be less than the cost to capture the benefit.

A benefits roadmap should also identify specific gaps regarding the necessary prerequisites to value a component including the implication of simplistic econometric approaches. An evolution of the scope of benefits that may be included in the locational benefits analysis may be dependent on changes to electrical standards, the acceptance of standardized net benefits methods, commercial analytic tools, data availability and integration with wholesale and transmission planning. The locational benefits roadmap described above should also include a pathway for greater locational and temporal granularity in relation to the various value components that considers the trade-off between potential increase in economic optimization and the related increase in operational complexity and associate risk. This aspect of the roadmap should similarly identify the prerequisites, existing gaps and recommended steps necessary to implement this locational benefits roadmap.

4.2 SITUATIONAL AWARENESS

4.2.1 Description

The analog-to-digital transformation of the distribution grid involves a much greater awareness of the current grid configuration, asset information and condition, power flows and events to operate the distribution grid reliably, safely and efficiently. As defined in Modern Distribution Grid Volume I, situational awareness involves operational visibility into physical variables, events and forecasting for all grid conditions that may need to be addressed, normal operation states, criteria violations, equipment failures, customer outages and cybersecurity events.[89] Situational awareness is also required to operate a grid reliably with a high penetration of DER and optimize DER provided services. This includes visibility of the operation of interconnected DERs.

In the area of sensing, measurement and data acquisition, key issues are:

- Observability and system state – key concepts that can be used to guide the design of sensor systems for physical systems with topological structure and system dynamics
- Sensing and measurement – determination of quantities to be sensed, type and location of sensors, and resulting signal characteristics

- Data acquisition – collection of sensor data, sensor data transport
- Sensor network architecture – elements, structure, and external properties of sensor networks
- Communications to support grid sensor networks

4.2.2 Decision Considerations

4.2.2.1 Architectural & Design Considerations[90,91]

A key function within situational awareness is grid state determination. State is the minimum set of values (state variables) that describe the instantaneous condition of a dynamic system. Grid state is an essential function to managing transmission systems and increasingly identified as a core function for distribution systems to actively manage reliability and efficiency, especially with material levels of DER.

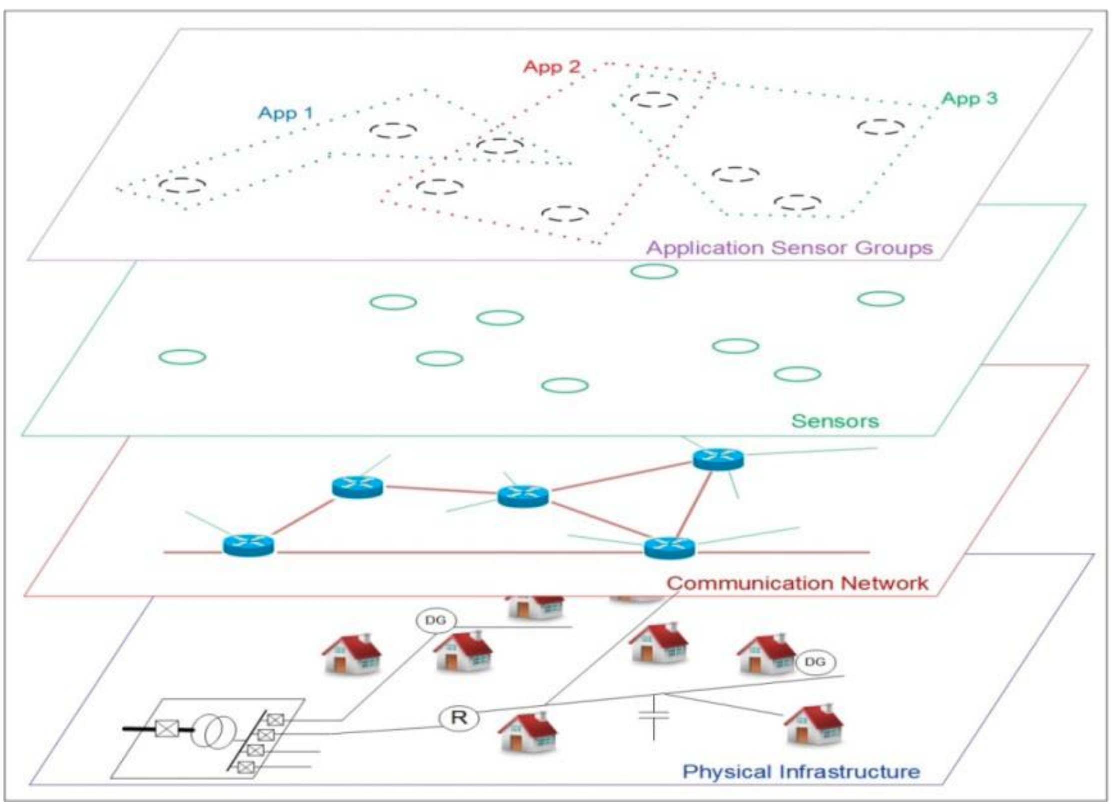
For electric transmission systems with known or assumed models, a snapshot-based process using a set of sparse state variable measurements, a system model, and a mathematically intense solution method performs what is widely known as transmission state estimation. However, state estimation of this type is not useful for distribution grids, due to inherent topological complexities and the fact that feeders are generally unbalanced. State measurement instead of state estimation for distribution is preferred if necessary sensing information is available; however, today this information is typically not available. The following seven grid state classes are comprised in situational awareness.

- Power state – electrical operating parameters, such as voltages, currents, real and reactive power flows. Information is also needed on availability and performance of DERs, such as storage charge state, DER available and forecast capacity.
- Power quality state – power quality measurements are the manifestation of underlying quality state. Quality issues include voltage deviations and harmonic distortion which are generically difficult to value.
- Thermal state – thermal state is reflected in temperatures, for which we keep two types: hotspots (for both devices and circuits) and temperature profiles or distributions (for circuits). Temperature can be measured directly in many cases, although with some devices, actual hotspots may be internal and not easily accessible to instrumentation).
- Device State – consists of service state (in service, out of service, failed), setting or position (open, closed), loadings, and device parametrics (impedance, dynamic rating).
- Circuit State – consists of service state (in or out of service, failed), loading, and parametrics (circuit segment impedance, dynamic rating). Circuit impedances are distributed parameters, but may be determined on a per segment basis.
- Asset Health State – consists of two aspects: condition (present health state) of devices and circuits, and accumulated stress that accelerate failure and degrade performance and can be treated through component loss of life and estimated time to failure.
- Market State – increasingly important as markets become elements of grid control with the inclusion of DER provided services.

The need to monitor grid state for control purposes leads to the need for observability and therefore sensing and measurement. Grid sensors have generally been associated with specific systems or applications and have been deployed as adjuncts to those systems or applications. Consequently, they have not generally been treated as network structures with architecture and relevant standards. Sensor system architecture is a subset of grid architecture that cuts across electric infrastructure, ICT[1] networks, control and coordination structures, in addition to data management structures and starts with a consideration of requirements as driven by emerging trends and public policy, resulting in a set of desired grid qualities and necessary grid properties.[2]

Grid sensor architecture must consider the underlying physical system structure, the relationship to communications network structure, and the relationship or relationships to applications that make use of sensor data. It is helpful to view grid sensor and measurement systems abstractly in a layer format, as shown in Figure 17 below. As with other grid architecture work, these structures should be considered together, especially in the case where new communications networking is being developed along with the other structures, as would be the case in much distribution grid modernization. Existing legacy components and structures must be viewed as constraints as well as assets in the sensor architecture development and subsequent design processes.

Figure 17: Sensor Architecture Abstraction Layer Model



These considerations and the increasing complexity of modern power grids lead to the conclusion that the electric utility engaged in grid modernization must consider creating an observability strategy to guide the implementation of grid and DER sensing for modern grid operation.

4.2.2.2 Enabling Technology

Operating a more advanced grid will require a wide variety of new analytics and simulation solutions and will rely on robust and secure communications to bring situational awareness of the distribution grid much closer to real time. Section 2.2 of Volume II assesses the technologies required by the functional elements of Distribution Grid Operations described in Volume I.[92] More specific to improving situational awareness for a future generation grid system are aspects of operational analytics and sensing and measurement. Operational analytics transform historical and real-time data from the electrical grid into actionable insights for improving operational reliability, awareness and efficiencies. Sensing allows for observation of the distribution grid and DER, as well as environmental factors that influence DER performance and grid operations and sensing for cyber and physical security. Sufficient sensing and data collection can help assemble an adequate view of the grid state.

Software-based electrical network connectivity models are in early commercial deployment. However, the key challenge to real-time connectivity models is maintaining the availability of accurate and “clean” data. Typical approaches to GIS/network model data cleanup do not ensure ongoing data integrity because they do not address the underlying volatility of an operational grid. Real-time connectivity models are therefore in operational demonstrations.

Distribution state estimation for real-time use in distribution systems with high levels of DER is in initial operational demonstrations. The unique features of the distribution grid (i.e., a significant number of nodes, radial topology, unbalanced phases, etc.) create challenges that are not faced on transmission systems. Problems can also arise if inputs to the state estimator consist of a combination of pseudo data and real measurements, which vary temporally and spatially, or if the measured objects delivered from different sources are different from each other in terms of voltage or power. As such, classic state estimation methods for transmission work poorly on distribution feeders.

4.2.2.3 Implementation Considerations[93,94,95]

State Determination

Determination of grid state is a key modern grid process. Due to the complexity of distribution grids and the cost of sensor installation, implementing proper grid state determination is not a trivial exercise. For each feeder, we must create a grid sensing strategy that, when aggregated across the whole system, results in a sensor network design for the entire grid. The strategy is necessary to ensure that sufficient measurement is done to provide grid state determination, while minimizing the total cost of the sensor network (including not material costs but also installation and service labor).

Observability for distribution grids is fundamentally a more difficult issue than for transmission for all but the simplest radial systems. Complicating factors include feeder branches and laterals, unbalanced circuits, poorly documented circuits, large numbers of attached loads and devices and, in the case of feeders with inter-ties, time-varying circuit topology. In general, circuit topology and device electrical connectivity may be poorly (incompletely or inaccurately or both) known. As described earlier, these issues make state estimation more difficult for distribution than for transmission systems, so it is necessary to rely more upon state measurement and less on estimation.

Distribution grids present special problems in terms of topological state. Such state information is crucial because it is the context in which grid data, events and control commands must be interpreted. The problems arise because unlike transmission grids, "as-built" topology for distribution grids is often not completely or accurately known. In addition, distribution grid topology can be dynamic, such as in the cases where feeders are partially meshed or are tied to other feeders for reliability reasons. In such cases, circuit switches, sectionalizers, or reclosers may be operated to change the topology and such changes can be frequent. Consequently, power flows in a given circuit section can reverse, as can voltage rise and drop. As DERs integrate on distribution feeders, power flow reversals can occur, impacting protection schemes and volt-var regulation.

Due to grid switching, a feeder section may "belong" to more than one feeder or substation. This raises several issues: how to obtain real time circuit topology, how to represent power state for such sections (since power state must refer to circuit topology), and how to handle distributed sensor data acquisition (which of the several distributed DCE's should collect the data from a section that can belong to more than one substation, for example).

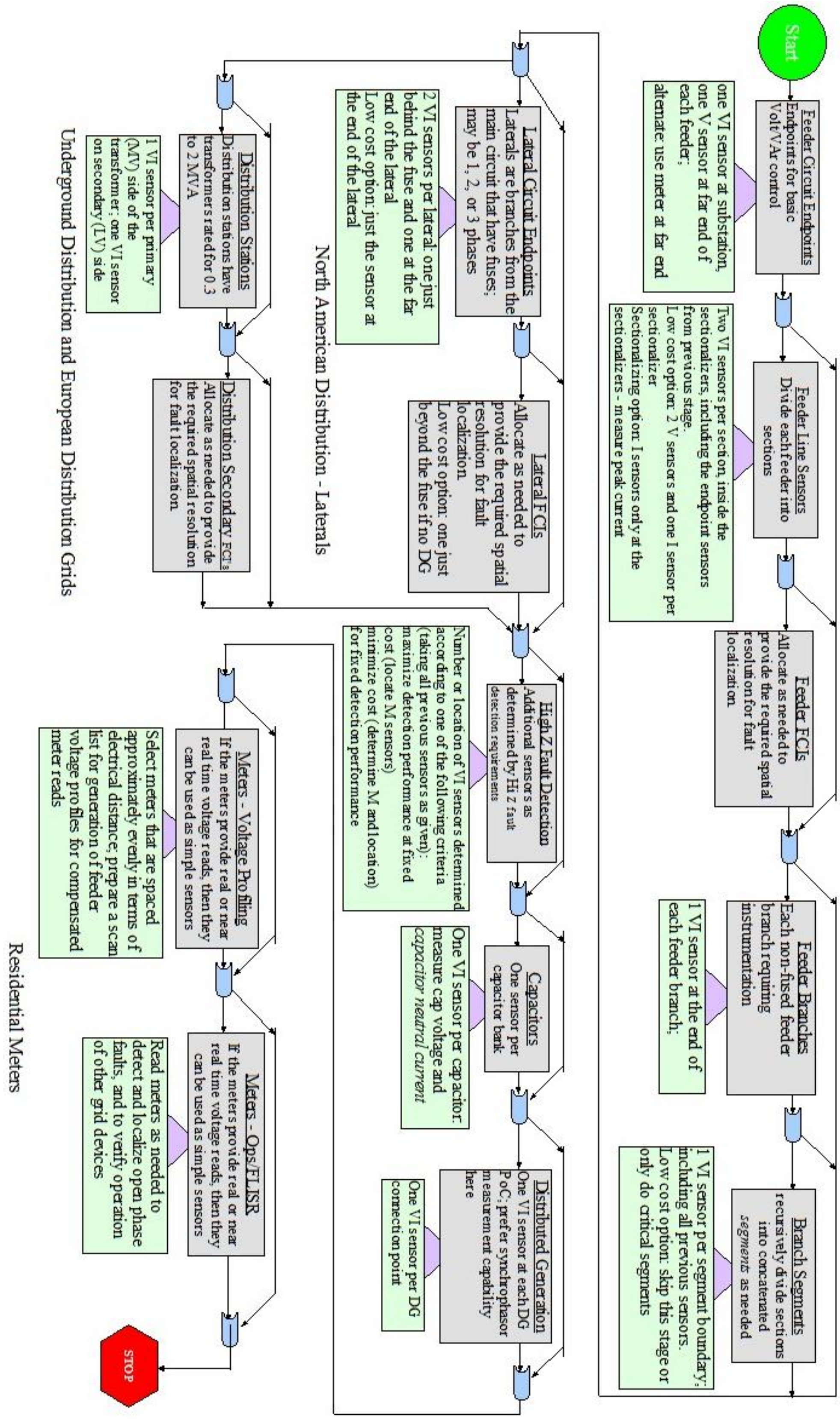
Sensor Network

The sensor network architectural view treats sensors and the communication network as an integrated structure. Various services are inserted into this structure and, where possible, the structure employs advanced communication protocols to provide capabilities often either built into siloed applications or supplied via an abstraction layer software platform. Data can flow from sensors in continual streams to any authorized recipient application; in fact, multiple devices or applications can receive such streams from the same sensor– applications merely need to be connected to the network at some point – in simple terms, "plug and play". In that sense, the sensor network can operate as a publish-and-subscribe data system.

For sensors that do not have streaming capability, data acquisition engines may be attached to the edge of the sensor network to perform more traditional polling and other modes of data collection. Hence both legacy SCADA and more distributed data collection can coexist on the same network. Similarly, distributed database data store nodes may be attached to the sensor network, or data may be accumulated into individual applications. Each application may associate sensors as needed, providing low-latency grid data access with great flexibility. Various services can be integrated into the sensor network via attached servers or through integration into network management systems. These include standard network management and security functions as well as grid-specific capabilities such as sensor meta-data management, IEC 61850 CIM interface services, and grid topology/connectivity.

Leveraging this type of sensor network architecture, the various types of sensors to address the several classes of grid state should be allocated across a distribution to establish necessary observability. Figure 18 below shows a template for a distribution feeder sensor allocation strategy:

Figure 18: Distribution Feeder Sensor Allocation Strategy Template



DER operational information[96]

A more distributed, less predictable electricity system raises the standard regarding data necessary for transmission and distribution grid operators to meet their responsibilities. Today, operators lack consistent, reliable DER-related data in their respective balancing areas and service territories. These grid operators should have access to basic, static DER data series in their service territories. Location, size and technological capabilities are examples of critical, reliable data operators need to formulate a strategy to manage an increasingly distributed electricity system. A general operational data framework should be developed, where increasingly comprehensive operational data from the distribution system is provided as DER adoption reach different thresholds. This framework should be flexible enough to accommodate different state policies.

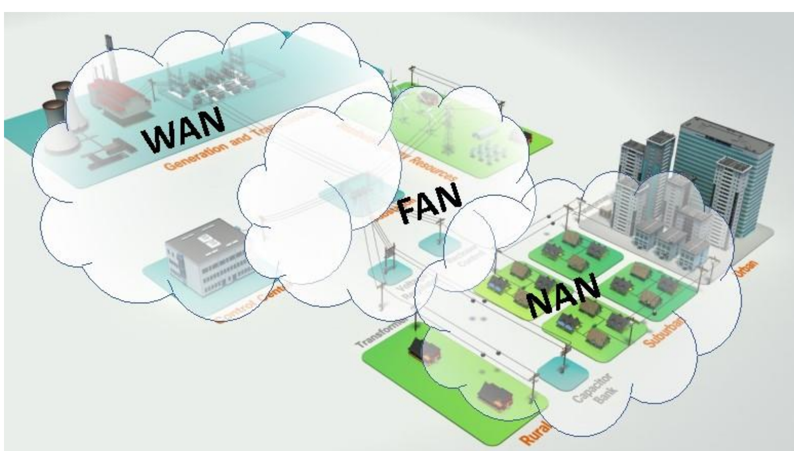
Regulators and stakeholders should be engaged to address four initial areas: 1) identifying what type of DER data is needed and for what purpose; 2) identify required accessibility for different data; 3) identify the availability of required types of data by all relevant parties; and 4) initiating consistent DER provider reporting information within a jurisdiction.[97]

4.3 OPERATIONAL COMMUNICATION NETWORKS

4.3.1 Description

An Operational Communication Network is the integration of multiple physical communication technologies – a network of networks – that may include both private infrastructure as well as Telecommunication Service Provider (SP) infrastructure. An Operational Communication Network can be grouped into a hierarchical system of three general parts ("tiers"): wide area network (WAN), field area network (FAN) and neighborhood area network (NAN) with functions as described in Volume II, Section 2.2.4.[98]

Figure 19: Illustration of Operational Communication Network Tiers



Each tier offers services that can be tailored to specific requirements of systems, devices and applications such as bandwidth, latency, resilience and security. Each tier employs multiple communication infrastructure or media such as optical fiber, wireline, or one or more of the many wireless radio technologies, as may be available within existing infrastructure or suitable to specific locations and requirements.[99]

Relative to other investments in grid modernization, operational communication networks represent the fundamental enabling technology required by all the capabilities described in Modern Distribution Grid, Volume I. Proper architecture, design and implementation will also lower the incremental cost of adding capabilities as required to address the continued evolution of DERs.

4.3.2 Decision Considerations

Operational Network Design is a large and complex undertaking that is the subject of entire university courses of study.[100] Design considerations assume the well-established process of: 1) identifying the requirements; 2) matching requirements against proven architectures and using relevant aspects of proven architectures to inform the approach to development of an architecture; and 3) development of a specific architecture network design and system project plan that addresses not only initial implementation but also lifecycle management of the system.

Past industry practice and regulatory management has been to treat projects monolithically, specifying operational communication networks adequate to specific project needs with minimal (if any) consideration for enabling future projects. Regulatory requirements for specific project applications, particularly with AMI systems, have encouraged communications systems specific to each project. The result is multiple siloed communication systems of different technology generations, each requiring separate security, maintenance and management.

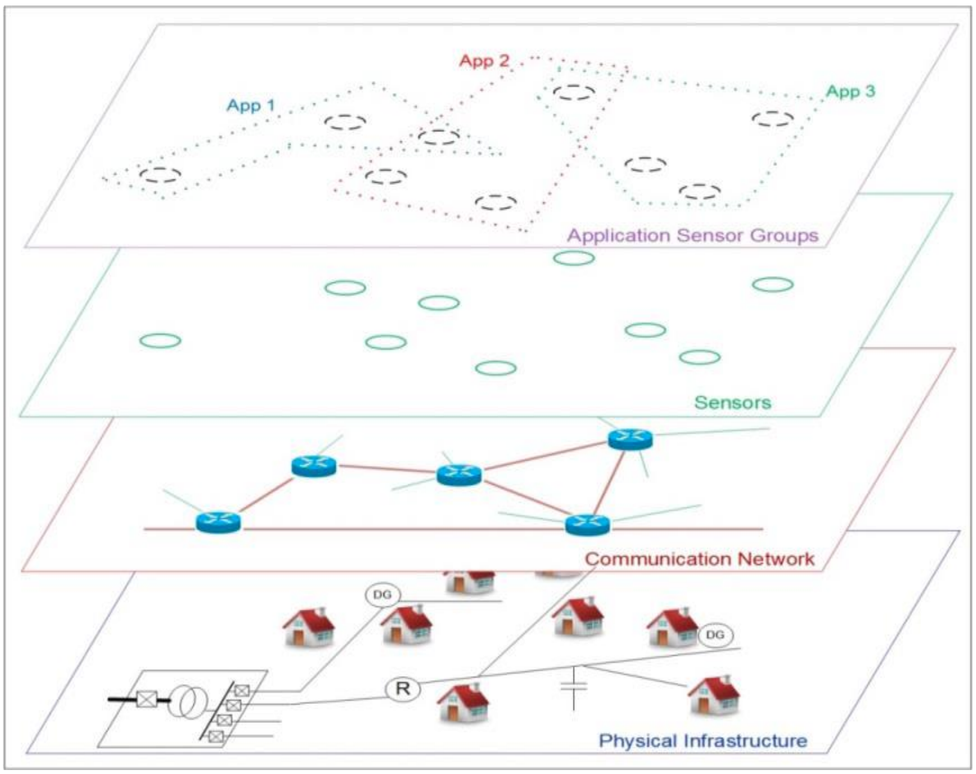
A major benefit of an architectural approach to distribution grid modernization is the ability to place individual projects into context and where requirements overlap and where additional marginal cost in a multi-services network may be more than offset by sharing the operational communication network service across multiple projects and applications to create greater customer value. The resulting solution results in an optimized use of a core infrastructure that has lower overall costs to implement and maintain than building multiple siloed networks.

4.3.2.1 Architectural & Design Considerations

Operational communication networks for modern distribution grids have essential architectural and design considerations in several key areas. The starting point in developing an operational communications architecture is the identification of customer and policy objectives and infrastructure considerations over its anticipated lifecycle (e.g., 15+ year). This includes the related attributes that drive functional requirements to support substation and distribution automation, grid sensors, protection schemes, distributed device control, smart metering and integration and control of DERs.

It is also necessary to consider the connectivity required to obtain system data (e.g., sensor/measurement information, event alerts, device status, etc.), send control signals to grid devices, as well as other information to manage and secure a communication network.[101] This requires a multi-purpose operational communications platform that in simple terms, is "plug and play". A grid communications network needs to enable an interoperable publish-and-subscribe schema to enable streaming operational data to the various systems that need the same data but may have different latency requirements as illustrated in the Figure below.

Figure 20: Multi-services Operational Communications Architecture



For example, both legacy SCADA and more distributed data collection can coexist on the same network. Each application may subscribe to individual sensors or devices as needed, providing low-latency data/control transport with great flexibility. This type of schema requires standards-based network management and security functions as well as grid-specific capabilities such as sensor meta-data management, IEC 61850 CIM interface services, and grid topology/connectivity. Conversely, a voltage control application that accesses a smart meter in a traditional silo network structure sends a request to a meter data head end system (software and hardware that initiates and receives data from devices and may perform a limited amount of data validation before either making the data available for other systems), waits for the head end to query the meter via an AMI network, and waits until the head end provides a value back to the voltage control application via an enterprise wide area network after the meter responds. This type of scheme was prevalent in 2000's era single purpose network configurations and is no longer preferred. Several key attributes of multi-purpose operational networks need to be considered:

- **Security** – Both cyber and physical security vulnerabilities need to be assessed against potential risks, likelihood of occurrence, effective mitigations and operational and regulatory requirements.[102]

- **Interoperability** – The current or future need for interactions between systems. The potential economies of scale and reduced costs in in a multi-services communication system that leverage common infrastructure, management and security costs across multiple applications.

- **Network Management** – Every communication network requires management for establishing the configuration of devices, monitoring their operation, performing necessary maintenance and diagnosing and fixing any problems that arise.

- **Standards** – Relevant open international standards for the operational applications or processes, and consideration of whether the processes are new or mature.

To address these attributes, modern grid communications networks use the interoperable standard Internet Protocol (IP) suite (which does not mean using the internet itself, just the standard communication protocols) which is capable of providing both performance and service requirements. IP-based private networks leverage the telecommunications industry's robust development and enormous capital investment to create effective security technologies[103] and network management. Additionally, the emergent Wi-SUN Alliance field area network specification[104] is intended to enable the ability of communications system to be able to support multiple vendors' devices, such as distribution field automation and smart metering, to create the layered network structure above.

Performance requirements are also very important and must align to the functions and associated time dimensions being supported as illustrated in Figure 21 below. When coupled with the planning process overlay, this demonstrates the complexity of solution resolution. Several key aspects for design considerations are:

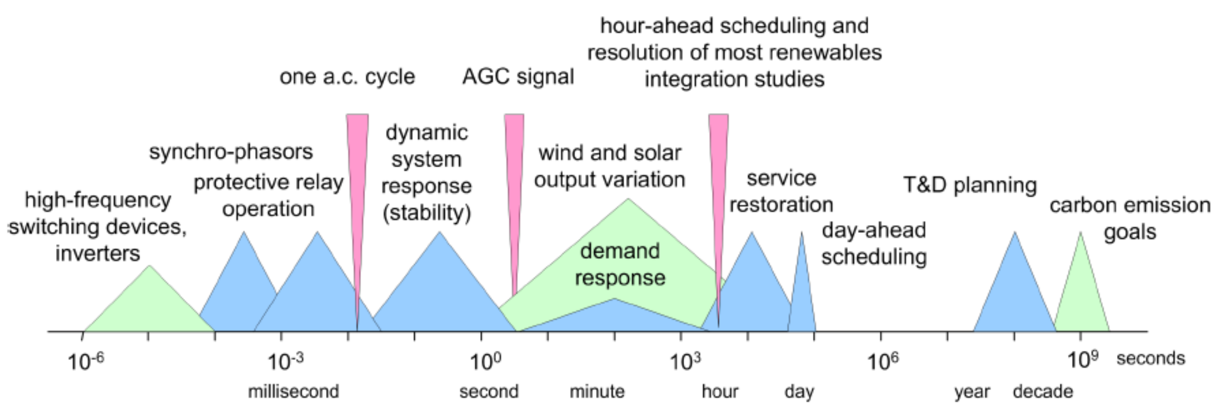
- **Bandwidth** – The instantaneous rate at which raw digital data is transferred through a communication channel. For distribution automation applications, typical minimum bandwidth requirements are 100kbps. In contrast, AMI data applications typically have minimum bandwidth requirements of 30kbps.

- **Throughput** - The amount of data that can be delivered error-free from end to end. This may be only a small fraction of the raw channel bandwidth.

- **Latency** – The time it takes a command, data, or a response message packet to traverse a communication channel. An Operational Communications Network is, at its core, an industrial control system with time critical elements. For distribution automation applications, typical maximum latency requirements are 100 milliseconds. In contrast, AMI billing applications typically have minimum latency requirements of 30 seconds.[105] The Figure 22 below summarizes typical bandwidth and latency requirements.

- **Reliability & Availability** – Operational network reliability refers to the ability to consistently perform according to its specifications. Availability is the percentage of time (per month or year) that the service works correctly. For distribution automation applications, typical minimum requirements are 99.99% (which means about one hour of downtime per year) because communication availability is critical to protection coordination and system restoration. In contrast, AMI billing applications typically have minimum reliability requirements of 99% (which means about 88 hours of downtime per year) because usage data is retained in the meter so that in the event of communication unavailability, that data can be retrieved later. Customer billing only requires a complete data set only once per month. This is to illustrate that multi-service operational communications need to address a wide range of uses and requirements.

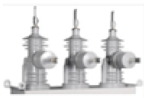
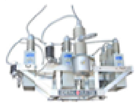
Figure 21: Grid Operational Time Periods



Source: CIEE/ A. von Meier

Figure 22 below highlights some common requirements for communications between devices and operational systems.

Figure 22: Typical Bandwidth & Latency Requirements

	Distribution Application	Bandwidth	Latency
	Advanced Smart Meters	10kbps	5 seconds
	Grid Sensor	10kbps	5 seconds
	Recloser/SCADA Devices	10kbps	100 milleseconds
	Capacitor Bank	10kbps	10 seconds
	DER <50kw	10kbps	5 seconds
	EV Charging	10kbps	10 seconds

<u>Further considerations to bandwidth and latency</u>

It is beyond the scope of this paper to present a detailed explanation of bandwidth and latency. There are many different types of data transmission: streaming data, where overall sustainable bits-per-second at a specific error rate is required; bursty data where a bundle of data needs to be delivered within a specified period, but that only occurs at intervals that are 10 times or more than the time it takes to deliver the data; and, sparse data, where the channel is busy less than 1% of the time. Bandwidth generally refers to the raw data rate of the communications channel. For a device, that's generally the data rate of the interface.

<u>Lifecycle Management</u>

For operational networks, lifecycle management must cover communications technology life cycles (about 10 years) that are independent of the evolution of the distribution grid and interconnected DERs. Because of the size and extent of electric power distribution grids, when widely deployed communication technologies reach end-of-life (i.e. end of sale and end of support), the abruptness of that transition relative to the timeframes for lifecycle management of distribution grid infrastructure presents a major challenge.

4.3.2.2 Enabling Technology

Volume II, 2.2.4, Communications Infrastructure, covers the full range technologies that support the functions required by a distribution grid, including legacy technologies, and detail their maturity assessment. Of these technologies, those typically considered for a modern grid include:

Wide Area Networks

MPLS is a mature packet-switching technology used in multiple industries. It is the core technology of telecommunication service provider networks and is increasingly being deployed for grid operational wide area networks between operating centers and substations where high performance, high bandwidth and low latency connectivity are needed.

Microwave Communications is in mature deployment for grid applications especially in areas where it is cost prohibitive to construct physical communications infrastructure. Microwave is commonly deployed for transmission and distribution substation communications to address high performance and low latency operational requirements such as protection and SCADA.

Satellite Communication is in mature deployment; however, important tradeoffs/limitations to note are high latency due to connectivity with satellites in geosynchronous equatorial orbit and recurring cost based on data usage. It is used for selective remote substation and metering uses.

Service Provider Mobile (SP LTE) services have been used as the WAN backhaul for many AMI deployments to-date as wells as an option for replacing paging services for direct load control programs. However, mobile services are not widely used in field automation given the availability, reliability and other performance requirements. This lower level of service is sufficient for routine meter data collection only.

Field Area Networks

WiMAX is a mature technology approaching obsolesce with limited adoption for grid communications. Deployments on the U.S distribution grid have been hampered by lack of licensed spectrum. It is no longer considered an acceptable grid solution.

Private LTE networks have been deployed in limited numbers and are in a stage of early commercial deployment. Private LTE networks can be used for supervision and communication with grid automation devices and NAN applications such as AMI.[106, 107, 108, 109, 110]

Paging Systems are obsolete. Most direct load control programs had been using paging systems since the 1980s and have recently been converting to mobile services or NAN connectivity.

Neighborhood Area Networks

RF Mesh networks have emerged as the leading technology for AMI and distribution automation deployments in North America. The tradeoffs are latency (data transmission timing) and bandwidth. This requires careful design to balance cost with the number of devices to manage the latency and bandwidth required for grid applications.

PLC is primarily used in areas inaccessible to RF. PLC is much more cost effective for European type distribution grids as they have much larger low voltage transformers serving 20 to as many as 150 residential customers.

4.3.2.3 Implementation Considerations

Implementation considerations address "how" operational communication networks are deployed, including considerations around scope, technology selection and integration of legacy systems, as well as "who" considerations that deal with the role of service providers, private infrastructure and ESOs.

<u>How</u>

Incremental vs system wide deployment: Deployment over a distribution grid service area is a huge undertaking that must be prioritized in a multi-year plan based on the highest needs and areas of the highest return based on the forecasts, engineering studies and cost-effectiveness analyses that have been done.

Regardless of the scope of deployment, critical head-end integration, network management and network security are required. These functions are usually consolidated in a Network Operations Center (NOC). Consideration should be given to co-locating the NOC with the Control Center for the distribution grid, as the first response to any grid anomaly or loss of telemetry will be to verify communication integrity.

With the establishment of the necessary head-end, FAN technologies can generally be deployed incrementally whether they are private or service provider technologies, or integrated systems using both. NAN deployment very much depends on local communication environments. RF mesh is widely used to address RF path issues with automatic rerouting around RF obstacles that are constantly changing due to vehicles, construction, interference and many other factors. Access points, concentrators and/or relays all are used to address communication path issues. They can be deployed as sparsely as possible to minimize cost at the expense of increased latency, or deployed in greater numbers to minimize the number of hops and consequently minimize latency.

During a multi-year roll-out, forecasts and priorities will be updated on a periodic basis along with analysis of any changes and opportunities brought about through technology or regulatory developments, including analysis of actual versus expected failure rates and analysis of security incidents.

Use of various technologies to achieve performance: Technology and vendor selection should be based on demonstration of the critical parameters of the planned project – generally bandwidth, latency, throughput, packet loss and error rates – and proven ability of the vendor(s) to complete the project. Marketing statements that cite raw bandwidth, channel capacity or other similar specifications have almost no relationship to real world throughput, which depends most heavily on error rates caused by the radio environment. There is no magic bullet for a difficult RF environment. No vendor or technology has a way to overcome the laws of physics. There is no substitute for an operational demonstration that exposes all aspects of a technology, including lifecycle management, logistics, QA and security processes to evaluation.

Legacy Considerations: The analyses of lifecycle management must be applied to the many generations of technology that can be found in operational communication networks. The electric power industry is the largest user of obsolete analog, TDM and frame relay technologies as described in Volume II.[111] Specific evaluation must be made of the costs and risks associated with managing multiple legacy technologies that are no longer under development and/or support, securing those communication technologies to ever increasing requirements, and maintaining a critical mass of technical skill as workers experienced with older technology retire.

<u>Who</u>

Telecommunications Service Providers (SP) Services: The question arises as to whether operational communication networks should simply be completely supplied by or outsourced to telecommunication service providers (SPs). SPs and grid operators do a lot of business together. Almost every operational network includes links provided by telecommunication service providers (SP) as well as private infrastructure. These may be MPLS services, carrier Ethernet, microwave, mobile data services or others that may also be implemented on private infrastructure. In each case the judgement must be made as to the suitability of the available service level agreement provisions to the cost and critical operational parameters required.

There are several aspects to the complex relationships between SPs and grid operators. It is every bit as important to verify actual throughput and latency with a SP communication service as it is with a private infrastructure deployment. In many cases, especially with mobile data, data must transit the SP control center before being routed to the distribution operations control center, adding undesirable latency that is sometimes overlooked.

Distribution grids additionally may span service territories of more than one SP, complicating business arrangements. Most distribution grids span or interconnect areas where no service is available. SP Service Level Agreements are "best efforts" determined by the technical architecture and implementation with no ability to prioritize or guarantee priority service in critical operational situations including disaster scenarios. Everyone is used to mobile "dead zones", dropped calls and reception that differs by walking around – these are substantial deficiencies to immobile grid automation devices.

Both SP and private implementations are subject to technology lifecycle time horizons, but control of end of life and transition planning are key differences – the utility having no control over a SP decision to end service, such as recently occurred with 2G. Additionally, SPs' primary business model is services revenue per unit or end device, a model that attaches monthly fees to individual utility connection points.

ESOs: At present, two different models for operational communication systems are being discussed – one is the conventional operational communication network and the other is a non-utility network that may use any of various communication service provider data transport mechanisms, including ordinary internet services and cellular services. In this case, the DER has *electrical* connectivity to the grid, but not *communication* connectivity (except in a very indirect manner via the ESO).

A question is whether distribution utilities can avoid investment in new distribution sensing and communications systems by relying upon third parties and the DER they may own and/or operate to provide both grid sensing and grid communications. This question was discussed at the California Public Utilities Commission (CPUC) workshop on January 24, 2017. As explained by SolarCity, their aggregation control system structure is in addition to and complementary to those structures needed by the distribution operator as it serves a different purpose. As such, it does not eliminate the need for the distribution operator to have field communication networks as discussed earlier.

4.4 VOLT-VAR MANAGEMENT W/SMART INVERTERS

4.4.1 Description

Steady-state voltage management (generally >60 sec), includes voltage limit violation relief, reducing voltage variability, and compensating reactive power.[112] If the voltage is maintained within ANSI C84.1 Range A (incorporated in most states' service quality requirements), no changes to voltage are required. Related functionality includes power quality management to ensure proper power form, including mitigating voltage transients and waveform distortions (e.g., voltage sags, surges and harmonic distortion as well as momentary outages).[113] An additional function involves conservation voltage reduction (CVR), where overall energy consumption is reduced by decreasing end-use voltage given that many electrical devices operate more efficiently with reduced voltage. A holistic Volt-var management system may include traditional grid devices as well as grid power electronic flow controllers and smart inverters integrated with distributed resources.

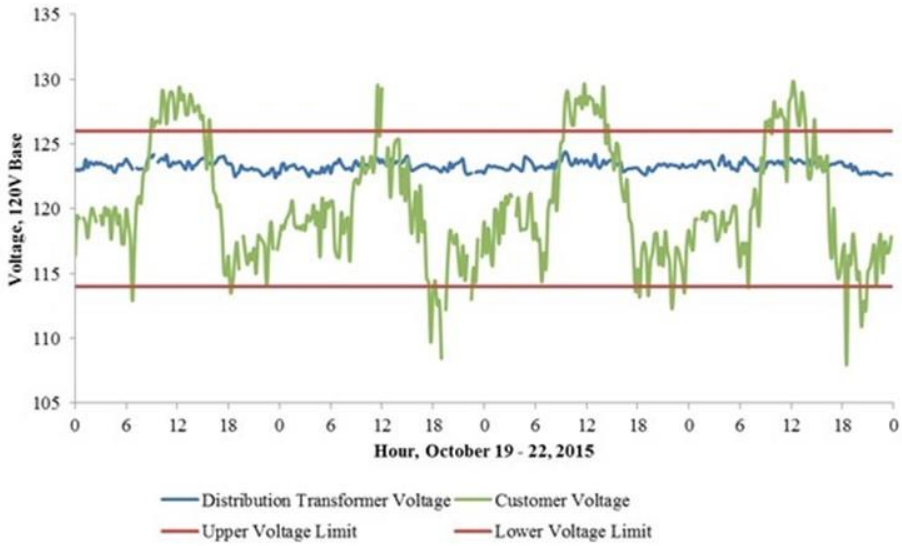
4.4.2 Decision Considerations

4.4.2.1 Design Considerations

A key design consideration is the need for any incremental voltage and/or reactive power management based on engineering planning studies. Voltage is managed today through a combination of reconductoring, increasing transformer size, capacitor banks, and load tap changer settings. These approaches have historically been employed to address issues that changes in load can cause. As such, most distribution circuits do not need additional management functionality until variable DER, such as solar PV, reaches a certain level which causes voltage violations of the ANSI standard. Violations can cause lights to flicker or damage customer equipment.

Solar PV creates voltage rise and drops as well as transient variability since often there isn't diversity (aggregated smoothing) that is typical of load. Slow variability (voltage rises and drops) isn't really an issue in itself, but it can increase wear and tear on other regulating equipment (and make some voltage regulators less effective). However, fast variability (transients) is especially problematic. Figure below illustrates this issue created by rooftop solar PV on a distribution circuit and customer side of service transformer in Hawaii.

Figure 23: Hawaii Distribution Circuit Voltage



Source: Hawaiian Electric Companies

Standard inverter functions include, for example, safety functions such a disconnecting on power outage as detected by loss of line voltage as required under existing IEEE 1547 DER interconnection standard.[114] This function could be triggered by transient voltage drops due to area grid disturbances. A problem is that large scale simultaneous disconnection of distributed solar inverters results in the full gross load appearing on the grid which can exacerbate grid issues that originally caused the disturbance. Additionally, absent visibility into PV production, this hidden load can impact operations and reliability.

IEEE has been developing a revision to the 1547 standard including voltage and frequency ride through settings to allow more solar PV to stay connected during short duration contingency events and implementation autonomous and controllable functions needed to ensure service quality. The final revised IEEE 1547 requirements (expected in 2017) include both autonomous functions (e.g., Volt-Watt, Volt-var and frequency-Watt) and requirement to communicate over at least one of several standard protocols. These new functions can be used for most conceivable regulation cases. In fact, for most locations and uses, the autonomous inverter functions should be sufficient in coordination with the grid side devices to address service quality needs. However, as penetration levels increase, other mitigation technologies may be required.

One design consideration is how to integrate the new autonomous and/or controllable functions into existing distribution Volt-var management systems and related interconnection requirements. Additionally, not all existing inverters are "smart" and therefore may not be able to be upgraded with the new 1547 functionality. The number of these non-smart inverters may be quite large where significant adoption of solar PV has occurred over this decade. Additionally, if smart inverter upgrades are not required for these existing inverters, the benefits from new smart inverters will be substantially less. An associated challenge for regulators and grid planning is that there are typically no single accessible data repositories (each ESO/inverter manufacturer maintains their own proprietary database) on inverter asset information for all inverters connected to the grid. For example, information including device type, date installed, functionality, computer models, software version and upgradability, and communication capability that would be helpful to understand the potential to leverage inverters are not easily accessed.

Another important consideration is that there are no cybersecurity standards applied or adhered to by smart inverter manufacturers or DER providers in the device manufacture or system integration and operating systems that interface with the grid. This is a significant and growing gap in the grid cyber defenses as inverter based DER (solar PV and battery storage) increase.

Additionally, it is not yet clear the number of controllable inverters that may be needed to mitigate specific issues beyond those addressable through autonomous operation. Also, grid side power electronics (similar to inverters) can also address the more complex issues requiring controllability and may be simpler and less costly to implement and operate. Given the mix of older non-upgradable and smart inverters, it will likely be necessary for grid side power flow controllers to augment the smart inverter functionality as part of a holistic voltage management system.

4.4.2.2 Enabling Technology

Volt-var management application, as described in Volume II, includes analytic models to determine which grid and/or inverter devices to adjust and by how much for optimal performance. The software system, in a centralized or decentralized arrangement, sends control setting adjustments to devices such as load tap changers, voltage regulators, capacitor banks, power flow controllers and smart inverters.

Integrated Volt-var optimization (IVVO) systems have not been widely deployed as traditional voltage management techniques can be used to achieve efficiency gains from conservation voltage reduction (CVR). However, increasingly the driver for the installation of IVVO systems is often the increasing levels of variable DERs that impact voltage quality and require more sophisticated approaches to manage voltage. Smart inverter technology exists, but have not yet been used operationally within an IVVO system. Current operational demonstrations are testing the new IEEE 1547 functionality. It is expected that upon final approval of the revised IEEE 1547 standard, Underwriters Laboratory (UL) will conduct testing for certification within a year, suggesting the implementation of advanced inverter functionality may begin by 2019. In California, a smaller subset of autonomous functions is being required starting September 8, 2017 with the availability of UL 1741-SA test standard.

4.4.2.3 Implementation Considerations

For those systems experiencing increasing distributed solar PV adoption, a multi-step approach should be used to address impacts on distribution systems. It is no longer a question of whether distributed solar PV creates voltage issues on the grid. The question is what to do about it in a way that is appropriately responsive to the need and is cost effective. There are several levels of performance by inverters that can be employed to mitigate issues as part of an overall Volt-var management system.

Walk: Autonomous voltage control & reliability functions

At higher levels of distributed solar PV, the majority of hosting capacity and service quality issues stem from voltage quality violations. An approach is to leverage smart inverters' capability (under revised IEEE 1547 standard) to operate autonomously. As an initial step, the inverter can be set to operate autonomously based on parameters provided through interconnection requirements based on results from interconnection studies and/or distribution planning process.

Jog: Periodic Inverter set-point changes for autonomous operation

As may be needed at higher DER levels, periodic adjustments to inverter settings as part of an overall Volt-var management can be made. If set-point changes are desired they can be sent from a distribution operator directly to the inverter or through an aggregators' links to the inverters. This approach would involve periodic updates to the functions based on annual or operational planning or interconnection studies. However, these adjustments would not be expected to be frequent given the inherent limitation of the flash memory in inverters to degrade on frequent rewriting of software code.

Run: Volt-var management services

Expand the use of inverters for system benefit for incremental performance beyond walk and jog functionality through integration with a grid operator's DERMS/IVVO system. For example, if the utility needs more dynamic operation of the inverter function and other system uses such as having the inverter operational at night providing reactive power support where needed.

The main objective now is to continue to develop smart inverters as a potential tool through improving standards like IEEE 1547 and their successful implementation. Interoperability will be a significant issue given the diversity of inverter manufacturers and potential differences in the implementation of the standard given the flexibility allowed under the revised IEEE 1547.

Cybersecurity considerations are also important for any grid interconnecting DER. This is particularly true for inverters. Development of distribution level cybersecurity requirements is essential for grid systems as well as those of DER providers and device manufacturers. In an integrated grid, all interconnected resources are part of the cyber footprint. Overall system security is only as strong as the weakest link – today a weak link is the integration of DER especially those used for grid management.

From there, it will be to create clear interconnection requirements that allow these devices to support the grid securely. Smart inverters are not yet ready for grid support, as they are still undergoing demonstrations and the grid controls systems, like DERMS, are still at an early stage of development. The results of these demonstrations should inform the next steps in the use of smart inverters. Smart inverters are not the only power electronics devices that can address the voltage issues, power flow controllers connected to the grid (typically on the secondary side of a transformer) are also proving effective. The use of these devices should also be considered where inverters won't be upgraded and where smart inverter functionality is insufficient to address the voltage quality issue.

4.5 DER AGGREGATION & OPERATIONAL COORDINATION

4.5.1 Description

Aggregation of DERs enables their use as resources in bulk power markets and to provide distribution grid services as load modifying resources. Also, market animation policies may spur merchant development of DERs to participate directly as supply resources. In general, aggregation involves coordinated operation of several to many DERs to create a single dispatchable resource portfolio under a single ESO's control interfaced with markets/grid operators. An aggregation of DERs may provide services to both the distribution operator and the wholesale market. These services could involve managing reliability through an aggregated set of diverse resources and microgrids combined with advanced information and control technologies. There will be more than one DER aggregator in a liquid market. As such, this requires operational coordination among the distribution operator and transmission/bulk power system operators and the several aggregators. This is the essential issue regarding the functions and structure of a Distribution System Operator (DSO). The following focuses on the starting point for these discussions based on the Minimal DSO concept from the comprehensive 2015 LBNL paper on DSO models and considerations.[115]

There will be more than one DER aggregator in a liquid market. This requires operational coordination among the distribution operator and transmission/bulk power system operators and the several aggregators.

Specifically, DER-provided services to the bulk power system must be properly coordinated with the aggregator and distribution operator through scheduling and real-time management. Bulk power system operators typically only "see" DERs as if they were located at the transmission and distribution (T-D) interface, usually at a substation. It is essential that these operators have predictability and assurance that DERs committed to provide wholesale services can actually deliver them across the distribution system to the T-D interface, as noted recently by the ISO/RTO Council.[116]

Additionally, the distribution grid operator must be able to manage situations where DER aggregators have potentially conflicting service commitments, such as offering the same capacity to serve the needs of the transmission and distribution network operators during the same operating interval. This physical coordination also involves ensuring that DER dispatch (via direct control or economic signal) does not create detrimental effects on the local distribution system. Both require schedule and dispatch coordination with aggregators at the T-D interface between the transmission and distribution network operators.

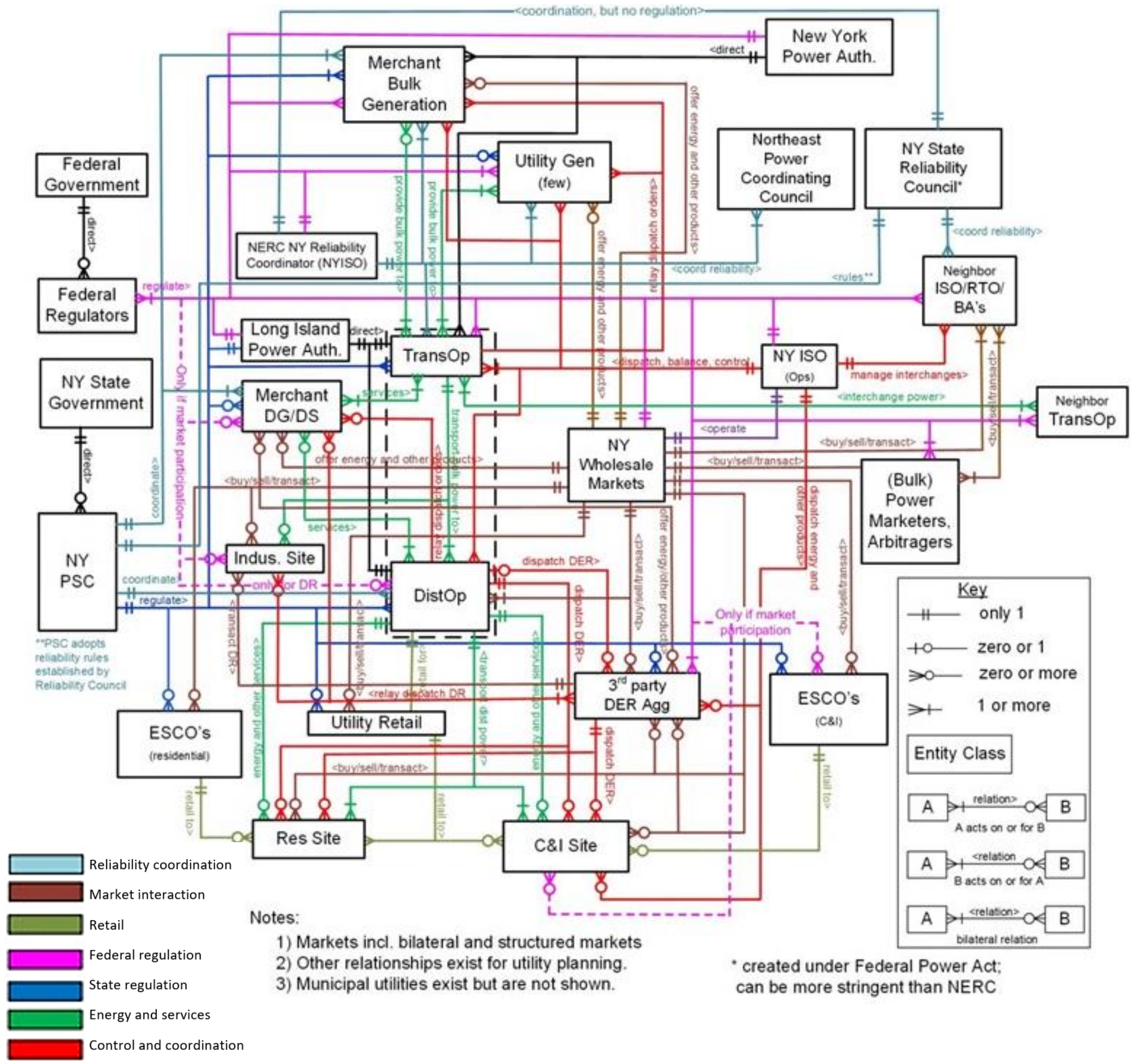
4.5.2 Decision Considerations

4.5.2.1 Architectural & Design Considerations

One of the first issues to consider is the coordination framework and related control structure. While it may seem simple to interface DERs through an aggregator as already done for years with demand response aggregators and utility programs, this is not the case with larger scale DERs and their participation in both wholesale and distribution operational services. Discussions in California[117] and New York[118] over the past two years have highlighted the challenges in evolving the demand response model for larger scale, greater DER diversity, and the variety of services that may be provided by energy storage or combinations of various DERs, for example. Central to these discussions is the 3-way operational coordination model between the aggregator, bulk power system and distribution operator. This includes the consideration of a distributed, layered control structure that enables this coordination model.

An industry structure map can help identify the challenges with changing the interrelationships and/or adding new entities and relationships into the existing structure. An example structure developed by PNNL for New York is below in Figure 24.

Figure 24: PNNL Industry Structure Model of New York



The complexity of the New York system is similar to other restructured states with an ISO/RTO and provides context for the issues to address. The main point of such a diagram is that changes to one role or relationship can have multiple unintended consequences if not understood.

Another aspect of the coordination framework is the control structure. There are a couple of approaches discussed regarding "who" controls the DER resource. One approach is that a system operator (either the bulk system or distribution) directly dispatches the DERs through their control system and secure communications links. The other model is that the system operator sends a dispatch instruction (e.g., price or control signal) and the aggregator in turn dispatches the DERs under their control illustrated in Figure 13 earlier.

This approach creates a layered control structure, as recommended earlier in Section 2.3.3 Grid Architecture and illustrated in Figure 6. This layered approach and coordination framework is also proposed by FERC's recent proposal on energy storage aggregation calling for ISO/RTO market rules that include "coordination between the regional transmission organization or independent system operator, the distributed energy resource aggregator, and the distribution utility."[119]

4.5.2.2 Enabling Technology

Technologies needed for aggregation, coordination and utilization of DERs to provide distribution grid services fall into the grid operation and market operations groups. The physical coordination and control technologies involve situational awareness and distributed resource management technologies. Situational awareness includes sensing and measurement, network model and state estimation. The discussion in Section 4.2 provides context for these enabling technologies. Distributed resource management is in the midst of a technology shift from single purpose demand response management systems (DRMS) used to manage utility DR programs to more sophisticated DER management systems (DERMS). The shift in technology is occurring due to the increasing use of other types of DERs for grid operations. This is creating demand for a single software system to optimize the use of all DERs and third-party aggregations of DERs (which currently installed DRMS' are not able to do).

However, as described in Volume II, DERMS technology is in an early stage of operational demonstration with market and operational factors driving the various levels of maturity of products. The power industry grapples with a single unified definition of DERMS. This is due to the varying opinions of the envisioned operational and technical capabilities. DERMS that have been deployed to date are also highly dependent on protocols and custom interfaces specific to each project, as the uniform application and availability of certain interoperability standards is a significant gap. [120, 121, 122 123]

Currently, a DRMS and DERMS may coexist in transition, but the industry is moving toward a single unified system to manage all DERs providing grid services, including those in DR programs, individual assets and third-party aggregated resources. Irrespective of this evolution, both alternatives drive similar needs in grid modernization as described in Volume I.

DER optimization tools are also required as described below in the implementation considerations. These are generally in R&D stage of adoption maturity. Today, assessment of DER non-wires alternatives portfolios at the distribution level is often performed through spreadsheet-type analysis. Some DER portfolio optimization capability is included in a DERMS, but these are typically designed for managing the dispatch function, not for constructing portfolios resulting from sourcing evaluations and distribution planning. It may be possible to extend the DERMS functionality for this purpose in planning, as well as to integrate with market operations and grid operations.

The other group of technologies involve market operations as described in Volume II. This includes market enabling portals, settlement systems and market oversight technologies. Market portals related to customer information access and system data exchange are in early commercial deployment. A few Green Button Connect implementations have been established, or are under development. Portals sharing hosting capacity information through maps and data have begun initial deployments and are in early commercial development. Other information portals such as Orange Button are under development, along with the data exchange standards.

It is anticipated that as locational market opportunities become available, online portals would facilitate the information exchange. This may develop initially as a bulletin board, or as additional information provided on the emerging hosting capacity maps. Such a portal could be further extended in functionality to support various sourcing mechanisms such as a DER procurement. This sourcing function would require secure, confidential access for market participants. It is not expected in the 5-year time horizon that a multi-sided transactional market platform will be needed or implemented as the operational market functions described in Volume I don't require it.

Settlement systems for distribution operational markets are in operational demonstrations, primarily beginning with settlement of complex tariffs and DR programs. Market compliance and surveillance tools are widely used in wholesale markets and are regarded as mature for the wholesale electricity grid, but have not yet been implemented for the distribution grid. Many of these technologies can be adapted for distribution operational market oversight. For distribution operational markets, the oversight scope will include data and information regarding assumptions and methodologies for determining locational and system value, as well as sourcing results and market bid information.

4.5.2.3 Implementation Considerations

<u>Coordination Framework</u>

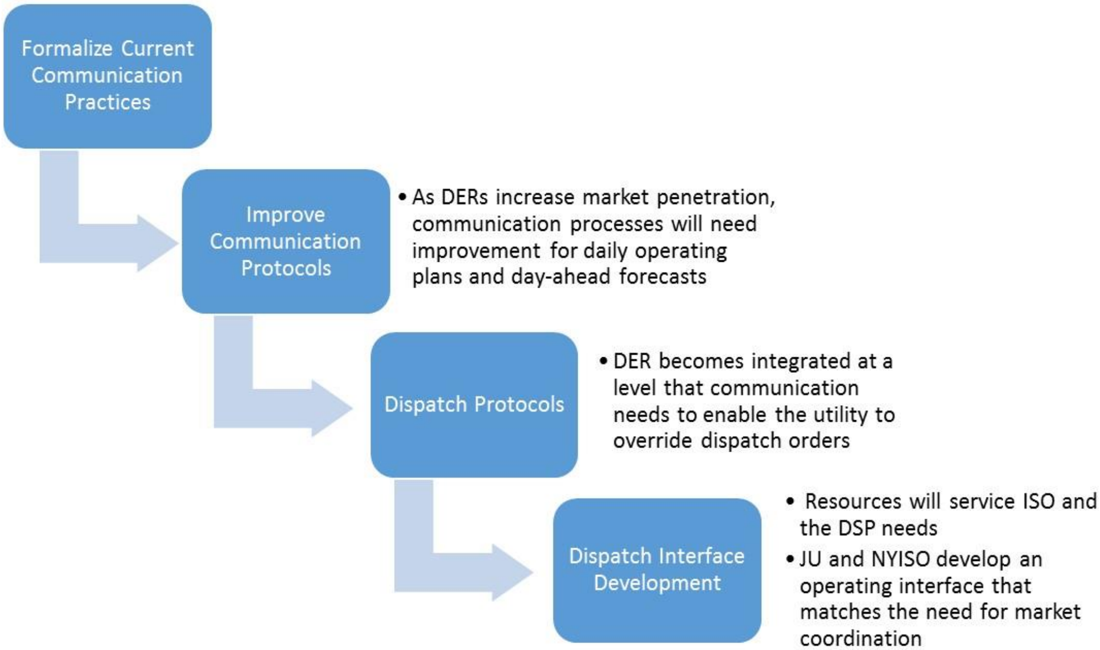
A starting point for discussions is understanding the current operational coordination of any existing utility and aggregator demand response programs. From this understanding, stakeholders can effectively discuss what needs to be done in a stepwise manner to develop a broader coordination framework that encompasses all participating DERs in both bulk power system markets and emerging distribution operational opportunities as non-wires alternatives. As an example of the types of issues being discussed in several states today, a summary from the Joint Utilities of New York (JUNY) presentation in 2016 is below.[124]

Table 3: Joint Utilities of New York Operational Coordination Summary

Currently, DERs can participate in utility and NYISO administered programs. The primary area of overlap is demand response. Demand response dispatch by the NYISO is coordinated with the JU and vice-versa. Various communication channels are used depending on the program. Near-term goals include: • Establish a formal process of cross-pollination with NYISO and the JU • Identify a process to formalize coordination standards between the parties going forward • Rules on sharing customer or resource level information may evolve over time • Establish a feedback process for DERs to communicate with the JU and NYISO In the long-term: • Utilities need to monitor penetration levels and gauge how coordination can be improved. • Using the amount of DER in queue as a trigger, steps towards a more coordinated Day Ahead forecast can be initiated • As solar PV in the queue is deployed, it will influence wholesale market mechanisms, causing further coordination issues • Reciprocity of information sharing between NYISO and DSPs will need to be established

The JUNY also proposed a multi-step approach to develop the initial coordination framework, illustrated below in Figure 25. This is offered only as an example of how to consider deconstructing the functionality and corresponding technology investments into a manageable sequence that also incorporates the interdependencies of prerequisite functions, technology and experience before taking a following step.

Figure 25: JUNY Proposed Multi-Step Operational Coordination Development



Distribution Operational Market Design

Distribution operational market design is out of scope for the DSPx effort; however, understanding the functionality and technology to support such markets is a consideration. The following is based on the current direction evolving in several states and doesn't presuppose how distribution markets may ultimately develop over a longer period than the 5-year horizon for this effort. Today, distribution operational markets are sourcing DER services through a combination of the following 3 mechanisms:[125]

- **Prices** – Time-varying rates, tariffs, marginal pricing, market-based prices
- **Programs** – DER programs operated by the utility or third parties with funding by utility customers through retail rates or by the state
- **Procurements** – DER services sourced through competitive procurements

Determining an optimal mix from these three categories, plus any grid infrastructure investments, requires both a portfolio development approach and a means to establish a comparative basis for these alternatives in terms such as firmness, response time and duration, load profile impacts and value (net of the costs to integrate DERs into grid operations).

4.6 CYBERSECURITY FOR DISTRIBUTED SYSTEMS

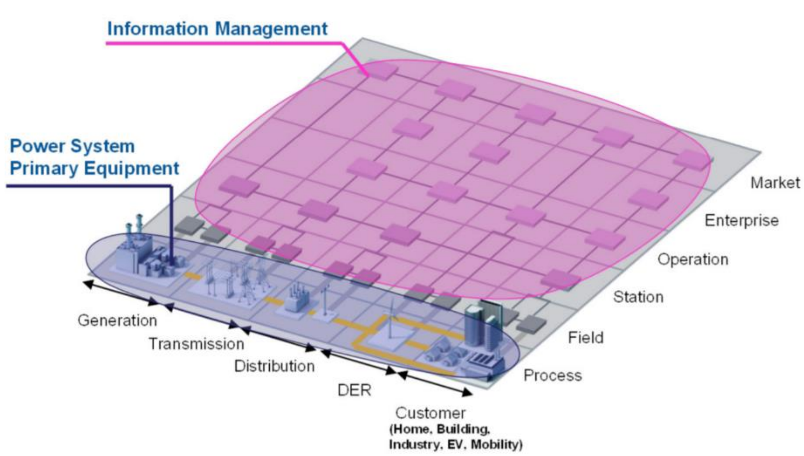
Grid modernization can add significant value to customers and society through advanced communications, sensing and computing along with the integration of thousands of distributed resources. However, a more distributed system also brings increased risks to the previously isolated and analog environment of the legacy distribution system. Cybersecurity considerations in the architecture, design and development of modern distribution systems is critical as distributed resources increasingly comprise a larger role in power systems. As noted in the NARUC Cybersecurity Primer[126];

> "***Cybersecurity must encompass not only utility-owned systems, but some aspects of customer and third-party components that interact with the grid, such as advanced meters and devices behind the meter. …With such a dynamic and broad landscape to consider, cybersecurity cannot be a stagnant prescription handled solely by experts. It should evolve along with the rapid evolution of technology, threats, and vulnerabilities, introducing the building blocks that stand the test of time while still being flexible enough to meet changing cybersecurity requirements***."

4.6.1 Distribution Grid Cybersecurity

The transformation of traditional energy networks to smart grids requires an intrinsic security strategy to safeguard this critical infrastructure. As discussed in the EEI "State of Distribution"[127] paper, the few distribution automation systems were largely closed, proprietary point-to-point systems that had very few interfaces to other systems. This is changing as more systems are being introduced with a myriad of interfaces and three orders of magnitude expansion of connectivity to millions of devices in the field. The increased coupling of transmission and distribution systems also increases both the system complexity and cyber security scope due to the increase in potential attack surface. Figure 26 below from the National Institute of Standards and Technology's (NIST) cyber security guidelines[128] and Department of Energy's (DoE) cyber security maturity model[129] illustrates these points for utility systems and interfaces to external parties.

Figure 26: Electric Grid Energy Delivery System Abstract Topology



Fortunately, a substantial body of knowledge and best practice is documented in NARUC's primers, NIST's standards, DoE's guides[130] and the work products of the SGIP Cyber Security Working Group[131], EPRI[132] and other industry groups. The distribution system is starting at a low level of sophistication and application of secure technology. While much attention and investment in security requirements and measures have been directed at the bulk power system over the past decade, comparatively little has been done at distribution. However, this also means that there is an opportunity to build the security in from the beginning as new systems are deployed and older systems are replaced. This has begun with smart meter systems, customer interfaces and now with distribution automation.

4.6.2 Interconnection Cybersecurity

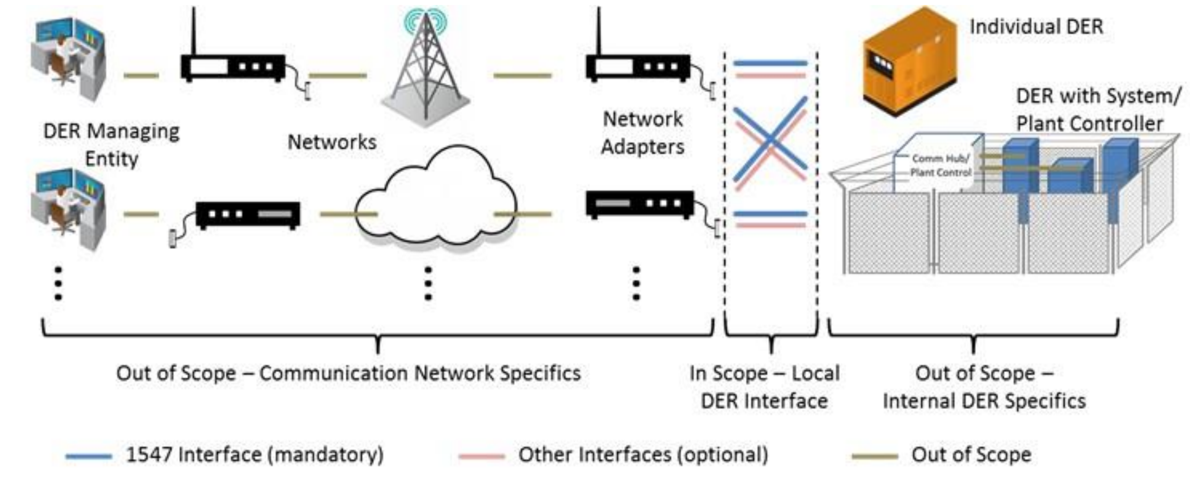
Cybersecurity considerations are also important for any grid interconnecting DER. This is particularly true for inverters. Development of distribution level cybersecurity requirements is essential for grid systems as well as those of DER providers and device manufacturers. In an integrated grid, all interconnected resources are part of the cyber footprint. Overall system security is only as strong as the weakest link – today a weak link is the integration of DER, especially those used for grid management.

In a new paper, EPRI summarizes the treatment of cybersecurity in the proposed revision to IEEE 1547.[133] In simple terms, IEEE 1547 enables, but does not directly specify, cyber security. Cyber security is expected to be addressed in the communication networks linked to DER and inverters. Communications networks are out of scope in IEEE 1547. Cybersecurity, under IEEE 1547, is not mandated at the local DER interface.

IEEE 1547 enables, but does not directly specify, cyber security – responsibility falls on inverter manufacturers and ESO's to establish security for aggregated devices.

The IEEE working group believed the risk associated with onsite manipulation of an individual DER through its communication interface is only equivalent to the existing risk from physical tamper to the disconnect switch, for example. This is because only one DER is involved in such cases. However, this is a very narrow perspective, as most smart inverters are expected in practice to have one or more points of aggregation. One point of aggregation is the interface that the inverter manufacturers are expected to maintain to monitor performance and provide software updates to each inverter. A second interface is with DER aggregators that control the inverter/DER for critical grid services. A breach at a single device could be exploited to compromise an entire manufacturer's and/or aggregator's inverters/DER. As identified in Figure 27 below from the standard, the ESO's (or manufacturers) systems and communications are out of scope for IEEE 1547.

Figure 27: IEEE 1547™ Scope of Communication Applicability



4.6.3 DER Aggregator Cybersecurity

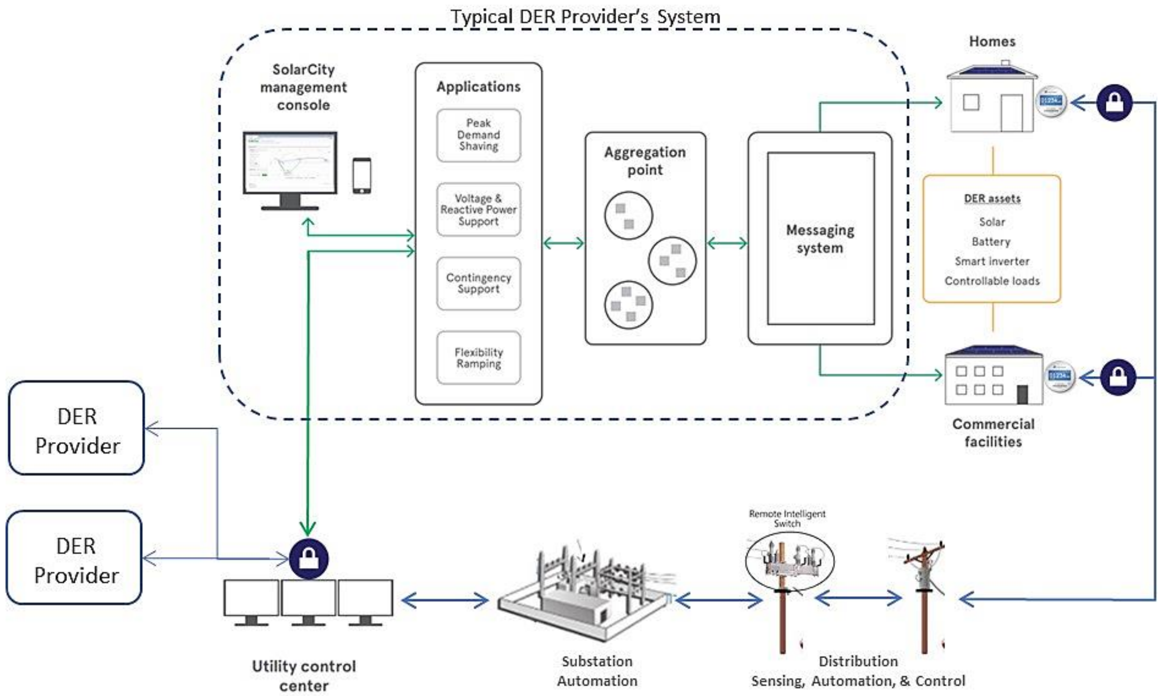
An attack on multiple inverters or DERs through a compromised network could occur either top down from the controlling system or bottom-up through a compromised device working back up into an aggregated system. Such an attack on the aggregated devices could have very large consequences for the power system and customers. As highlighted by Sandia National Laboratory their recent report:[134]

> ***"When integrated with energy demand management programs and technologies, these combined technologies significantly increase the attack surface of the national power grid and opportunity for risk to system operation from malicious actors."***

This issue already exists since some DER manufacturers and ESOs have connectivity to large numbers of devices. A DER manufacturer and ESOs investment in sensing, controls and communications should be viewed as complementary to the utilities investment in core cyber-physical grid platform technology. It is also important to note that many ESOs' and manufacturers' communications are typically provided over the public internet and through a customer's Wi-Fi or wired communications. This approach to communication is wholly independent of the grid and grid devices and does not have the reliability, service quality and cybersecurity required for critical infrastructure.

As illustrated in Figure 28 below, utility systems and interfaces with edge devices and ESOs are secured according to the best practices described in the NARUC Primer.[135] The same expectation is required for aggregated DER/inverters, whether by manufacturers or ESOs. Today, there is no cybersecurity requirement or oversight on the aggregated DER/inverters. This is a significant gap and has very material consequences on overall electric system security as DER adoption becomes a large portion of system resources. An attack on a single manufacturer's system linked to all their installed inverters, for example, could disconnect all inverters and create major system instability – possible transmission level outage. Cybersecurity codes should be established for DER/inverter managing systems and networks.

Figure 28: DER Aggregator & Utility Communication/Security Interfaces



Adapted from SolarCity & Joint CA Utility Presentations at CPUC Workshop on Jan 24, 2017

4.6.4 Approaches to Cybersecurity

There are two philosophical approaches that are complementary to develop and implement a cybersecurity strategy for a networked grid: compliance standards and processes, and risk-based management. Once a strategy is developed from compliance and risk based approaches, a range of technical solutions can be used to address identified cybersecurity needs in modern grids.

4.6.4.1 Using Compliance as a Basis for Cybersecurity

The owners and operators of grid infrastructure have been addressing cybersecurity over the past 20 years. NERC has developed the Critical Infrastructure Protection (CIP)[136] standards and processes that require the operators of the bulk power system to take steps to conform to specific cybersecurity practices. These standards include assessing the systems, determining any specific vulnerabilities, and mitigations as part of a compliance regime. Regulators interested in cybersecurity for an integrated grid should consider what NERC require for the bulk power system.

4.6.4.2 Using Risk as a Basis for Cybersecurity

A risk-based approach involves understanding the relationship between vulnerability threat, and consequence.[137] A risk-based approach starts with the assumption that an unauthorized user can and will gain access to a system. The level of security employed is based on the value of system that could be compromised. Employing this method, an entity needs to prioritize systems based on their reliability impact, privacy considerations and business value. A risk assessment that identifies and addresses the most significant cybersecurity issues across and within the system will always yield better security results than ineffective “outer wall” approaches to cybersecurity that only focus on denying access to the system.[138]

4.6.4.3 Cybersecurity Techniques

A great deal of knowledge exists on how to secure software, devices, and importantly communication networks that can be applied in an architectural approach that supports either compliance based or risk assessment based approaches. For example, in communications security there are 30 measures that may be employed as listed in Table 4 below. This is provided only to illustrate the breadth and depth of techniques available and why a compliance and risk-based strategy is a prerequisite, as all of these techniques are not required for every situation. Deciding which to use requires an organized and prioritized approach to implementation.

Table 4: Communications Network Security Measures

30 Network Security Measures

- Crypto: link layer, group, and application layer; GDOI, as it has been incorporated into IEC 61850-90-5 specifically for PMU network encryption
- RBAC (RADIUS and TACACS; AAA; NAC)
- Mutual authentication; EAP and media independent identity protocols
- Posture assessment
- X.509, secure key generation and management, scalable key management (DMVPN, GETVPN for example)
- SIEM, firewalls
- IPS, including SCADA IPS signatures
- Containment: Virtualization and segmentation (VRF – virtual routing and forwarding, MPLS VPN and VLAN); data separation
- Tamper resistant device design, digitally signed firmware images
- Digitally signed commands
- Rate limiting for DOS attacks
- Wire speed behavioral security enforcement
- Packet tamper detection, replay resistance
- Air gapping (physical network isolation, data diodes)
- SUDI 802.1AR (secure device identity)
- Access control: VLANs, ports
- Storm detection and traffic flow control: traffic policing and port blocking
- ARP inspection; DHCP snooping
- Honey pots/honey nets/sinkholes
- Unicast reverse path forwarding (IP address spoofing prevention)
- Hierarchical QoS
- Security policy managers
- MAC layer monitoring
- Control plane protection (coarse packet classification, VRF-aware control plane policing)
- Secure code development and code hardening (against buffer overflow, self-modification; remove unnecessary protocols)
- Structural/topological security
- Six wall physical security for devices and systems; access detection and mitigation (i.e. port shutdown)
- Manufacturing supply chain security management
- Data quality as tamper detection
- Anti-counterfeit measures

5 CONCLUSION

The three volume Modern Distribution Grid Report provides state commissions with a blueprint for grid modernization using a modular structure, from which states can choose depending on their specific state goals, and that can be built out at varying paces, as customer needs dictate and cost-effectiveness is demonstrated. Three strategic concepts are considered by policy makers and others:

- Adopt technology innovations to increase customer value, system reliability and resilience
- Enable customer choice at the pace of customer DER adoption; and
- Create markets for DERs which in turn will create customer value through system efficiencies

This Decision Guide specifically provides guidance to facilitate conversations around two important questions: 1) what considerations are of particular importance within a grid modernization decision process? and 2) what considerations should be given to timing and pace for states beginning to consider grid modernization?

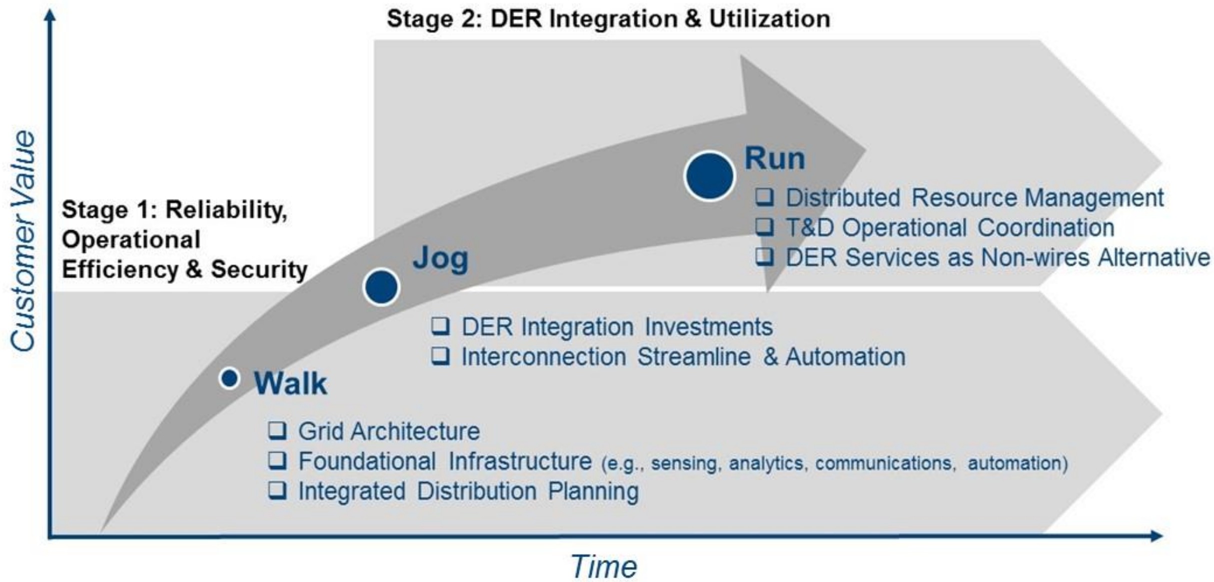
5.1 SUMMARY OF DECISION PROCESS

The decision process described in this volume is based on a classic stage-gate methodology that is rooted in a focus on satisfying customer needs and societal objectives. It is this customer-centric approach that is intended to align grid modernization efforts to realizing value for all customers. It is also important to start by defining the end goal – identify the objectives and attributes. The Ohio PUC's PowerForward initiative, for example, is taking a similar approach.[139] This clarity provides the necessary input to develop a grid architecture and subsequent designs and technology selections. Establishing the relationships to customer value also inform the deployment of an implementation roadmap aligned to pace and scope of customer value.

5.2 TIMING AND PACE CONSIDERATIONS

A question often asked is, "Where do you start?" The U.S. distribution system is currently designed for traditional one-way flow and not thousands of DER contributing as resources to the system. This is Stage 1 in the distribution grid evolution. The issues are whether and how fast to transition into Stage 2. As mentioned above the pace and scope of investments driven by customer needs and policy objectives. The specific engineering need for changes to the grid will be derived from forecasting customer needs and the effects of policy in a holistic integrated system planning process. Such a planning process will integrate resource, transmission and distribution planning leveraging stakeholder engagement to improve input assumptions and buy-in on results of the analysis.

Figure 30: Stage 1 to 2 Evolution via Walk-Jog-Run Approach



In the initial Walk step, there are three key aspects to consider: 1) Develop and implement a transparent distribution planning process that is integrated with resource and transmission planning; 2) In conjunction with the planning, develop a grid architecture with an emphasis on a layered, distributed approach and interoperability based on open standard; and 3) Leverage this architecture to identify the necessary foundational cyber-physical Infrastructure and other core platform components. Cybersecurity must be addressed in the architecture and grid as a platform designs and related technology.

The next Jog step focuses on integrating DER at larger scale and the related enabling distribution investments. This also involves DER interconnection process re-engineering to streamline and automate to improve transparency and customer experience.

The final step (Run) to reach full Stage 2 functionality involves utilizing aggregated DER services for grid operations. The integrated planning process will identify opportunities for DER services as non-wires alternatives. Advanced technologies to manage aggregations of DER are implemented and processes are needed to coordinate transmission and distribution operations.

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