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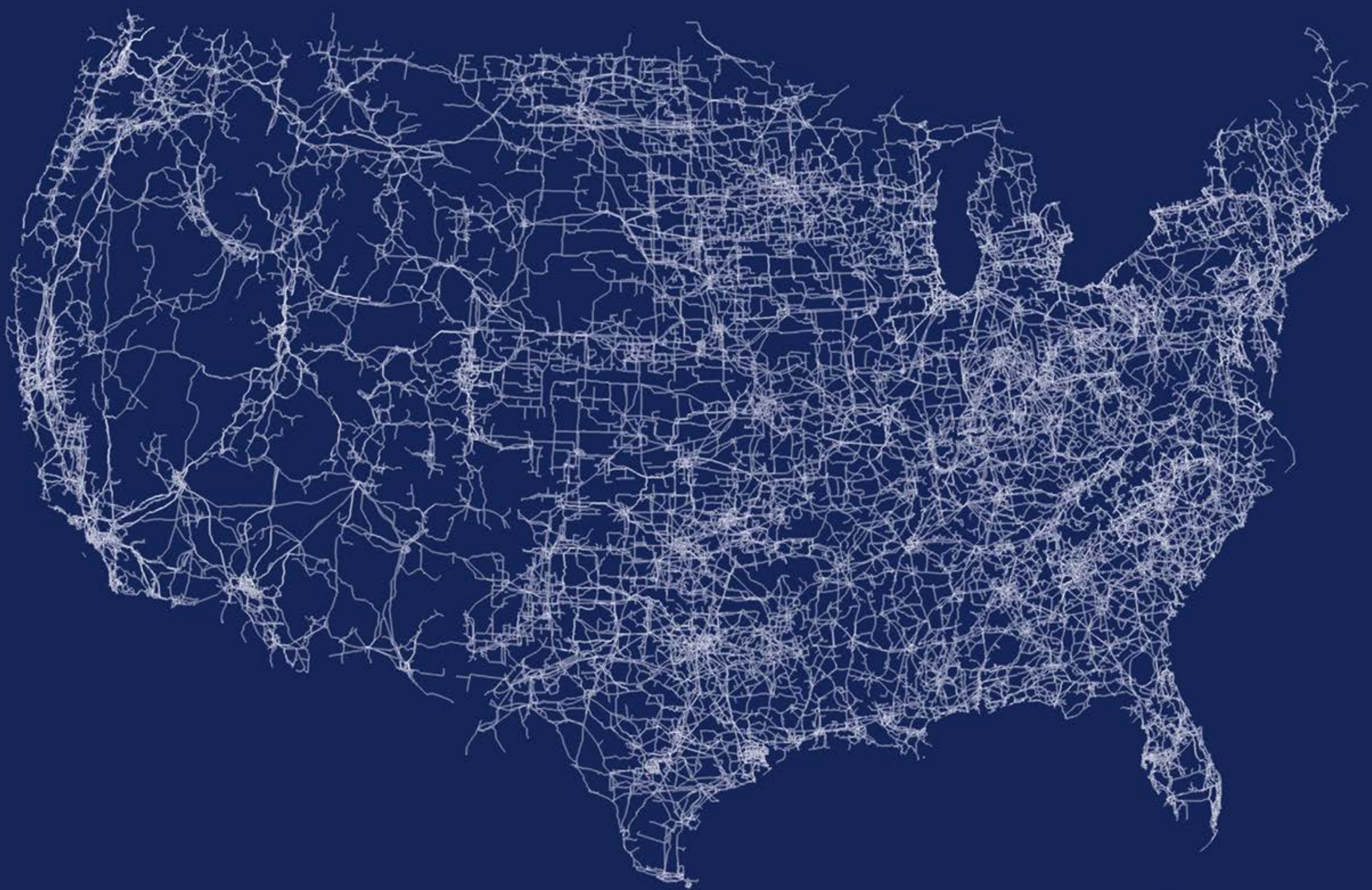

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Electricity Transmission System Research and Development: Distribution Integrated with Transmission Operations

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Electricity Transmission System Research and Development:

Distribution Integrated with Transmission Operations

Transmission Innovation Symposium:
Modernizing the U.S. Electric Grid

2021 White Papers

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Foreword

The foundation of the U.S. Department of Energy (DOE) Transmission Reliability research program was established 20 years ago through a series of commissioned white papers. The white papers reviewed the dramatic institutional and regulatory changes that the transmission grid was undergoing and articulated the technical challenges that those changes created. The challenges outlined in those white papers were used to formulate the initial research goals of the Transmission Reliability program. Today, 20 years later, many of the targets set out for the program have been accomplished. At the same time, the electricity grid is undergoing a dramatic shift with the addition of substantial renewable and distributed energy resources and heightened risks from phenomena such as severe weather. These shifts pose new challenges for the transmission grid, today and into the future. As a result, now is an appropriate time to step back and review the current technical challenges facing the industry and to identify the next set of targets for DOE's transmission-related research and development (R&D) programs within the Office of Electricity's Advanced Grid Research and Development Division.

To support this process, DOE, supported by Lawrence Berkeley National Laboratory (LBNL) and Pacific Northwest National Laboratory (PNNL), has commissioned small teams of experts drawn from the national laboratories and academia to prepare a new set of foundational white papers. Each white paper reviews and assesses the challenges now facing the U.S. transmission system from the perspective of the technologies that will be required to address these challenges. The focus of the white papers is on technical issues that must be addressed now to prepare the industry for the transmission system that will be required 10-20 years in the future. A key purpose of these papers is to identify technical areas in which DOE can take a leadership role to catalyze the transition to the future grid.

The five white papers are:

1. **U.S. Electricity Transmission System Research & Development: Grid Operations**
   Lead Authors: Anjan Bose, Washington State University, and Tom Overbye, Texas A&M University

2. **U.S. Electricity Transmission System Research & Development: Distribution Integrated with Transmission Operations**
   Lead Authors: Chen-Ching Liu, Virginia Polytechnic Institute and State University, and Emma Stewart, Lawrence Livermore National Laboratory

3. **U.S. Electricity Transmission System Research & Development: Automatic Control Systems**
   Lead Authors: Jeff Dagle, Pacific Northwest National Laboratory, and Dave Schoenwald, Sandia National Laboratories

4. **U.S. Electricity Transmission System Research & Development: Hardware and Components**
   Lead Authors: Christopher O'Reilley, Tom King, et al., Oak Ridge National Laboratory

5. **U.S. Electricity Transmission System Research & Development: Economic Analysis and Planning Tools**
   Lead Authors: Jessica Lau, National Renewable Energy Laboratory, and Ben Hobbs, Johns Hopkins University

The white papers will be vetted publicly at a DOE symposium in spring 2021. The *Transmission Innovations Symposium: Modernizing the U.S. Power Grid* will feature expert panels discussing each white paper. The symposium will also invite participation and comment from a broad spectrum of stakeholders to ensure that diverse perspectives on the white papers can be heard and discussed. Proceedings will be published as a record of the discussions at the symposium.

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Table of Contents

List of Figures

List of Tables

Acronyms and Abbreviations

ADMS	advanced distribution management system
AI	artificial intelligence
AMI	advanced metering infrastructure
DER	distributed energy resources
DERMS	distributed energy resource management system
DIS	distributed information system
DOE	U.S. Department of Energy
DSO	distribution system operator
EMS	energy management system
EV	electric vehicle
FERC	Federal Energy Regulatory Commission
FRTU	Feeder remote terminal unit
IID	integrated information device
ISO	independent system operator
ML	machine learning
NERC	North American Electric Reliability Corporation
PMU	phasor measurement unit
R&D	research and development
RTU	remote terminal unit
SCADA	supervisory control and data acquisition
T&D	transmission and distribution
VPP	virtual power plant

Executive Summary

The anticipated future high penetration of distributed energy resources (DER) and increase in smart grid capabilities in distribution systems will significantly enlarge the role that distribution systems can play in the bulk transmission system beyond their traditional status as load. The transformation of distribution systems from load to subsystems of the transmission grid that incorporate generation, energy storage, electric vehicles (EVs), control, and trading activities will strengthen the interdependency between transmission and distribution (T&D) in the areas of operations, controls, and markets. This white paper presents a vision of a future grid in which distribution systems are integrated with and play a supporting role in transmission grid operation. We describe the pathways toward, and make recommendations for, realizing this vision through both U.S. Department of Energy (DOE) activities and integration of industry activities.

In our vision of a future integrated T&D system, DER provide collaborative, coordinated operational support for both transmission and distribution operations. An increase in renewable electricity and energy storage will facilitate reduction in climate impacts through retirement of major greenhouse-gas-producing assets. In the grid of the future, non-wire alternatives will be commonplace. Large-scale trading in electric energy and ancillary services will be carried out in an integrated T&D environment where distribution system operators will also serve as distribution system reliability coordinators. Data on demand and DER will be widely available through a networked information environment that will enable operation, control, and trading. Computational tools, including optimization and artificial intelligence/machine learning (AI-ML), will be available to support this integration. A hybrid, intelligent decision-support environment will combine human operators and AI tools. Cyber and physical system security and privacy will be ensured by comprehensive procedures and advanced monitoring, detection, and mitigation technology. The integrated T&D system will have the capability to recognize and mitigate threats from extreme events such as major hurricanes, earthquakes, wildfires, and cyber intrusions. Training and development will be in place to prepare a workforce well versed in advanced optimization and AI/ML tools and able to function effectively in the future integrated T&D environment.

To achieve this vision of an integrated T&D operational environment, we offer recommendations for DOE research and development, organized into five categories that reflect the five architectural layers we define for the future grid environment. Those layers are:

1. Enhanced Data/Information, supporting information availability and communications
2. Data Analytics and Protection/Control Technologies, supporting high penetration of DER and non-wire alternatives
3. Grid Decision-Support Environment, Tools, and Communications supporting hybrid human-AI decision making
4. Operators and Control Centers, which reflect a changing workforce
5. Cyber Security and Privacy, supporting a secure integrated environment

For Layer 1, Enhanced Data/Information, we recommend development of a cohesive plan for sensors, measurement, communications, and advanced analytics for an integrated T&D environment. A critical enabling infrastructure, which we refer to as a distributed information system (DIS), would be developed by design and testing of information and communications technology for widespread deployment in a network of integrated information devices (IIDs). Test systems, models, and tools need to be developed to validate analytics for the integrated T&D system.

Recommendations for Layer 2, Data Analytics and Protection/Control Technologies, include development, testing, and deployment of data analytics and tools for situational awareness of distribution systems, including developing communication tools and use cases to support decision making in the future integrated T&D grid.

Layer 3, Grid Decision-Support Environment, Tools, and Communications, recommendations include development of tools to support hybrid human-AI decision making for the integrated T&D system, including visualization of data from remote sensing devices and multi-modal sources. Staged and scaled demonstrations are recommended of AI-enabled distributed decision support.

Recommendations for Layer 4, Operators and Control Centers, focus on incorporating communications and visualization tools into the integrated T&D system and development of a diverse workforce prepared to function in the integrated T&D environment.

The recommendation for Layer 5, Cyber Security and Privacy, is to develop cyber-physical system security and privacy tools, which will be essential for the integrated T&D system.

The proposed vision for an integrated T&D system is a pro-active, forward-looking response to important drivers of the anticipated transformation of distribution systems. A major driver is the exponential increase of DER interconnected to distribution systems. DER include renewable energy sources, energy storage, electric vehicles, and flexible load, along with the monitoring and control capabilities necessary to accommodate these assets. Economic incentives, in the form of market opportunities, are needed to facilitate future growth of DER. DER will, in turn, contribute to reliability and resilience of the integrated T&D system. Another driver of the transformation to an integrated T&D system is rapid growth in information technology and network connectivity, which will facilitate deployment of widespread data acquisition and information-sharing to support decision making by both grid operators and customers. Widespread connectivity could also make the system vulnerable to major cyber security and privacy breaches, which drives the need for development of highly secure technologies for the integrated T&D system. AI and ML have demonstrated impressive capabilities in recent years as a result of an explosive growth in data/information availability and search capabilities. This technology transformation drives the need for a future workforce of operators and engineers who are trained in new information technology and analytic tools and able to function in an operational environment that incorporates AI/ML in decision making.

The remainder of this paper is organized as follows:

Section 1 describes the background and current status of distribution systems in the context of transmission operation.

Section 2 focuses on drivers of transformation in T&D system operation.

Section 3 discusses the proposed vision of integrated T&D operation.

Section 4 describes the proposed architecture of technology and non-technological solutions for realization of the integrated T&D system vision.

Section 5 summarizes our R&D recommendations.

Section 6 presents justification for DOE funding to support the transformation to the integrated T&D system.

Section 7 summarizes the key elements of the paper—the drivers for grid transformation, the components of the vision of a future integrated grid, and our recommendations.

1. Background and Introduction

Transmission operations have long viewed the distribution grid as a load embedded within the transmission system. The distribution system has been characterized by one-way loads, non-automated communications with a long time scale, decentralized operation, a diversity of topologies and configurations, and a significant difference in total length compared to that of the transmission system. All of these historical distribution-system characteristics have implications for what will be required to realize the vision of integrated transmission and distribution operations that we describe in this paper.

A vision to integrate the decentralized distribution systems into transmission grid operations is critically needed because of the rapidly increasing presence on the distribution system of smart devices and distributed energy resources (DER), including microgrids. We envision that, in the future, the distribution grid will be viewed as a subsystem within transmission planning, operations, and control. This paper introduces a vision in which significant distribution operations and architectures function safely and securely within the transmission system.

One of the characteristics of the current distribution system that must be addressed in realizing the vision described in this paper is that the distribution system relies on non-automated communication that has a long time scale (minutes, hours, even days) and depends on manual control of assets. These distribution-system characteristics are in contrast to the rapid, automated communication and resource-dispatch that are possible on the transmission system.

As mentioned above, another major difference between the transmission and distribution systems is that the nation's distribution infrastructure covers a number of miles that is more than an order of magnitude greater than the number of miles covered by the transmission infrastructure. On the positive side, this large scale of distribution infrastructure implies a large marketplace for solutions and their providers. However, this large scale also has its down side in the cost and effort that will be required to roll out new technology. Furthermore, distribution utilities currently rely on major infrastructure components that are aging and outdated.

Another feature of the distribution system is that it encompasses a diversity of topologies and configurations. For example, the distribution system employs different voltage levels, e.g., 34 and 12.5 kilovolt feeders, which have different implications for load growth and technology upgrades. An example of the varying distribution system topologies that have developed over many decades is the difference between metropolitan areas, which are characterized by high-density load served by underground secondary networks, and suburban areas that have relatively lower-density loads and tend to have more rooftop solar facilities and electric vehicles (EVs). Technology development for future transmission and distribution (T&D) integration must take into account this diversity of distribution system characteristics.

As innovation accelerates, decentralized and automated controls will operate faster and with high precision, enabling new decision-support tools for human operators and new market opportunities for asset owners. This paper focuses on the transmission side of technologies and operations; we touch on key distribution components, but we do not describe the mechanisms by which the future distribution system will be developed. Safe, secure, and equitable distribution operations must be addressed by U.S. Department of Energy (DOE) programs focused on areas such as microgrids, energy efficiency, and renewable energy.

This paper introduces a vision of future grid operations up to the year 2040, addressing the current state of the grid, key drivers for transformation of the grid, and why and how federal funding should support the research and development goals to enable this vision of the grid of the future.

1.1 Moving to a Virtual "Grid of Grids"

The vision that we present in this paper of technologies for future distribution system operations within the transmission system is a move away from the traditional view of grid operations. The future we envision for T&D operations is a single cohesive environment providing clean, resilient, reliable, secure, and affordable energy delivery to consumers. In this vision, the interaction and role of distribution operations will shift from its current state to one that enables a much larger suite of technologies to be developed and deployed. The role of distribution operations is envisioned to shift much more significantly than the functioning of the transmission system in the sense that, the anticipated high penetration of very visible, automated, distributed renewable resources will drive the distribution system to rely on data-driven, distributed computation and intelligence to ensure resilience and reliability. Although the need for movement of bulk power over long distances will remain, the penetration of large-scale renewable energy resources will continue, and, as a result, distribution will become a more active controllable resource. Controls will need to be faster than real time, i.e., predictive and preventative, and human operators will need significant data-driven, analytical decision support. The power system will become a "grid of grids," that is, a transmission system with many subsystems. Standard operations will be needed for virtual power plants (VPPs),[1] microgrids, meshed networks, and predictive reconfigurations. Although there will be human operators in both transmission and distribution systems, the decision making will be far more automated than it is today, and driven by a wealth of data and analytics.

In this future operational environment, management of day-to-day operations and control of factors such as voltage and loading will be automated. Visualization of this network at the transmission operations level will be purely data driven, and far more information will be available than is the case today. Operators will have insight and perspective on the predictive capabilities of a large-scale, dynamic system; from the transmission side, the distribution system will no longer be viewed, as it is today, as a static load. The state-estimation tools required to make this possible will be driven by data, optimization, and artificial intelligence (AI), with advanced visualization and user interface support for

[1] A VPP is a group of distributed energy resources that is under central operation and control so that it can provide reliable energy and services.

system operators. Resources will actively participate in new market structures with automated optimization to ensure the markets balance the multiple priorities that will need to be addressed. Asset owners will also have their own optimization goals.

Data, and the architecture for its incorporation in advanced automation, will drive the new operational environment. The information layer will transform data into useful insight, providing operators and intelligent operational systems with key status updates, supported by real-time computation and predictive capabilities.

The future operations environment described here takes into account that some utilities might adopt more or less advanced distribution technologies than others. The technology we propose can be employed by utilities that choose to adopt limited distribution technologies, utilities that take a middle road with a mix of advanced and less-advanced technology, and utilities that fully adopt advanced technologies and enable all automation and response features. We make a baseline assumption that the transmission system must be able to operate safely and securely in a setting with mixed levels of technology adopted by different utilities but, where certain minimum conditions are met, central command and control, along with optimization- and AI-based decision support, and operations of highly decentralized systems must be enabled. Operations technology needs to be advanced to a minimum suggested level to be applicable across a spectrum of scenarios.

As current boundaries of service are becoming blurred, coordination between transmission and distribution operation entities is often challenging and can limit growth, improvement, and adoption of new technologies. Typically, new markets (often initiated by consumers) for services, such as demand response, support the transmission system while simply doing no harm to distribution. Independent System Operators (ISOs) at the transmission level use these market resources, which often operate at the distribution level, to support reliable operations. There are regulatory and technology barriers to this evolution. Timely action is needed to ensure that the requirements for distribution and transmission operations to synchronize and operate as a single energy delivery system can be met. Each of these issues, challenges, and opportunities is discussed in the subsequent sections of this paper.

This paper focuses on the future integration of transmission and distribution operations, the drivers for this change, the data and technology needs associated with this change, and research goals to realize this future vision. We also discuss the operational requirements and view of the distribution grid on its current trajectory towards an active, self-healing, automated energy delivery system that forms an integral part of the transmission operations environment. Although it is unlikely that the distribution system will be fundamentally reconstructed during the next 20 years, the large-scale deployment of DER, including EVs, can enable the transmission and distribution grids to evolve toward a single, dynamic entity, or a grid of grids with an unprecedented new level of data and decision support. To accomplish this, the distribution grid will have to be secure and responsive, providing the right information to the right people and entities in the right way at the right time.

1.2 Drivers of Change

Current drivers of changes that would enable integrated operation of transmission and distribution include:

- The expected exponential increase in DER and renewable generators, along with retirement of traditional assets
- The need and desire for non-wire yet operational alternatives that have market-participation features
- Maturation of analytics technologies in relevant fields
- Need for advanced communications and information availability for both operators and customers
- Stakeholder engagement and a changing workforce
- Security and resilience in changing risk and threat environment

1.3 Organization of Paper

In Section 2, we discuss the transformation of the distribution system—its historical development to its current state—and some of the drivers for change. Section 3 presents a vision for a future distribution operations environment as an element of transmission operations. Section 4 discusses the architectural needs to implement integrated operating environment as well as implementation issues. Research and development (R&D) recommendations are provided in Section 5. Section 6 discusses the justification for DOE funding for this transformation of the grid, and Section 7 summarizes the key points presented in this paper.

2. Energy Delivery Operations Are Undergoing a Major Transformation

The distribution operations environment is designed to plan and operate the distribution system; manage outages within industry standards; rapidly recover from events; and maintain remote monitoring and switching capability for safety, reliability, and service restoration. To comply with the industry standard for operations, reliability metrics are used for performance monitoring and comparison. Change in the distribution operations environment is challenging because the current system effectively works to the standard required in the majority of cases. Technology change is being driven by current operational "edge cases" on the distribution grid. These edge cases have occurred in areas where there are weather-related incidents (e.g., from increasingly frequent or severe hurricanes and wildfires) and a high penetration of distributed resources.

The utility environment must be upgraded in a manner that maximizes performance, minimizes regret, and enables the system to adapt to fast-moving technology changes. Environmental drivers and changing customer perspectives serve as bellwethers that transformational and proactive change is needed in distribution and transmission operational systems, particularly in regard to information integration.

In this section, we first discuss, in Sections 2.1 and 2.2, the history of distribution operations, their integration with transmission operations, and the current status of the transmission-distribution interface. In Sections 2.3–2.9, we discuss each of the current drivers for change:

- An expected exponential increase in penetration of DER on the distribution grid along with retirement of traditional assets
- The need and desire for non-wire-yet-operational alternatives with market participation features
- Operators' and customers' need for information
- The maturity of analytics technologies in relevant fields
- The need for advanced communications
- An increase in stakeholder engagement and the need for a workforce able to interact with the evolving T&D environment
- The need for security and resilience in an evolving threat and risk environment

For each of the above drivers of change, we examine the history of their development to this point, and the current state of technology integration related to them.

2.1 Current State of Distribution Operations and Integration with Transmission Operations

During the past 10 years, distribution operations have moved rapidly from paper-based technologies to a visual network architecture linked to geographical information systems. Similarly, but at a faster pace because of economies of scale, transmission operations have moved toward a more visual, integrated system that no longer accounts for only load but also includes as validated operational models and advanced integrated forecasting for renewable, distributed, and stochastic sources. A paradigm shift to synchrophasors has enabled more predictive capabilities and achieved close to 100% observability of the transmission system through a combination of supervisory control and data acquisition (SCADA) and phasor measurement unit (PMU) data. Sensors have been added to the distribution system at a much slower pace, with current levels of observability mostly driven by smart (remote-controlled) devices and advanced metering Infrastructure (AMI). AMI offers clear benefit to the energy delivery system, but other sensing technologies have not been adopted. There are clear boundaries between transmission and distribution operations capabilities and responsibilities, which limit the transition that each system has made to using advanced technology.

The digitization of operations has been beneficial, but technology adoption in the distribution operations environment has plateaued. Depending upon a utility's size, there can be a wide gap between traditional operations and the adoption of state-of-the-art technology. There are numerous reasons for this, including cost-benefit evaluations and risk tolerance. However, the gap between technology availability and implementation must be eliminated to achieve the vision of future cohesive transmission and distribution system operations, with distribution as an active subsystem of the energy delivery system. Drivers such as very high penetration of DER [1], make change essential. Appropriate integration of advanced technology will balance long-term costs and offer solutions for operations in challenging conditions.

The scope of distribution operations differs across the nation along with the degree to which advanced technology has been integrated into distribution systems. The extent to which newer technologies and integrated approaches have been adopted depends primarily on each utility's economic model. In a ratepayer-driven environment, piloting newer technologies, such as the advanced distribution management system (ADMS) and distributed energy resource management system (DERMS), must wait until use cases are validated by utilities that have the resources to do so, or until regulations or laws force the upgrades.

Some utilities may have a highly integrated digital distribution network management environment while others in the same region that have a different economic model and customer base might rely on a less advanced infrastructure. For example, CenterPoint's resilient operations center is built to withstand large-scale events and efficiently restore power after interruptions related to frequent hurricane conditions [2] whereas other utilities within the same region and climate conditions rely on a relatively static model of the distribution system and tabular dispatch of trouble tickets.

Across the nation, transmission and distribution operations are not integrated. There was a good reason for the lack of integration in the past because, compared to transmission systems, distribution systems have a low level of automation, and the primary operations are concerned with maintenance switching as well as outage management and service restoration by the field crew. Over time, distribution automation integration has moved slowly because of cost-benefit considerations.

The most progressive current approach to distribution operations is to use an ADMS, which integrates all distribution management, outage management, and DER applications into a single environment that provides access to data streams and significant volumes of decision support. ADMS optimization to balance priorities is key to enabling effective decision support. Some ADMS features currently being piloted include: outage management, service restoration, voltage/var control, decision support tools, and advanced sensing and smart meters.

Drivers of Change

D1: The expected exponential increase in distributed energy resources & renewable generators along with retirement of traditional assets

D2: Need and desire for non-wire yet operational alternatives, with market participation features

D3: Availability of, and need for, information for both operators and customers

D4: Maturity of analytics technologies in relevant fields

D5: Availability of communications and information

D6: Engagement of stakeholders and changes in workforce

D7: Need for security and resilience in changing threat and risk environment

As the industry evolves and moves toward integrated transmission and distribution, it will be important to find ways to coordinate renewable generation and integration goals.

To offer a glimpse of a contrast to the structure of the U.S., power grid, we note that, in many areas of Europe, there are fully deregulated operators of wire-only services, and third-party energy providers are the main consumer contact point.

2.2 The Transmission-Distribution Interface

Distribution operations differ from transmission operations in that fewer components are affected in the short-term distribution operations time frame. Each single action on the transmission system affects more customers than are affected by an action on the distribution system. The distribution system is currently seen mainly as a load to be served within the transmission system while the distribution system sees transmission as its source. As we move into the future, the distribution system will evolve into a reconfigurable entity with large-scale generating resources, which will change the system's system real-time operations.

At present, a transmission operator may interact with the distribution system when demand response is used to reduce and balance load. The transmission operator can request an automated demand response action, but the operator has limited knowledge—and confidence in that knowledge—regarding the actual demand response action taken. The distribution operator does not play a significant role in the fulfillment of the request, which takes place in a manner largely invisible to distribution operations. As a result of this set of circumstances, the use of demand response as a reliability solution is limited. Similarly, aggregators can provide service to transmission in certain areas with high penetration of DER, i.e., selling power to system operators and dispatch. Similar to the demand response example above, this action is also mostly invisible to distribution operations. As the distribution system evolves to contain more generation resources and to require far more active management, a carefully crafted integration of data and analytics will be needed to optimize operations.

The transmission and distribution operations interface is currently defined mainly by jurisdiction and voltage levels. In other words, within a substation, the transmission system operator regulates activity up to the point of demarcation, typically by voltage level, and the distribution system operator is responsible for activity from the transformer on. When we add a decentralized distribution system operator, or one or more VPPs at the feeder head, the potential for generation coming from the distribution side of the interface has to be taken into account, and any change in the DER or VPP operation may have financial consequence. Considering distribution system VPP(s) as a dispatchable or controllable unit means the stakes are high for DER incentives and power system reliability, and, therefore, real-time prioritizing and understanding of value streams will be needed. That prioritization will depend largely on who owns which function (e.g., reliability, restoration, and resilience). The key pieces of DER technology that are driving the changes on the distribution side must be understood in order to propose a shift in transmission and distribution system operations to accommodate this new dynamic.

2.3 Expected Exponential Increase in Distributed Energy Resources and Renewable Generators, along with Retirement of Traditional Assets

To understand the need for distribution operations to evolve, it is important to consider how distribution planning needs evolved in response to the advent of distributed resources and in the context of transmission reliability. Interconnection studies for distributed resources initially used the traditional distribution planning process, supplemented with specific analyses when needed, to determine the impact of interconnecting DER. If the proposed interconnection was determined to have a potential negative impact, such as voltage rise or deviation, analysis would be performed to determine a required mitigation, which could be a set-point change, voltage support, or command and control at the utility level. That information, once approved, would be passed to the operations team through a geographic information system update. Ongoing management entailed the operations team having some visibility that DER were present.

This process was unsuitable for rapid integration of a high penetration of DER, or for many interconnection requests in regions where utilities and regulators incentivize the requests with rate changes or tax benefits. Some utilities, distribution planners, and interconnection teams have evolved a process to consider clusters of DER as resource and have performed analyses to determine the holistic impact of these clusters rather than looking at the individual impact of each distributed resource. This is known as integrated or holistic planning [3]. It considers mitigation cost on a system basis. Although this type of planning has not yet been adopted throughout the nation, the process has been well vetted, is becoming standardized and well understood, and could be used as a roadmap for other utilities as the expected 25% penetration of distributed resources manifests over the next 10 to 20 years [4]. Lessons learned about the speed at which standards and codes had to adapt can be applied to the evolution of distribution operations, enabling a rapid transition to an interactive and effective solution to managing a rapidly changing distribution system.

As distribution operations evolve toward the future envisioned in this paper, they will experience not only customer-driven changes in utilization of DER and need for increased resilience and restoration capabilities, but faster-than-human controls will also come into play to enable a self-healing system. A similar evolution of planning for high penetration of controllable distributed resources is needed for their future operation now and in 20 years. Integration of DER and smart devices will continue to accelerate, and new business models, such as aggregators, will continue to emerge to enable customers to benefit from this integration. In this study, rather than attempting to encompass the entire evolution of distributed resources and the smart grid, we focus on VPPs and microgrids as foundational technologies for integrated T&D operations.

2.3.1 Virtual Power Plants

VPPs are a technology that is likely to become more significant and routinely used in grid operations during the next 20 years. A significant amount of research and development (R&D) has been performed on VPPs during the past decade, particularly in Europe, e.g., [5]. From the transmission operations perspective, a VPP functions as a generator, clustering a group of generation resources at a particular node (region or transmission zone). A VPP is often a combination of private customers, such as large stores with solar rooftops. The VPP enables the clustered generators to participate in markets as a single group, which increases the revenue opportunity for smaller units within the VPP group. The units participating in the VPP retain their individual ownership. Unlike microgrids, VPPs are not hardware- and technology-driven islands or units; VPP control is largely software driven [6]. VPPs can provide reserve, frequency, and balancing services. An essential requirement of a VPP is that it combines participating units into a single entity with enough resources to move the needle in transmission operations. In some situations, VPPs, from a technical standpoint, might not be effective to provide ancillary services to meet distribution system operating constraints or to provide resilience services. However, recent Federal Energy Regulatory Commission (FERC) Order 2222 stimulated an increase in interest in VPPs because it allows small to mid-size utilities to act as sole aggregators of DER in their territories.

VPPs in many pilot cases have proven some ability to provide effective service within balancing time frames under normal and even strained transmission operating conditions. Distribution operations generally do not have visibility to VPPs, which are perceived as simply providing wired service and an interconnection point. VPPs are likely to pose significant technical challenges as a result of the disconnect with distribution operations and their lack of control capabilities to support the operation of the distribution system, which relies on various control devices working in a coordinated manner.

Within themselves, VPPs could become distribution operators, but this is unlikely for reasons of safety and cost, so the VPP concept must optimize in relation to multiple objectives and provide benefits to both distribution and transmission if VPPs are to be integrated in significant numbers during the next 20 years. Appropriate incentives will be needed to facilitate this evolution. A vision of "many generators" is likely. The vision will include technology that integrates management of distribution and transmission and includes enhanced forecasting of the impact of multiple generators operating in the distribution system.

2.3.2 Microgrids

Microgrids are a new feature of distribution and transmission system operations that need to be addressed in a vision of the future transmission grid. Microgrids are typically separate, autonomous networks connected to the distribution system but able to operate as electrical islands. Microgrids that contain DER will play an important role as resiliency sources in the grid of the future, for example when extreme weather-related events damage distribution grids, as has happened in recent years, causing large-scale, long-duration power outages. With the goal of enhancing the capability of distribution systems to maintain service to critical load when utility sources are unavailable because of catastrophic outages caused by extreme events, the DOE Office of Electricity has done extensive work on the development of microgrids, e.g., [7]. Microgrids can pick up and serve critical load in their hosting distribution system and provide black-start power to power plants on the transmission grid [8-9]. Important R&D topics related to microgrids' role in the future power grid include options for networked microgrids and for modular and standardized microgrid design and implementation to reduce the cost of microgrid development and deployment and to enhance system reliability.

Operating and controlling microgrids as electrical islands without the support of utility systems can be challenging. Under normal operating conditions, the dynamics of the distribution systems are "absorbed" by the utility grid, so these dynamics are not observable or understood. However, on its own, a microgrid system that contains distributed generation and DER can become a complex, dynamic system. Resynchronization of microgrids is also an issue; this is generally dealt with in distribution operations, or by the owner as a service for a large customer. In sum, monitoring, control, operation, and protection of microgrids, and the distribution system in relation to the microgrid, are important issues to address to ensure resilient distribution systems. The complex planning and operational tasks associated with microgrids can be handled by human operators when appropriate decision support tools are in place.

2.4 Need and Desire for Non-Wire-Yet-Operational Alternatives with Market Participation Features

We use the term "non-wire alternative" to refer to solutions to power system reliability problems that do not entail adding transmission or distribution lines. During the past 25 years, centralized wholesale electricity markets for energy and ancillary services have been developed and operated in regional transmission systems. At the distribution level, progress has been made in implementing demand-response programs and pricing incentives for peak load shaving. In addition, distribution companies have engaged in bilateral trading of electrical energy for many years. The increasing installation of DER owned by utilities or third parties opens opportunities for these new generation resources and flexible loads to participate in value-added markets. Existing mechanisms include net metering and government subsidies or tax incentives for renewable facilities. In the future, an active distribution system with DER, including renewables, microgrids, EVs, energy storage, and flexible loads, will be able to provide electrical energy, grid control ancillary services, and black-start and resiliency support. Choices made during interconnection of distributed resources have operational significance to distribution and transmission.

Building new power lines to enhance power system reliability is costly and time consuming. To avoid the need to build new lines to deliver power over long distances, microgrids and other local generation resources close to a load center can be incentivized to provide power through market mechanisms. Significant enhancement will be needed to the infrastructure that will enable distribution systems to be active in this way in the future.

A transactive energy mechanism, e.g., a blockchain-based trading platform, can be developed to enable a large number of supply and demand agents in a distribution system environment to conduct bilateral trading without a centralized market-clearing mechanism. Each individual agent can make decentralized decisions based on his/her own cost, return, and risks. A distribution system operator can serve as reliability coordinator to ensure that power system security requirements are met while market operations are ongoing. There have been recent transactive energy pilots [10], but this technology has not so far been integrated into the power system.

Operationally, a transactive energy market means greater complexity and need for increased sensing and measurement, with associated costs.

2.5 Availability of, and Need for, Information for Operators and Customers

Data, whether in the form of a network model or measured variables, form the foundation for operating the transmission and distribution networks. The need for data is driving change. The SCADA platform forms the core of electric utility operations and is the primary source of real-time telemetry for the different systems that support utility control centers. SCADA is much more prevalent in the transmission system than in the distribution system, despite the growing need for a distribution system, or a combined transmission and distribution, communications backbone to enable collection and delivery of data to operators and consumers. New line- and phasor-based measurement technologies do not rely on a standardized communication backbone but instead favor independent or built-in communications. New information streams frequently become available to operators, for example, social media streams about events, or customer outages that are described on cable networks.

To envision future change, we must understand how information streams develop and why there are gaps in distribution-system communications as well as the nature of the growing need for data as the system evolves. Traditionally, the transmission system SCADA network (covered approximately 100% of the system, but distribution SCADA was, and still is, sparse. There is also a significant gap in data consistency between the substation layer of distribution SCADA and the AMI for smart meters. As part of smart grid development during the past several years, more than 100 million smart meters have been installed at customers' locations in the United States. Although sensing and communications infrastructure for the distribution system has been progressing in terms of the technologies available, they are at a "chicken and egg" plateau in the sense that greater deployment of sensors is needed before data collection and communications applications can demonstrate significant benefits.

In the past, many utilities implemented their distribution SCADA platforms as extensions of the existing SCADA/energy management system (EMS) for generation and transmission operations. For those companies, distribution and outage management systems are separate applications, coupled, to some degree, to SCADA. This centralized SCADA architecture has several benefits but also significant drawbacks for system operations and maintenance. An integrated sensing system from a single vendor is the lowest-cost option to develop a consolidated SCADA platform for independent system operators (ISOs) and distribution system operators (DSOs), using common computation, communications protocols, and infrastructure across the T&D boundary (by contrast there is a higher cost to implement, operate, and maintain advanced applications on separate platforms, e.g., using different network models). The integrated system also has the lowest SCADA training requirements for T&D operations and support staff for using the graphical user interface that facilitates the interchange of resources between ISOs and DSOs. However, there are also pitfalls to a fully integrated system. For example, the typically much more frequent changes that are needed to distribution system data, compared to the number of changes needed on the transmission side, may cause frequent data disruptions to transmission operations. A linked system also means that there is a single point of failure for both T & D.

Utilities frequently flag data integration as one of their primary challenges, with non-interoperable data sources causing limitations. Operators in general have reported that they have too much data and no simple integration plans, which creates challenges in moving to more advanced technology.

Recently, based on understanding of the strengths and weaknesses of the current transmission SCADA and distribution SCADA implementation, the SCADA system is evolving from a centralized system to distributed platforms. Separating transmission and distribution SCADA enables the acquisition of best-of-breed solutions for each, from the same or different vendors; i.e., utilities are less locked in to using single vendors. The EMS platform is not linked to, or impacted by, data base changes in distribution SCADA; thus, there is more stability for transmission operations. This evolution will also facilitate the implementation of an integrated ADMS platform, with significant benefits for distribution operations, including the potential to utilize enhanced applications that enable cohesive participation in the transmission system.

Both transmission and distribution have made significant progress in sensing and measurement with the advent of high-fidelity, high-accuracy devices such as digital fault recorders, distribution PMUs, and arcing detection devices. Advanced sensing devices are beginning to emerge at the distribution system level, e.g., line fault sensing and digital fault recording, but most are designed to detect a specific event rather than provide ongoing operational optimization [11]. The SCADA capability of distribution systems is also increasing as more smart devices and DER are deployed. The Grid Modernization Initiative [12] and DOE's Office of Electricity have proposed a roadmap for the evolution of sensing and measurement to evolve [13-14].

2.6 Maturity of Analytics Technologies in Relevant Fields

Directly related to the increase in data availability over the past 20 years, machine learning (ML) and artificial intelligence (AI) are emerging as key technologies. ML at its most basic level entails algorithms that learn and adapt based on measured performance. Advanced AI is the ability of machines to make informed decisions.

AI-based methodologies have been applied to transmission and distribution systems since the early 1980s, for example for distribution system restoration [15-17] and load forecasting [18]. The ongoing international conference series Intelligent System Applications to Power Systems, which started in 1988, has provided a forum for power-system researchers and engineers who study the potential of AI-related technologies. As the result of a dramatic increase in search and storage capabilities in information and computing technologies, interest in AI and ML has grown tremendously among industry, government, and academic institutions. Nonetheless, although the ability to use data and learn in an automated power-system environment is rapidly progressing, deployment of ML and AI has been slow in utility settings, particularly in control rooms.

Intelligent system techniques have been developed for power-grid applications, including rule-based systems, neural networks, logic- and model-based reasoning, fuzzy logic, and biologically inspired and heuristic optimization techniques. Although most are currently used only in research environments, some have been integrated into ISOs. Deep -learning neural networks have proven to be powerful tools in large-scale search problems that require extensive human expertise. Various reinforcement learning algorithms are attractive tools for iterative search and adaptation problems that cannot be solved satisfactorily using optimization methods that depend on well-defined mathematical models. In power systems, this would include decision-support tasks related to advanced outage management and service restoration, resilient distribution systems, situational awareness, and vulnerability assessment. However, a lack of standards for implementation as well as issues related to computation, safety, sensing, and institutional acceptance have created barriers to these algorithms being used in power systems. Low-hanging-fruit use cases, generally for visualization, have been documented, some of which are being implemented and deployed in industry, particularly related to DER forecasting, the accuracy of which has improved by magnitudes as a result of ML implementation [19-20].

2.7 Need for Advanced Communications and Information Availability

Humans' lives have been significantly impacted by the technology developments that have enabled us to have vast amounts of information available on demand. A similar transformation is under way in the utility operations environment with a move toward a fully accessible information system for distribution grid technologies. However, there are big differences in implementation of information technology among utility systems. Broadband and high-speed communications technologies are common in large and investor-owned utility environments, but there has been slower uptake of these technologies by smaller municipal, public, and cooperative entities. Mesh networks, dependent on radio and cellular communications, have formed the foundation for AMI. One of the more advanced, communications-driven operational environments is the Electric Power Board, Chattanooga, which, in

2010, through the American Recovery and Reinvestment Act, shifted its business model significantly to include providing high-speed communications to all locations in its service territory. However, the Electric Power Board is an anomaly; although there is recent planning for rural utilities to provide fiber internet service to homes [https://www.usda.gov/broadband], there are few cohesive communications plans for future grid operational services, and questions remain regarding the security and resilience of grid communications.

Cellular communications are often used in power system R&D activities. Trial of new monitoring devices without full utility integration is a key piece of innovation. Current wireless communications use a combination of public and private networks that are not widely deployed so that they are not subject to the NERC Critical Infrastructure Protection (CIP) [21] standards that are commonly required for transmission infrastructure. Requirements for communication with utilities by behind-the-meter and larger distributed resources are driven mainly by size and nature of the connection point. Fiber and SCADA are now often installed as an interconnection option in larger plants to allow curtailment or active management of distributed resources, with the aim of minimizing these resources' impact on the system. At the smaller and aggregate level, communication with the utility is not feasible with current communications network and bandwidth constraints. Aggregators communicate with the resources within their control, which allows those resources to perform together in the market, and the aggregator separately communicates with the ISO through secure links. The individual participants in the aggregated resource group do not communicate directly with the ISO.

2.8 Stakeholder Engagement and a Changing Workforce

In a comprehensive discussion of the future T&D grid, the stakeholders must include consumers, DER owners, technology providers, ISOs, and DSOs. Consumers have become active participants in their energy delivery; "prosumers" participate in new markets and could participate in VPPs or aggregated groups of resources. To date, these activities have primarily taken place on the transmission system, but a new set of markets for distribution optimization is emerging [22]. A lesson learned regarding customer engagement during the past decade of smart meter rollout is that messaging about the benefits of a new technology is critical to its successful adoption. Smart meter rollouts were hampered by poor communication of the benefits [23] in some cases resulting in a permanent loss of opportunities. By contrast, despite communications issues, providing data to customers on their energy use and the potential for coordinating with the utility for transmission relief, such as through flex alert responses, has been successful. Stakeholders have observed a continuing increase in customer understanding of how their energy-use decisions and participation in the power system can help both themselves and the wider community.

The distribution operations workforce's current role is to manage and react, rather than optimize available resources (although ADMS and DERMS technologies are beginning to play decision-support roles). Data have become increasingly available, from synchrophasors, for example, but data in the distribution environment is primarily used offline when managing outages and events. A new generation of system operators who have likely had extensive exposure to information technology (in the course of their education as well as through recreational activities such as gaming) offers an opportunity for integration of AI and decision-support tools. This new generation of workers may lead a significant shift in how technologies are used, which could be a key driver of change. In the current generation of utility operators there is some distrust of AI/ML. However, in the integrated environment envisioned in this paper, data, and the information extracted from data, will be key.

The utility operations workforce is also less diverse than the United States average, with less than 24% of positions held by minorities or women. This disproportion reflects the statistics for the educational fields that prepare students for utility operations works; for example, only 10% of graduates in relevant engineering fields are female. Training a new generation of systems operators offers an opportunity to also expand the diversity of the workforce.

In recent years, consideration has been given to integrating adaptive technologies, such as smart inverters, voltage control, and self-reconfiguring capabilities, into utility decision-making frameworks. Integration has been based primarily on modeling of these technologies' performance in the operational environment. The actors in this case are the service companies, aggregators, and consumers. Model- and forecast-driven predictions have been successful with the limited penetration of resources currently on the power system; the success of these approaches when distributed and other resources are scaled up has yet to be assessed. A lack of granular load control has been implicated in a number of high-profile events, so we do not treat this type of control as a current widely available technology. Lack of granular load control may be a result of computational limitations; distribution operators do not, for the most part, have real-time access to large-scale computing, especially in situations when grid conditions are degraded. Significant increases in availability of data and computational resources are needed for a realistic integration of model-driven distribution operations into transmission operations.

2.9 Security, Restoration, and Resilience in a Changing Risk and Threat Environment

As we expand the definition of DER and distribution system operations integration within the larger ISO infrastructure, we must consider risk, threat, and the potential for a contested operational environment. Although few U.S.-based infrastructure attacks have focused on grid operations, situations such as the well-publicized attack on the Ukrainian power system's computer and SCADA systems are likely to occur [24]. Risks will be constantly changing as technologies change. Although the cyber defense of the future integrated grid that we envision here is not the focus this paper, security for the integrated grid must developed in tandem as grid operations develop and must be and agile enough to support a reliable, resilient, interoperable information system that grows with the grid.

Within utility operations, a separate division typically focuses on cyber protection, if that specific role exists. In contrast to how operations groups are defined, cyber security groups are typically not designated by voltage level but rather by the technological domains they manage, such as information technology, operations technology, or a specific element such as SCADA. A consistent message from operators and cyber teams during recent restoration drills is that they can no longer work in isolation in this way and that they must consider impacts spreading from the growing range of opportunities for cyber attacks on the distribution system and interconnected transmission system.

Cyber security in the distribution system currently relies on basic technologies such as passwords and firewalls. These technologies are well developed, and, when applied properly, defend the system from the majority of simple attacks. However, these strategies cannot detect or respond to advanced unknown threats. Encryption is being increasingly adopted, but the computational efficiency for large scale, on-line applications has not been clearly demonstrated. Within the system, subsystems such as SCADA, AMI, and smart devices are separated [25], which results in a lack of a comprehensive, system-level, forward-looking strategy to protect against cyber impacts.

Currently, utilities have separate cyber, operations, and planning divisions. In the future, utility responses to events must take account of an expanding threat landscape by enabling greater control capabilities at the T & D interface. Combined utility responses have been tested in exercises such as those overseen by the DOE Office of Cybersecurity, Energy Security, and Emergency Response and the U.S. Department of Defense Advanced Research Projects Agency's Rapid Attack Detection Isolation Characterization Systems Program [26]. The information derived from those exercises will lead to more significant machine-to-machine automated response capabilities that will ultimately benefit power system operators [27].

Regarding new environmental challenges to power system restoration, the deployment of DER on the distribution grid fundamentally changes the grid's design, operation, and protection philosophy, which has been based on a radial configuration of distribution feeders. With the addition of DER, outage management and service restoration tasks become much more complex. The current outage management system depends primarily on trouble calls from customers. The massive number of smart meters installed through DOE and industry-led smart grid programs were initially utilized primarily for billing and, to a much less extent, outage reporting [28]. This has situation has evolved so that there is a fuller suite of applications associated with smart meters, including remote disconnect features that can be used for system restoration [29] and visualization of outage locations [30]. Full utilization of smart meter "last gasp" outage reporting allows distribution utilities to quickly determine outage areas without passively waiting for customers' trouble calls.

Currently, most distribution feeders are radially configured, i.e., with one point of connection to the substation points in the feeder that are normally open for back-feed of power from other feeders in the event of an outage or planned maintenance. One of the operational challenges of the evolving distribution system is the move away from the traditional radial feeder network to a meshed network for both transmission and distribution operations. In a meshed configuration of feeders, system restoration can be enhanced by redundancy of power sources and delivery paths.

One more key issue related to power system restoration is the growing need for better "black start" technologies. Black start is the initial step in power system restoration following a major outage. Black-start generating units provide auxiliary power (e.g., pumps and lighting) for non-black-start units in large-scale fossil fuel plants. If black-start help from outside the power plant is not provided promptly, non-black-start units can become unavailable for several hours or even days. Because black-start resources, such as gas turbines and microgrid generators, are relatively small in size, and there are usually more non-black-start units that need help from outside than there are black-start resources to provide that help, it is a complex optimization problem to maximize generation capability and load served using the limited black-start resources available during power system restoration. Traditional approaches do not incorporate DER that are equipped with black-start capabilities. Additional complications arise regarding how and when renewable energy devices should participate in system restoration. As black-start capabilities are installed in distribution systems, coordination with transmission operators will become critical.

One important technique to address a situation, such as system restoration, in which automation may be undesirable in order to avoid complications of system behavior, is to shift to manual control of the system. If an operator moves to manual control, there must be a detailed understanding of how to implement a corrective course of action. This approach is challenging in a decentralized and distributed multi-factor environment.

2.10 Summary of the Current Relationship of Transmission and Distribution

Figure 1 illustrates the current status of distribution systems in the context of transmission operations. Traditionally, transmission and distribution operations are separated, each with its own group of operators and supporting facilities and technologies. Transmission operators can consider distribution utilities as individual units served by the transmission system. The objective of transmission operations is to maintain power system security for the wide-area transmission grid while distribution system operators manage routine maintenance and maintain voltage control under normal conditions. When events such as line faults or equipment failures occur, the operators determine actions for outage management and service restoration. For a future in which transmission and distribution operations are integrated, the relationship between, and responsibility for, operations on the transmission and distribution systems will need to evolve, as will the collection and use of data about system status. Smart meters collect energy consumption data but are generally not integrated into the operational environment to enable detection of outage locations or to support system restoration after an event. In recent years, the level of penetration of microgrids and renewable energy facilities has increased significantly, leading to greater complexity in system operations. As advanced data collection and visualization technologies become more prevalent, there will be new models visualizing power system state.

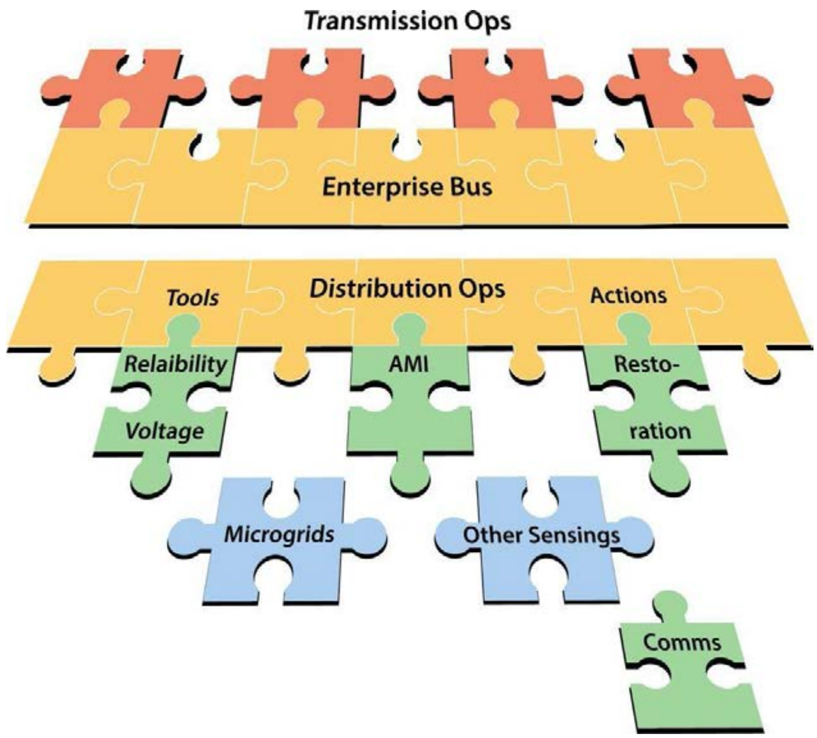

Figure 1: Current status of distribution and transmission operations

As we develop the future vision of the grid, and technologies to realize this vision, we need to recognize that T&D systems are constantly changing, from macro-level programmatic changes (such as smart grid deployment) to minute-by-minute or even second-by-second changes (e.g., intermittency of renewable energy production). For this reason, no modeling effort will, realistically, be complete or accurate.

In the future paradigm, self-sensing, self-testing, self-probing, and self-diagnostic capabilities will be desirable. These capabilities will be able to detect network configuration changes and recognize new, upgraded, or removed equipment. The new features on the grid will lead to data-driven planning, e.g., planning and modeling based on real-time topology and state estimation. This is in contrast to the current status, in which transmission planning considers distribution loads to be somewhat static except for seasonal variations, and distribution planning considers the transmission system to be an infinite bus.

3. Future Vision for Independent System Operators and Distribution System Operators

The future vision of grid operations and transmission technologies entails moving away from the traditional view of operations, particularly with regard to the interaction and role of distribution in relation to transmission. Future transmission and distribution operations are envisioned as a cohesive environment in which energy delivery to consumers is clean, resilient, reliable, and affordable. The distribution grid will be a “grid of grids,” with introduction of standard operations for VPPs, microgrids, meshed networks, and predictive reconfiguration. Distribution operations will incorporate increased visibility, automation, and distributed resources, as well as data-driven technology enabling assisted decision making in case of grid incidents. Controls will be predictive, preventative, and faster than real time. Decision making will be far more automated, decentralized, and responsive to both global and local conditions than is the case today. The primary role that humans will play is outage dispatch and reliability coordination. Management of voltage, loading, etc. will be automatic, with self-healing features. Visualization of this network at the transmission operations level will be purely data driven, with far more information than is available today. Transmission operators will have access to predictive capabilities for distribution, which could function like a large distributed VPP, a network of microgrids, in combination with traditional radial feeds. The state-estimation tools required to make this configuration possible will be driven by AI, which can determine the potential service, load, generation, and events at each node, and develop those data into information that an operator can manage. These distributed resources will actively participate in new market structures and perform automated optimization that balances multiple priorities.

One of the longer-term needs as both the transmission and distribution systems evolve is the integration of decentralized operations. One perspective is that the nature of decentralization means that the operators at the bulk system level do not need to have any view of distribution system operation, i.e., the system should run as-is, with distributed or central controls at the distribution system level that are likely to move significantly faster than human operators. The target is a self-healing system that is safely reconfigurable with a reduced need for field crew deployment. To realize consumer benefits, the distribution system’s impacts on transmission operations, and vice versa, must be understood using analytical and data-driven techniques. Model-based controls with connectivity-driven responses will not necessarily provide dispatchers at the transmission level with useful information. Non-radial, rapidly reconfiguring distribution configurations will impact the transmission operations level, changing controllability and observability at the main supply nodes.

Figure 2 illustrates the vision of the future integrated T&D operation and market environment. To support the vision, transmission and especially distribution will be upgraded significantly to support wholesale and retail transmission operation and electricity markets. The information infrastructure will make data and information available, observable, and controllable. Traditional utility distribution operating centers will support transmission operation taking on the role currently played by distribution system operators. To this end, data and an architecture for implementation of advanced analytics and

ML techniques for actionable intelligence will drive fundamental change in the operational environment. An information layer driven by faster-than-real-time computation will provide operators with intelligent operational system status updates.

When T&D operations are integrated, stakeholders will include loads (customers), DER owners, the utility as a reliability coordinator, and market operators.

At the transmission level, stakeholders include:

Wholesale market operator: At the transmission system level, generation and load agents submit bids, and market-clearing algorithms determine the energy and ancillary services to be provided by the agents in day-ahead or real-time markets. Recent FERC Order 2222 removes the hurdles that DER in the distribution grid previously faced to participation in transmission-level wholesale markets.

Independent system operator (ISO): Large interconnected transmission systems provide the infrastructure for delivering bulk power from power plants to the loads. Reliability, cyber security, and resiliency standards are established by federal and state agencies and standards-setting bodies.

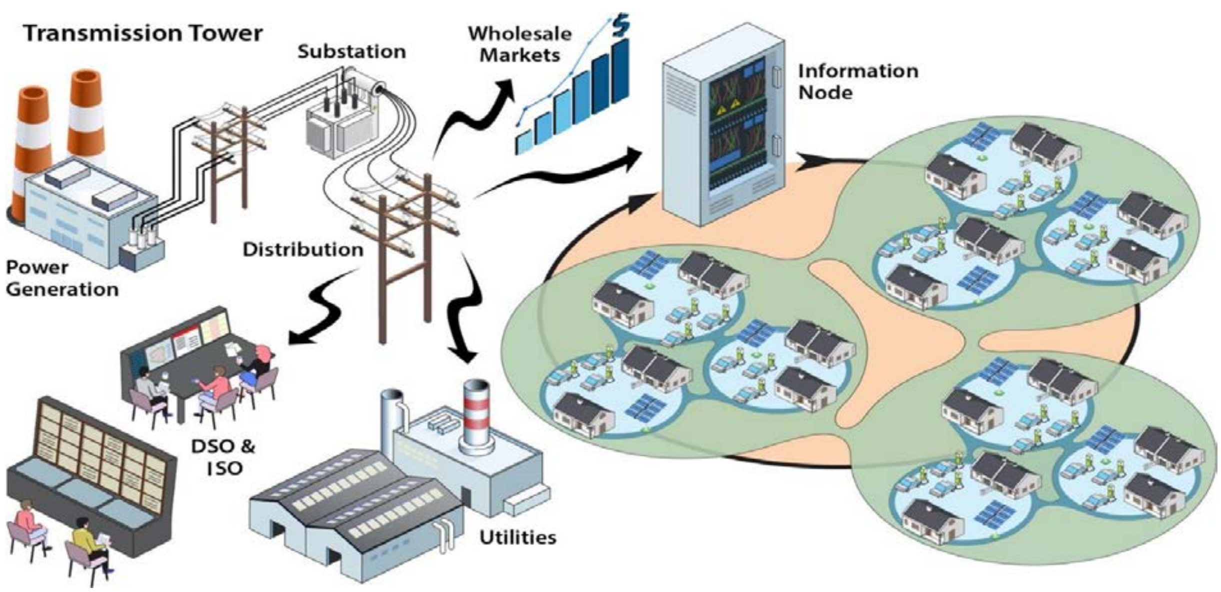

Figure 2: Vision of future integrated T&D grid operations

The roles of stakeholders at the distribution level (customers, DER owners, retail markets, aggregators, and utility distribution systems) are discussed in Section 3.1 of this paper.

Having explored in Section 2 the drivers for change on the transmission and distribution systems, we now look ahead at the next 20 years of transition to the new vision. In the subsections below, we identify the elements of the vision for the future integrated T&D grid and link them to the drivers described in Section 2.

3.1 Vision of Transmission and Distribution Integration

The subsections below describe the vision for key areas of the integrated T&D system in 20 years. Each element of the vision (V1, V2, etc.) is numbered to indicate the driver from Section 2 to which it relates (D1, D2, etc.)

D1: Expected exponential increase in DER and renewable generators; retirement of traditional assets	→	V1: High penetration of operational DER will provide collaborative and coordinated support to both transmission and distribution operations; major assets will be retired.

D1-V1: In 20 years, distributed resources will serve a significant percentage of the distribution system. Renewable resources will achieve high penetration in certain areas of the country, and advanced technologies for distributed resources will be used to balance the system and will have day-ahead forecasts within 5-10% accuracy. There will still be bulk power transport, but it will be coordinated with the distributed and stochastic features now commonplace on the lower-voltage network. Utility companies and third parties, including utility customers and prosumers, will be able to own DER.

D2-V2: In 20 years, electrical energy and ancillary services will trade at both the wholesale and retail levels. New retail transactive energy mechanisms will be established at the distribution level, allowing DER to conduct bilateral trading. The distribution utility system, in its role as reliability coordinator for the market, will develop and operate ancillary services, such as voltage control and resilience services, that will be provided by DER. Integrated transmission and distribution systems will coordinate the wholesale and retail markets. In this future vision, there will be a shift in management and market activities that will affect distribution system operation and control.

D2: Need and desire for non-wire yet operational alternatives with market participation features	→	**V2:** Non-wire alternatives will be considered commonplace, with new markets to enable these alternatives.

As fixed boundaries are removed and a new "meshed" distribution operations system emerges, control time frames will also decrease, and it may be possible for large clusters of entities functioning as active generators or loads to provide transmission support to prevent outages. Automation and a grid of grids, or networked microgrids, will become a common feature, and transmission operations will need data and analytics to monitor these distributed resources. Nodal forecasting and reporting will be necessary along with decision support tools for both operators and consumers.

Optimization of DER, reliability, and resilience from both the bulk and distribution perspectives is a challenge. While the number of customers impacted by transmission decisions will be much larger in this future vision than will be affected by distribution operations, decentralization on the distribution side will lead to much greater choice for the consumers.

The distribution operator, when functioning as a reliability coordinator, will also be considered the data concentrator for information on component-driven performance. Handling distribution operations data delivered from nodes whose condition can morph on a sub-second basis will require a transformation in perceptions about data delivery, decision support, distributed resources, and decentralized controls.

In addition to the existing centralized wholesale market, there will be future decentralized, bilateral electricity market mechanisms for DER and flexible loads. A transactive energy environment will be fully enabled on the distribution system, and utilities, third-party owners (renewables, DER), and consumers will participate as both players and stakeholders. As noted above, the distribution system will play the role of reliability coordinator for its operations, which will be optimally integrated with transmission operations. It is anticipated that ownership by multiple players will make distribution operation and planning more complex than it has been in the traditional "vertical" structure where transmission and distribution utilities own, operate, and maintain the power grids.

D3: Availability of, and need for, information for both operators and customers	→	**V3:** Information on demand is available; decision-making support for consumers and operators is optimized for best outcomes.

D3-V3: DER and loads will be required to share data necessary for maintaining distribution system reliability and resilience. The reliability coordinator will be responsible for cyber security and data confidentiality. In this paradigm, customer privacy will be maintained even as analytics provide immediate, essential, actionable information. A suite of technologies will enable local information exchange, securing the lower-voltage operational layer and controls as they react to local conditions without requiring full dispatch information. The smart meter deployment trend will continue but with significant functionality upgrades to enable the dynamic operational future described here. Smart meters will enhance outage reporting capabilities and collaboratively diagnose certain distribution conditions, such as nodal voltage rise.

Sensing devices and measured data will be essential in the future grid. Affordable yet accurate sensing can be deployed throughout all layers of the distribution system. The evolution in the future transmission and distribution system of rapid, accurate transmission sensing devices, arranged in multi-modal sensing layers to form an information system environment, gives an indication of the evolution in store for sensing and measurement on the distribution side.

An enhanced information and data layer, referred to as the distributed information system (DIS), will be an enabling technology for an integrated distribution and transmission environment. This layer will acquire data and information for appropriate parties to use in planning, operation, protection, and electrical energy trading. Because this environment will encompass distributed ownership by various parties, there will need to be clear definitions of what constitutes proprietary information as distinct from information shared for operations, planning, and transactive energy markets. Each party's responsibility for ownership, sharing, privacy, proprietary information, and cyber security must be clear.

Data ownership will be negotiated and supported in the future suite of utility services that will be enabled by enhanced sensing.

On the load side, the number of clusters of data centers will increase rapidly, and these customers will demand high-power-quality service. In the future integrated T&D environment, the grid will able to provide very high-reliability and high-quality power. Even as the large-scale deployment of inverter-based energy devices continues, the future integrated T&D grid will be able to meet the power-quality, fault current, ride-through, inertia, and other technical requirements of future generation and load.

D4: Maturity of analytics technologies in relevant fields → **V4:** Hybrid human AI environment with extensive distribution support

D4-V4: In the future grid, decision making and prioritization will be based on optimization, not perception, maintaining reliability and resilience while maximizing customer benefit and meeting customer needs. Prioritization could be guided by a set of rules, and controls on the ISO/DSO boundary should be fast enough that humans in the loop have sufficient time to take action in response to changing operating conditions. Wide-area automated actions can be balanced by automated local actions. Negotiation and optimization of these actions is a decision-support task that entails weighing impacts and benefits. To realize this future vision, ML and potentially additional AI-driven agents will be needed along with more detailed monitoring and measuring than is done today, and along with use of computationally efficient operational tools.

The transition to using ML in the medical field gives us a guide to what might take place on the power grid. In medicine, robotics and ML-driven diagnostics are becoming increasingly common. To facilitate this transition, a set of trusted experimental approaches was used in test lab environments, with rollout to research hospitals and advanced facilities. Once successful application had been demonstrated and efficiency gains proven, there was a rapid increase in technology capabilities and adoption rates, leading to new opportunities. In the domain of power system operation, physical and cyber security concerns are a limitation, as is the need for field validation and trust building [31].

Some power grid features that could be enabled by ML and AI in the next 20 years include:

- Integration of decentralized distribution system operation with transmission grid operations
- Integration of distribution system monitoring, operation, control, protection, and recovery with transmission system operation
- Decentralized controls, self-healing distribution grids and microgrids

Humans are not removed from the loop in the vision of the future grid. The vision is hybrid, with humans leveraging the power of ML without surrendering control. With integration of algorithm-based decision-making processes into utility operations, AI-ML tools will need to be fast and accurate while delivering a suite of choices and rationales to operators.

D5: Need for advanced communications and information availability → **V5:** Secure public/private data networks

D5-V5: Communications networks will be ubiquitous in the grid of the future. Tools will be in place that allow for planning and operations of the integrated T&D environment. Remote communications technologies will evolve that enable secure layers of coordination for local, peer-to-peer, reliability coordination, consumer, and utility operations communications. The communications network will be able to utilize the full spectrum and will be scalable and flexible enough to accommodate the fast-moving architectures of the future. From the outset, the system will need to meet remote and central needs for communications from sensing devices for all new distribution and transmission developments. Secure, authenticated, and continuously monitored communication networks will be commonplace to enable the future control environment that is envisioned.

D6: Stakeholder engagement and a changing workforce (including changes in decision support) → **V6:** A new workforce is trained to interact with new hybrid AI environments.

D6-V6: Consumer or prosumer engagement will grow across the country as the future grid evolves and data become available as a service, and new DER will be utilized in emerging markets and energy efficiency. Utilities' effective communications about the benefits of these new approaches and efficient rollouts of these services will facilitate growth. Consumers will optimize their societal and financial benefits by participating in decisions about how they receive, or support their own, energy generation. Load-control programs will be cost effective for consumers, who will participate in outage prevention and restoration and recovery efforts.

D7: Security and resilience in changing threat and risk environment → **V7:** The integrated operational environment is secure and can respond to evolving threats in an automated way.

D7-V7: In the future, electricity service restoration procedures will make use of DER. Because distribution feeders will no longer have a radial configuration and will include microgrids and renewable resources, restoration procedures will be significantly more complex than they are today. For traditional radial distribution systems, a rule-based, "fuzzy logic" system can provide effective decision support for distribution operators [32]. In the future meshed distribution system configuration, operations will be able to handle multiple electrical islands (outage areas), using available microgrid and DER resources to pick up and support critical load [33]. As the transmission and distribution grids are restored after an outage, these islands will be able to return to being served by bulk utility sources. The resulting complex restoration process will require status assessment, personnel safety considerations, and optimal use of limited resources, with the goal of minimizing restoration time. New decision-support tools will be required to enable the process.

Machine-to-machine automated responses and cyber-driven sensing will be integrated to address known and unknown threats. This will require analytical procedures that can distinguish among physical and cyber threats, grid events, and automated distributed actions to protect grid health. Command and control verification and data validation will be performed locally and in a decentralized manner using ML and analytical techniques. The system will need to be responsive to events from the entire network and equipped to perform forensic assessments prior to recovery actions. Cyber and physical operations supporting recovery and restoration after an event will be managed by both humans and a suite of tools.

A final consideration for a joint T&D operations interface is what is needed for large-scale restoration processes in the face of new threats, challenges, and resource availability issues. Several current pilot projects use new DER grid-forming capabilities, DERMS, ADMS, and microgrids to assist with black start. To enable future decision support for high-consequence yet low-probability events, the communications framework will need to be enhanced, with new technologies integrated in both transmission and distribution. New tools that become available should be used not only in special circumstances but also in everyday operations to ensure that the grid can rapidly recover from new threats.

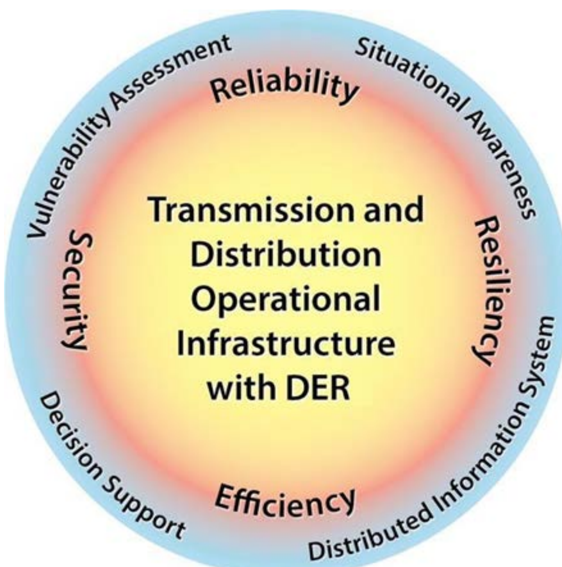

Figure 3: New integrated structures

The core vision shown in Figure 3 is of an integrated T&D operational environment, which, as discussed earlier, will be essential because of the rapid penetration of DER and microgrids on the distribution system. Integration of T&D is critical to allow energy and control resources in the distribution system to support transmission operation. The integrated T&D system needs to provide high-level reliability, resiliency, security, and efficiency, which will be enabled by DIS technologies and advanced decision-support tools that perform on-line vulnerability assessment and provide situational awareness.

From a societal point of view, one value of the specific elements (V1–V7) of the overall vision described above is increased incorporation of renewable energy and resulting reduced environmental impact. V2 provides non-wire solutions to avoid/delay grid expansion and reduce environmental impact. In V3, the availability of information on DER and loads enables optimization of energy resource utilization and allocation. The emerging ML and AI technologies envisioned in V4 improve decision making for both the grid and consumers. V5 envisions widely available communications with high-level cyber security and privacy protection for consumers as well as grid participants. V6 envisions training and development of a future workforce that can work with and harvest the benefits of new hybrid AI tools. Reliable and resilient electricity service is highly critical for society; V7 is a major step toward establishing the technological foundation for achieving this goal.

3.2 Barriers to Realization of the Vision

Next, we discuss barriers to implementing the vision described above and identify research, development, and implementation tasks necessary to addressing these barriers. The future vision can be categorized according to its drivers, but the barriers to the vision extend across these categories. Therefore, we organize our discussion of the barriers in terms of their own set of categories: technology, regulatory, and societal needs.

3.2.1 Technical Barriers

Technical barriers can be subdivided into the following categories, each of which is addressed in its own subsection below:

- Sensing, measurement, communications, and analytics barriers
- Tool-related barriers
- Access to data for research purposes

3.2.1.1 Sensing, Measurement, Communications, and Analytics Barriers

One key barrier to realization of the future integrated T&D grid is the availability of data to enable centralized, coordinated control. We need to determine what information must be available to enable the combination of technology and human input to achieve its greatest potential. Decentralized controls will be enabled by ML and AI, as well as high-performance computing, storage, and cloud-based systems, but a transmission operator must be able to safely manage a system in which decisions must be made in the face of competing priorities. Changes to human-machine interfaces will be needed to create trusted, secure systems that operators can use to understand how the distribution system's behavior will affect the transmission system or what opportunities are available to manage distribution operations.

The primary barrier to integration of ML and AI will initially be in the human realm, but there will also be barriers to overcome in the areas of communications, distributed computing, and security. Sensing and measurement constitute a barrier in the sense that there are major integration issues with the information and communications technology and analytics needed to make use of measured data, and there is no systematic methodology for distribution systems to move toward an integrated information and communication system that will provide full observability of the distribution grid in the long term.

Another challenge is the cost-benefit analysis for distribution sensors. Economies of scale that apply to transmission applications do not apply on the distribution side, and distribution budgets are not sufficient to fund the sensor network that is needed. Moreover, communications, security, and integration challenges are not accounted for. Distribution PMUs' proven benefits make them a strong candidate to be used on the future grid [34]; however, PMUs are not widely deployed on the distribution grid. The barriers to their deployment are cost, difficulty of installation, and the lack of available communications through a secure utility network. The security issue has been addressed in research projects using secure cellular communications, but there is no central plan for applying this solution, and not all sensors incorporate the appropriate technology to communicate in this way. Generally, with new types of sensors, each silo of sensing technology seeks to address every problem, e.g., a specific sensor type will try to make use cases for many different systems but will not be designed with the security and communications plan necessary to do so. For example, in some cases, sensors (e.g., the Sentient [35] devices) have been deployed with built-in communications that were designed to use only proprietary cloud and analytical infrastructure. Although extensive work on interoperability has been conducted by the National Institute of Standards and Technology and other industry groups [36], interoperability is still lacking for data, sensing, communications, and analytics in this area.

Network speeds that cannot support integrated analytical capabilities also pose a key limitation, and another challenge that must be considered is the balance between privacy and data availability. As the United Kingdom has experienced, deregulation and the newer regulatory environment for data, although beneficial from the consumer and legal perspectives, has led to operational challenges and loss of data value streams. Smart meter data, governed by a different entity than the system operator, is not available in real time in the U.K., nor are those data available for building new business models. In short, there are barriers to full utilization of this advanced data source. Lessons learned from sensing technology deployment in other countries should be applied in the United States.

3.2.1.2 Tool-Related Barriers

Situational awareness aims to provide an accurate assessment of power system security in the presence of contingency events, equipment failures, and the rapid variations and intermittency of renewable energy resources. Vulnerability assessments determine the likelihood and potential impact of contingencies and threats. Currently, decision-support tools for distribution system situational awareness and vulnerability assessment are not integrated with distributed resources or with the transmission operations environment. Integration of data into situational awareness has been piecemeal, and visualization of forecasting and sensor data is often perceived as overwhelming or confusing.

State estimation, and, in particular distributed state estimation, has been widely discussed, but full-scale integration of an operational environment that accounts for decentralized resources is not yet possible. R&D is needed on observability and state estimation of distribution systems. One important R&D issue is the resolution in time and space of the data needed; however, this issue is not part of the focus of this paper.

In studies of scenarios where remedial action is needed on the transmission system (for example when a line is overloaded) all load served from a transmission substation is often lumped into one (megawatt and megavolt ampere reactive) at the substation, but, in reality, the load is often served by various distribution feeders that start from the substation and go to the load areas. If a load needs to be transferred from one substation to another to relieve an overloading condition, the amount of load to be transferred to various feeders must be determined before the transfer occurs. Consistent network modeling are needed, with adaptive constraints for decentralized controls, to maintain the feasibility of operation and control in both transmission and distribution systems, including for remedial actions such as described here.

Communications networks are limited by the ability to effectively plan for them because planning tools (or a distribution communications planning function) do not exist or are in a research-grade form only. There has been significant work in this area, using new simulation tools, but operational planning for a new communications network is not yet possible. Limitation on visualization and operation of communication networks is a barrier to wide-scale deployment, which is also linked to the first barrier in communication technologies.

3.2.1.3 Barriers to Access to Data for Research Purposes

Another technological barrier is access to data for R&D. Currently, data are often not made generally available; within national labs, industry, and academia, access to data sets is often moderated by partners on projects. Energy delivery information is protected by various means, including Critical Energy Infrastructure Information regulations [37], North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection [21], and Personally Identifiable Information protections (in the case of smart meter data). Research should explore how to meet security needs and provide greater access to data sets. Institute of Electrical and Electronics Engineers models [38] and prototypical feeders have significantly pushed boundaries in this area but have not continued to develop; new generations of these models are needed. The DOE Grid Modernization Initiative and DOE Advanced Research Projects Agency–Energy [39] did some work addressing this issue, but lack of widespread access to data sets representing operational conditions remains a key barrier.

3.2.2 Regulatory Barriers

Market mechanisms will be needed as distribution companies, consumers, DER owners, and regulators explore future opportunities in electric energy. Although FERC Order 2222 is a major step to reduce the barriers for DER to trade in wholesale markets, there is generally no DER market mechanism at the distribution level. The mechanism discussed in Section 3.1 for DER to trade electric energy and ancillary services in future markets will be critical as an incentive for long-term growth of DER connected at the distribution level. However, there are obstacles to developing such a mechanism. Microgrids' regulatory requirements are unique, their ownership models are not clearly defined, and networks of microgrids that have different owners pose a challenge. In addition, the regulatory process for electricity markets is complex. At the federal level, FERC is responsible for interstate commerce for wholesale markets managed by transmission market operators. Investor-owned distribution companies are under state regulatory commissions. Municipal power companies operate under municipal governments made up of elected mayors and councils.

Distribution systems will in the future move toward having DSOs, which will function as reliability coordinators, maintaining not just reliability but also security and resilience as trading markets for DERs are established. Here the role of a DSO is analogous to that of an ISO in the wide-area transmission grid. The DSO is not an owner but an independent entity that operates the distribution network to maintain system reliability while supporting electricity market operations. The experience of setting up wholesale electricity markets suggests that there are legal issues concerning how DSOs will be independent grid operators in a market with numerous supply and demand agents. There is also a gap in technology to enable distribution utility systems to operate as DSOs. Existing DMSs or ADMSs generally do not have the capability to perform on-line power system security assessment, which will be important for DSO situational awareness and vulnerability assessment. Many small utility systems have SCADA monitoring and control facilities but do not have DMSs or ADMSs. Regulatory barriers have to be removed to equip DSO reliability coordinators with the tools and capabilities they need. The reliability/security/resilience requirements for the DSO market environment will need to be studied and expanded to address future operational scenarios.

It is important for regulatory bodies to be informed about the balance between reliability and consumer costs. From a narrow view of return on investment, distribution investment tends to be low. Cost of long-term outages is often balanced against safety cost, but there are currently limited metrics for true valuation of resilience services.

3.2.3 Societal and Workforce Barriers

A growing workforce gap in utility and grid operations constitutes a barrier. Training a new workforce for an integrated T&D system will require new tools and simulators for future configurations of the operations environment. Educational needs extend to society at large; consumers also need to be informed and educated about the concept, technology, cost-benefit, and risks of markets, including demand response and smart meters. Research on socio-economic issues is needed to develop consumer education programs.

Workforce development is an important recommendation of this white paper. Educational, training and development programs need to be developed, tested, and implemented for grades K-12 and universities and colleges, as do industry workforce training programs and outreach to society at large. Promoting diversity through proactive outreach to female and under-represented groups is important. Within the workforce, the traditional utility engineer model will change, with a growing need for workers who are trained across multiple disciplines, including data, communications, and automation/control. New apprenticeship programs that do not necessarily require a four-year degree must be developed to support this future workforce.

To engage and energize the future workforce, it would be useful to develop open-source software communities so that, in the next generation of workers, software skills are more common, and tolerance for antiquated software solutions is low. Vendor-driven innovation is rare and costly. Micro-innovation in the form of “citizen-developers'' may be an attractive, creative approach. The industry cannot attract tomorrow’s talent and leadership with yesterday’s technologies. It is important to change the mind set and encourage eagerness for creative technology development. The industry may brainstorm new control room tools by offering summer internships that bring in a younger generation of workers who have computer science and gaming skills. Furthermore, where possible, talent from national labs and universities should be embedded in utilities and manufacturers.

Cost can be an obstacle to utilities’ adoption of new technologies, particularly in disadvantaged, remote, and rural communities. It is important to consider social justice in developing future operational structures.

Complexity of new programs/technologies can be a barrier to customer participation and must therefore be minimized to enable consumers to participate effectively. It is also important to keep in mind that consumers generally do not favor day trading of energy usage. Reliability should be the priority from a consumer’s point of view.

As mentioned earlier, many operational changes have occurred during the past 20 years, and a large proportion of the technological change has been in response or reaction to an event rather than proactively implemented. In discussions of future approaches to events that have not yet occurred, such as high-consequence yet low-probability storms, one often hears the perspective that a utility cannot anticipate investments until an event has occurred. Ingrained habits and perspectives are barriers to making prospective technological changes. Technology cannot address the issues proactively, without a clear demonstration of its capability during these events.

3.2.4 Economic Barriers

There are economic barriers to the realization of the vision of an integrated T&D grid. Transactive markets that enable trading of energy and services create incentives for large-scale deployment of DER. Operation of these markets must take grid reliability into account, which would require reliability coordinators for the distribution system similar to the reliability coordinators that already function on wide-area transmission grids. Forming reliability coordinators at the distribution level would require significant investment. It is also important to consider whether the distribution system configuration may be vulnerable to market power. In the current radial configuration of distribution systems, an agent could cause congestion on a distribution feeder by intentionally lowering prices, thereby preventing other agents from trading on the same feeder.

As the vision of the future grid is being developed, it is important not to neglect low-cost or low-tech technology options that may be just as effective as more costly options. For example, underground distribution systems are proven to be reliable, but their cost is high. The option of undergrounding should be compared, in terms of costs, reliability, and other relevant considerations, with options to improve overhead distribution infrastructure. Improvements to operational infrastructure must also balance cost for all consumers, and operational changes should not decrease energy access for any class of consumer.

4. Architecture and Targets

The proposed architecture for operation and control (as well as planning, protection, and maintenance) of the integrated T&D grid has five layers, each of which supports elements of the vision for the future grid, which were outlined in Section 3:

1. **Enhanced Data/Information** (supporting Vision V3: Information Availability, and V5: Communications)
2. **Data Analytics and Protection/Control Technologies** (supporting Vision V1: High Penetration of DERs, Vision V2: Non-wire Alternatives)
3. **Grid Decision Support Environment, Tools, and Communications** (supporting Vision V4: Hybrid Human-AI Environment)
4. **Operators and Control Centers** (supporting Vision V6: Changing Workforce)
5. **Cyber Security and Privacy** (supporting Vision V7: Secure Integrated Environment)

Figure 4 illustrates the five layers. The critical technology solutions that are needed for each layer in order to realize the vision of an integrated T&D operational environment are discussed in this section.

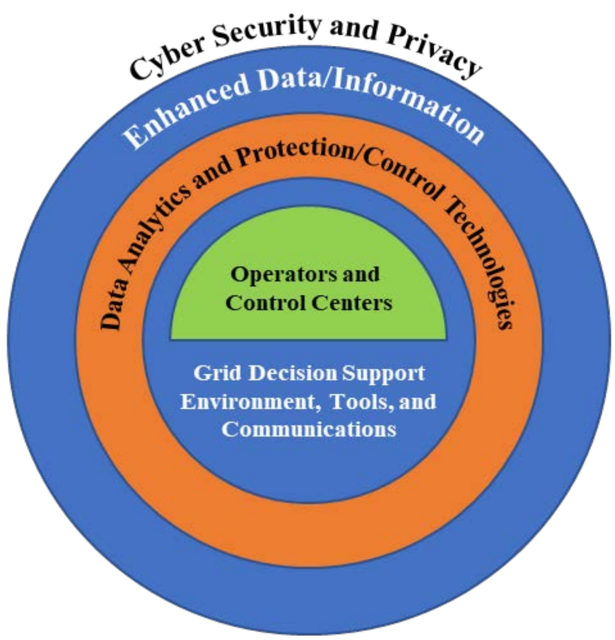

Figure 4: Layers of integrated T&D grid architecture

In the description below of the layers of the architecture, we include some discussion of targets for developing the components of the layers. The discussion of targets informs and points to the R&D recommendations that are presented in Section 5 of the paper.

4.1 Enhanced Data and Information

An enhanced information and data layer is an enabling technology for the distributed transmission operations environment described in Section 3. This layer is concerned with data and information acquisition by appropriate parties for operation and protection of the grid as well as and energy trading. The information and data layer would replace or significantly enhance current enterprise bus data architecture. As noted earlier, in an environment where ownership is distributed among various parties, proprietary information and shared information for operation and transactive energy market must be clearly defined and maintained. There should be standard definitions for each party's responsibility for ownership, sharing, privacy, proprietary information, and cyber security. Technical challenges in this layer, including maintenance of those standards, will be addressed through creation of the DIS.

Target performance for the distributed information system layer is to securely combine all potential measurements in a multi-modal, multi-variate environment that preserves privacy while allowing for connection of an interoperable suite of sensors and analytics available to both reliability and transmission entities. Predictive, real-time, and historical applications would aim to provide 100% visibility of the distribution system. Latency of sensing and communications would need to meet the requirements of the predictive and control side, with data flow as the highest priority, and latency set at the lowest level exhibited by the next layer of data in the near real-time field. Latencies of up to minutes would be considered reasonable. These data would be utilized in optimization and state-estimation operations. Historical data requires latencies that range from more than a few minutes to days and are used primarily for markets, forensic analysis, and asset management. The longest latency requirements are for data required for planning, compliance, and risk analysis. In some cases, real-time feeds from grid sensors are needed; in other cases, processed historical information is needed. Communications systems must be adaptive, scalable, and secure to meet these varying needs.

The R&D recommendations in this paper include a recommendation for a comprehensive, holistic study of the sensing and integrated communications needs for the transmission and distribution interface. The results of this study should include the specific data to be shared; networks used for transmission (radio frequency, cellular and/or fiber); time scales of data delivery; hierarchical structure (central or distributed); and performance, fusion, and latency requirements. The goal is to provide the data required by optimization and ML and AI tools.

4.1.1 Sensing and Measurement

In the future, distribution PMUs, analog/status measurements, protective devices, and fault indicators should be integrated within the same information and communications system. Multi-modal data systems should also be integrated for full observability, including graphical data. Multi-modal data can include data from sensing devices that are neither stationary nor connected to the architecture, e.g., from unmanned aerial vehicles and other remote monitoring technology. Light detection and ranging (LIDAR) and weather data should be integrated directly with operations. Integrated information/data will serve as input to advanced outage management and service restoration functions. The current communication subsystems will evolve into a networked DIS, which will require operational distribution sensing to enable forecasted and real-time capability assessment of distribution nodes that will be perceived as more than “just a load.”

To meet observability requirements, PMUs and high-fidelity sensing will need to be installed on a set of nodes in the distribution feeders. Cost-benefit and cost-reduction strategies are implemented in the future model, in which sensors will be optimally placed and accessible. Measurements should include voltage magnitudes and angles and current magnitude and angles with time stamps at each node. In the event of an open- or a short-circuit fault, the currents and voltages will be recorded to enable the detection and location of the fault and possible malfunctioning or failures of the devices. Devices must deliver high accuracy, low latency, and reliable security while also being affordable for ubiquitous deployment to support the new data-driven model.

At each of the nodes, SCADA systems will acquire status and analog data. A node may or may not have an advanced sensor. Measurements should include voltage magnitude at each node and current magnitude on each line, as well as for each of the three phases connected at the node. Status data should include on/off state of the breaker, switch, or recloser at the node.

Fault indicators identify overcurrent and flag short-circuit conditions. The flags should automatically be sent to the remote operating center where outage management is performed. Information can be enhanced, using on-board analytics, to include causation and time-to-failure.

Information systems in the distributed environment will be coordinated using an integrated information device or a data concentration node. Similar to what is needed by phasor data concentrators, distributed information will require centralized management, and the volume of information flow will need to be closely controlled. Information systems will enable interoperability of disparate and multi-variate sources and will be extendable to the DIS layer. A standard should also be established for streaming data integration. Integrated information devices (IIDs) will enable the necessary combination of sensing technologies.

Specifications for future sensing and measurement devices, integrated with a DIS layer, were defined in the Grid Modernization Laboratory Consortium, Sensing and Measurement Technology Roadmap [37], with the goal of fast, accurate, and inexpensive devices throughout the entire distribution and transmission system. That research considered optical transducers and dynamic fault-condition detection devices with the ability to detect a variety of parameters to within 0.5 to 1% accuracy with latency of less than a millisecond. These goals would support development of the future integrated system envisioned in this paper.

Research should continue on low-cost sensors and multi-modal data collection. Embedded and public-domain sensors should be considered. Partnerships between utilities and commercial/industrial sectors may be a viable approach to providing monitoring as a service. In an environment with distributed ownership, the data/ information needed by each party regarding operations, control, and the market must be defined. R&D is also needed on calibration.

4.1.2 Distributed Information System

The DIS is a networked environment containing numerous IIDs. Each IID is a combination of sensing, measurement, and analytics technologies and performs a multitude of functions to provide measurements of, and status information for, different elements of system operation, control, and protection. IID design and capability depend on the device's installed location and power/voltage levels, as well as other identified functions. IIDs are expected to be deployed at substations, primary feeder/laterals, DER, and other locations with significant load. Smart meters at customer locations should also be linked to the DIS through networking. Deployment should be optimized according to the operations communications and security framework. Measurements should include voltage and current during normal and faulted conditions with synchronized time stamps. Through the networked environment of a DIS, IIDs can share measurements, status information, and fault indicators with other IIDs and potentially with SCADA nodes in the network. This is a significant extension of existing communication capabilities in relation to existing SCADA and smart grid functions. As shown in Figure 5, the DIS in an integrated T&D system serves as a large-scale, networked information infrastructure for communication, operations, and control.

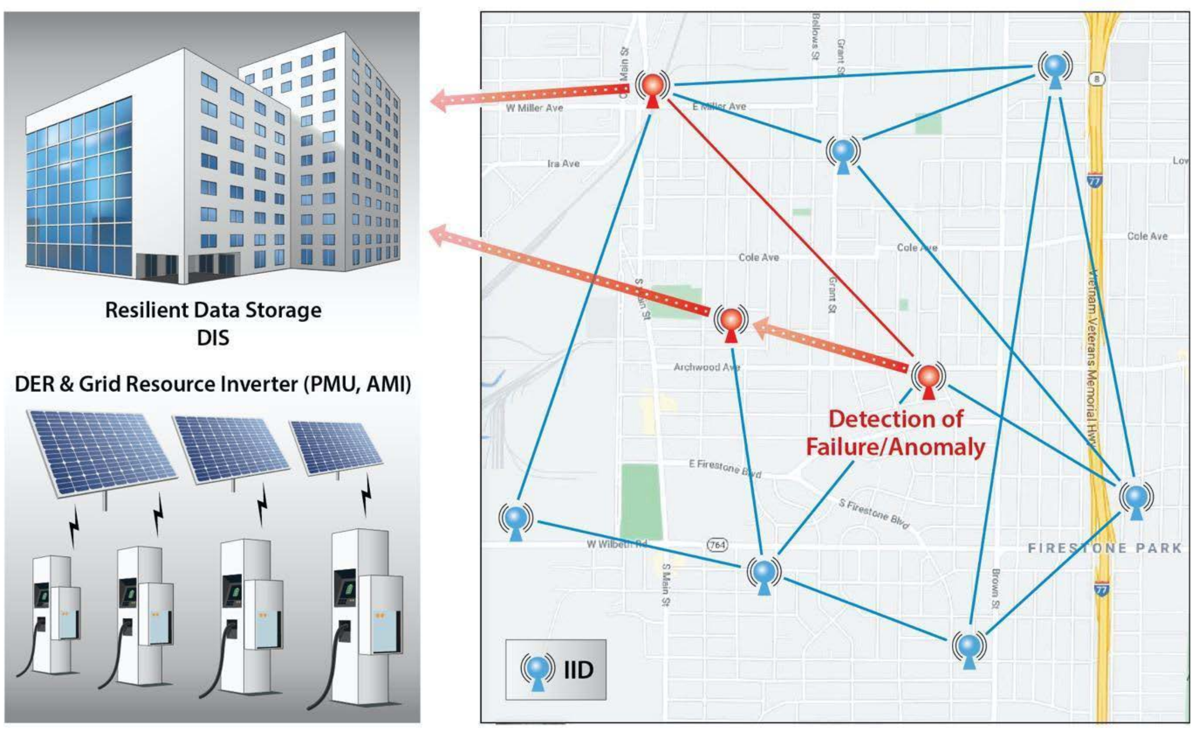

Figure 5: The distributed information system enables peer-to-peer and centralized management

Table 1 lists the data to be acquired by the proposed DIS and IIDs along with the responsible parties. The DIS will provide the data and measurements for operation and control, outage management, and service restoration. Smart meters and smart devices, such as EVs, will be enabled to participate in the energy and service trading markets. The market data and DIS will be networked so that trading and reliability decisions can be made to support market operation.

Table 1: Distributed Information System Data and Communication Capabilities

Locations	IID Measurements, Information, and Communication Capabilities	Responsible Party/Parties
Distribution Substation	High-fidelity voltage/current/power measurements via SCADA, optical transducers	Distribution and transmission utility
Primary Feeders and Laterals (medium fidelity, higher latency, distributed analytical capability)	Voltage/current phasor measurements at selected nodes (by PMUs); low-cost, multi-parameter sensing, distributed analytical nodes	Distribution and transmission utility
Primary Feeders and Laterals (automated & controlled, medium fidelity, medium latency)	Feeder remote terminal units (or networking communications) at selected nodes; include smart switching/control devices under remote monitoring and control, power quality and harmonics	Distribution utility
Primary Feeders and Laterals (automated, low latency, high fidelity)	Fault indicators with remote monitoring capabilities at selected nodes; sufficient capabilities to detect faults and configuration for various locations/types; protection monitoring	Distribution utility
Distributed Energy Resources (e.g., solar photovoltaic, wind, storage, flexible load, EV providing ancillary services)	Status, voltage/current measurements (PMUs, smart meters/devices)	DER owners (utility and non-utility), Locations with large load
Non-Connected Technologies	Unmanned aerial vehicles, LIDAR, nodal weather forecasting	Distribution and transmission utility

4.1.3 Data Integration

Moving toward the vision of an integrated T&D grid will entail realizing significantly increasing data/information availability, which, in turn, will require careful design and layout of IID installation, measurements, and communications. Clear pathways and standards for integrating data into the operational environment are needed. SCADA functions, advanced sensing and distribution PMUs, and other devices will need to be integrated, with plug-and-play capability. Feeder remote terminal units (FRTUs) will provide voltage and current measurements for both normal and faulted conditions via remote-control and status-switching devices, similar to the integration of PMU measurements and

SCADA data on the transmission system. R&D is needed to enable future FRTUs that have PMU capabilities.

Currently, major research issues need to be addressed related to deployment of information and communications technology for an integrated T&D grid. A methodology for distribution systems is needed to move toward an integrated information and communication system. That system will need to provide the required long-term observability of the distribution grid. A key issue is integrating remote terminal units/feeder terminal units in distribution SCADA system with other instrumentation such as distribution PMUs, fault indicators, and protective devices. Integrating these elements will provide a powerful information system for protection and control, fault detection, outage management, and service restoration. Secure, fault-tolerant communications providing observability of all distribution nodes is the primary goal. Note that full observability does not necessarily require remote measurements from all nodes on the distribution system. Rather, full observability can be achieved by acquiring sufficient data to enable situational awareness and state estimation. Different distribution system configurations may allow for different levels of transmission system situational awareness and observability of the distribution system.

The devices mentioned above should be connected in a networked environment, replacing the traditional SCADA communication architecture in which each node communicates only with the operating center. In a distribution system with numerous DER, loads, grid devices, and controls, decentralized yet coordinated decision making is more practical than a centralized approach. A key limitation is that the current network speed is not designed for integrated analytical capability. In the future, the information and communications technology will need to allow agents (intelligent software modules with distributed decision-making capability) and devices at the nodes to share data and coordinate actions in a distributed intelligence environment. Although this topic is not the focus of this paper, we note that sufficiently secure, powerful edge computing that is integrated for this application will be a key enabling technology for the future network.

Utilities today are beginning to leverage third-party wireless solutions. In the future, the power industry must evaluate secure cloud technology services, which are supported by industrial-scale data warehouses and server farms with high reliability and redundancy.

4.1.4 Data for Electricity Trading

In the future, smart meters' roles are expected to expand to enable participation in demand response programs, transactive energy trading, and pricing incentive mechanisms, such as time-of-use and critical peak pricing. Data on a wide range of time scales will need to be provided by smart meters to support operations as well as trading functions. Operational data on short time scales (milliseconds to seconds) will be needed for power quality and voltage control. In contrast, demand response or energy/ancillary service trading can have a time scale up to minutes or longer.

As DER and customers increase their participation in bilateral or centralized electricity and ancillary service markets, meters will be needed to monitor power and energy volumes and scheduling as well as power quality (e.g., voltage sag and interruptions). Meters serving trading functions will likely continue to operate in an environment that is fundamentally separate from operations but will contribute to situational awareness through IIDs and the DIS, which will provide measurements and information for grid operation and control. The existing AMI needs to be coupled with the proposed DIS for monitoring and control purposes. (The current practice for AMI is to provide business information for billing.) New technological capabilities will gather operating information, e.g., voltage, current, real/reactive power, and outages, that will be shared among agents and the operating center when triggered (by exception or with enhanced communications for central ML-based capabilities) based on a pre-defined list of events, such as power quality violations and outages.

4.1.5 Communications Networks for Operations

Communications at the transmission system level are critical for SCADA as well as protection, control, and substation automation functions. The traditional radial links from each individual substation to the control center are already being transformed to a networked configuration that allows substations to communicate with each other. At the distribution level, communication systems can vary from optical fiber serving the SCADA system to wireless for smart devices and smart meters. For the future vision of integrated T&D operation and control, research is needed to develop a communication infrastructure that integrates transmission and distribution systems and allows for situational awareness, observability, and controllability.

The communications network will be one of the key enabling elements of the future grid. A network should be developed that is secure, affordable, fault tolerant, and able to support high-speed data infrastructure and transmit/withstand high volumes of data. The network should create links between peers, to the central data nodes (IIDs), and to the central operational layer. Business models must be developed to implement and utilize these networks. A framework must be developed that facilitates communications among planning, operations, and decision-making processes.

Key parameters that must be designed into the communications network include enabling high data throughput with very low end-to-end latency (<1 millisecond) and the ability to improve utilization of networks across different frequency spectrums. Best practice guidelines for this must be developed. The distributed communications network must be scalable – up to 10 million for the new distribution system architecture – and easily deployable for future grid architectures and new technologies as they emerge. It must also operate reliably, 99.99% of the time, support protection applications, and be secure with definition of new standards above NERC critical infrastructure protection levels. In addition to latency, other issues that need to be addressed in developing the communications network are measurement errors, redundancy, and resiliency.

4.2 Data Analytics and Protection/Control Technologies

With increases in complexity of the data obtained from sensors and a desire for new analytical and predictive tools for the operations environment, the future integrated T&D grid architecture must consider data management and interface goals. New tools for data analytics, such as power system operational security assessment and control, are needed for distribution grid analytical capabilities. The distribution system needs enhanced capability to recover from extreme events and the ability to use resiliency resources to sustain service to critical load when the utility system is not available for an extended period. These capabilities must be expanded to be multi-modal and multi-variate, leveraging progress from related industries such as defense and medicine. The information derived from the hybrid decision support environment must be close to “on demand” with very low latency, and the system must be easily maintained. Development of this analytical environment will depend on future workforce changes, such as integration of data scientists into the control environment.

4.2.1 Enabling Transmission-Distribution Cooperation

Integrated, interoperable software tools are needed to link transmission grid EMSs and distribution grid ADMSs (ADMS is expected to be a pervasive technology in the coming decades). The software needs access to real-time operating conditions of both the transmission and distribution systems. Data-sharing will enable analytics for monitoring and assessing system security. Standards-based data sharing must be implemented. Table 2 lists the monitoring and power system security functions needed for T&D co-operation:

Table 2: Monitoring and Power System Security Functions

Applications/Analytics	Technology	Responsible Party/Parties
T&D System Monitoring	SCADA, RTUs, FRTUs	Transmission/Distribution System Operators
T&D State Estimation	EMS/ADMS	T&D System Operators
T&D On-Line Power Flow	EMS/ADMS	T&D System Operators
T&D Operating Training Simulator	EMS/ADMS	T&D System Operators
Monitoring of DER	ADMS	DER Owners
DER Generation Forecasting	ADMS	Generation/DER Owners (Utility/Third Parties)
Transmission-Distribution System (N-k) Security Evaluation	EMS-ADMS	T&D System Operators
Cyber-Security Monitoring	ICT	ICT Operators/DER Owners/Transmission and Distribution Systems

SCADA = supervisory control and data acquisition; RTU = remote terminal unit; FRTU = feeder remote terminal unit; EMS = energy management system; ADMS = advanced distribution management system; T&D = transmission and distribution; DER = distributed energy resources; ICT = information and communications technology

In the future vision, DER, including microgrids, will be able to provide black-start power for the transmission system. (Note that their availability will depend on incentives for DER and microgrid owners.) For this purpose, there is a need to develop transmission and distribution paths with operational visualization for delivery of black-start power to non-black-start units and/or critical load connected to the transmission grid. Future system restoration methodologies need to incorporate a rapidly increasing volume of DER, including distributed generation, as an integral part of the strategy. We note that top-down (utility extra-high-voltage) and bottom-up (utilizing distribution) approaches tend to improve system restoration efficiency and enhance resiliency. These functions require T&D on-

line state estimation and power flow to ensure that technical constraints are not violated.
New data analytics tools, such as power system operational security assessment and control, are needed for the distribution grid. The goal is to provide distribution systems with the capability to use resiliency resources to recover 100% of critical services when extreme events render the utility system unavailable for an extended period. As renewable energy resources are deployed at large scale, generation forecasting will become more important.

The target is to enable power dispatch on a day-ahead basis using forecasted renewable generation at numerous nodes. At a minimum, each distribution substation node should be forecasted day ahead with high accuracy and measured/reported to the operators in real time in a manner that is integrated with advanced decision support. To support transmission operations, R&D is needed to enhance DER generation-forecasting capabilities, especially for wind and solar generation, aggregated at the substation level. Furthermore, as wholesale and retail markets develop at the distribution level, generation and load agents on the distribution grid will need to have the market decision-support tools to allow full participation in demand response, bilateral energy contracts, and ancillary service markets. For example, at the distribution level, software tools for ancillary service markets are needed to provide incentives for DER, including energy storage and EVs, to participate in voltage control. Demand and supply agents can be enabled to conduct auctioning and bidding, respectively, in a transactive energy environment using new optimization tools to quantify cost, benefit, and risks based on each agent's interests.

On the distribution side, R&D needs include computational tools to use SCADA/ distribution PMU/multi-parameter data to identify violations of distribution system operational constraints. In addition, SCADA/distribution PMU data can be used to estimate three-phase voltage phasors. Note that distribution systems normally operate in an unbalanced condition among the three phases. Distribution state estimation is needed to calculate the voltage phasor for each of the three phases in the presence of noise or measurement errors. Predictive analysis needs to account for distribution system and DER topology and configuration.

4.2.2 Protection and Control Technologies

Traditionally, distribution systems are protected by a combination of (monitored) breakers, monitored or unmonitored reclosers/sectionalizers, and unmonitored fuses. The nature of the protection depends on the importance of the location along the feeder and the load it serves. For the future vision described in this report, protection strategies will need to evolve; for example, microgrids with DER may rely on differential protection because of their multiple sources and the resulting meshed configuration. A future protection system should be able to report operating conditions and tripping events to the operations center. New analytics will be needed that can determine fault/failure scenarios and reconstruct the sequence of events leading to a fault, to support outage management and service restoration tasks that are not automatically possible in a self-healing system. New forms of protection must account for consumer and line worker safety and be configurable to allow manual and automated de-energization during different types of events.

Smart, remotely monitored, automatically controlled breakers/switches will enable the meshed distribution environment and will also be integrated within the DIS environment so that these devices' status is constantly updated. Similarly, remote-controlled reclosers will be integrated within the DIS environment so that the status and operating sequence of these devices is constantly updated. The combination of sensor data from these devices will contribute to nodal estimation efforts that must be incorporated in distribution operations.

4.3 Grid Decision-Support Environment, Tools, and Communications

In the integrated transmission and distribution system, extensive data acquisition and increased control capabilities, such as smart switches and other devices, will provide situational awareness that will, in turn, enable distribution systems to provide information that will be valuable to the transmission side of the integrated operation.

4.3.1 Situational Awareness and Real-Time Vulnerability Assessments

Situational awareness will provide an accurate assessment of power system reliability, taking account of the rapid variations and intermittency of renewable energy resources, contingency events, and equipment failures. The target for an on-line situational awareness computational tool is full validation in relation to T&D system reliability metrics and contingency events that incorporate DER uncertainties and T&D operational scenarios. Situational awareness tools will also be able to provide derived capability of nodes at the intersection of T&D to provide services, with decision support able to reconcile this information about services into choices and impacts. Situational awareness will need to be provided in real time along with daily and hourly forecasts of potential reconfiguration needs for bulk power transport.

Vulnerability assessment determines the likelihood and potential impact of contingencies, cascading events, and threats [40-41]. To enhance situational awareness capability, the tool used for vulnerability assessment should apply data-driven methods to overcome any measurement errors or inaccuracies in the system model. Historical data should be used to train ML models to overcome any inefficiency in the power system model, including data on self-healing and rapidly changing power system parameters and topology.

When the system enters an extreme operating condition during a catastrophic outage, the goal of situational awareness tools is to provide a full damage assessment report; forecast the availability of generation resources, critical load, and reconfiguration options; and optimize control and recovery actions. In the integrated T&D grid of the future, available black-start and resiliency sources will need to be identified. Operation and control resources are critical to maintaining the stability of microgrids or small distribution subsystems that must be used to serve critical loads. The target is for the proposed DIS to fully provide the critical information and measurements to determine situational awareness and assess vulnerability.

A T&D grid may be vulnerable to extreme weather conditions, wildfires, or cyber attacks. Vulnerability metrics will need to be available to indicate the system's ability to withstand cascading events and determine the necessary defensive response. The power industry has established power system security metrics, such as N-k security. However, metrics for cascading events and distribution system impacts are still in the development stage. Similarly, for defensive actions, basic wide-area remedial action schemes have been deployed for decades. However, they are designed for specific scenarios, not for unanticipated events that have not been incorporated in the design. The goal for the future is a suite of ML and optimization technologies for situational awareness and vulnerability assessment that will be capable of responding to extreme events in general and not simply the small number of anticipated cases in an integrated T&D operational environment.

One of the R&D recommendations in this paper is to study the situational awareness of a distribution system as part of an integrated T&D system. The new capabilities should include assessing T&D power system security, forecasting generation and load, maximizing utilization of renewable resources, enhancing resilience, and assessing damage for purposes of system restoration. In the long run, it is conceivable that the power grid will become more "self-aware" by reducing dependence on smart meters at customer sites and enhancing the capability of distributed state estimation in the distribution system.

4.3.2 Decision Support

Decision-support hardware and software tools are meant to inform human (system dispatcher/operator) decision making, which requires higher-level functions than are needed for other analytic tools that are dedicated to well-defined computational tasks, such as power-flow and fault-current calculations, and are based on mathematical models and numerical computations. Examples of decision-support tools are logic reasoning and empirical judgment based on incomplete information and uncertainties. Personnel safety is often involved in system dispatcher/operator decisions regarding switching actions performed by the field crew. Decision-support tools provide critical data and information from various sources to support decision making.

For operators moving into future a data-driven decision support environment, the way in which information is dispatched both to and by them, i.e., through ML and other data analytics technologies, will be key, as will the process of operators growing to trust information generated in this way. Distribution system operators will need to be trained to interact with the decision support system by using a simulator to navigate pre-determined scenarios. Such integrated training schemes will allow operators to engage with ML and AI-based systems for decision support, and to develop confidence in the systems.

A data-driven decision support process might result in decisions that involve tradeoffs, for example during a major event, when an outage is likely, the potential to dispatch a large distribution resource to maintain power service for most customers while having to reduce power quality for some customers. The utility, aside from balancing operational safety, may be inclined to consider financial consequences and reliability constraints. A true ML-based operation could provide a set of tradeoffs for meeting those objectives, which could be quickly reconciled by a human operator. No single decision is potentially the correct one for all consumers, aside from a safety action preventing a loss of life. ML is poised to be the decision maker for near-term decisions. AI and ML might be limited by not being able to account for institutional knowledge or unexpected changes in the power system condition. However, operators generally know their systems well and can determine which actions proposed by ML would not work. Therefore, using a hybrid AI–human decision-making approach integrating the strengths of system operators and AI tools is beneficial.

Considerations in the development of a hybrid human–ML/AI decision support environment include:

1. To what objectives should new ML techniques be applied to best assist grid operators?
2. How will new ML techniques complement or replace traditional techniques?
3. What are the computational and data requirements for training new models, and how will the cost of adoption be met?
4. What hardware and processing needs must be met to implement the new decision-support system?
5. What are best methods for training and transition to the new decision-support system?
6. Where will the continuous ML development process be performed and by whom (internal or external staffing)?

Regarding item 3 above, to enable decision-support tools with increasing data needs, R&D is needed to identify what data are needed, at what resolution, how often acquired, and how to protect consumer privacy. Data needs may vary depending on the electrical and geographical configurations of the distribution system.

R&D needs to be conducted to enable communications among dispatchers and operators in an integrated T&D environment, including visualization that would give operators the ability to assess system operating conditions and risks and prepare for emergency scenarios. The integrated T&D environment should allow a seamless integration with power flow, on-line security, and power system restoration functions.

The proposed DIS would provide the data/measurements for decision-support tools in an on-line environment. SCADA and AMI need to be networked with the DIS, and the network optimized, for operation, control, and electricity market functions.

Test systems, models, and tools need to be developed for validating the analytics and decision-support tools in an integrated T&D environment. These test systems should include both transmission and distribution subsystems to represent the T&D interface in a realistic manner.

Operational use cases for AI-enabled decision support need to be developed and demonstrated in a decentralized environment with a high penetration of DER. These use cases should include AI-ML-based forecasting of intermittent generation, flexible load, and microgrids.

Distributed decision making is critical for the future decision support tools and environment. An integrated T&D environment is needed that incorporates decentralized operation and control in distribution systems. The interface and integration between EMSs and ADMSs are important areas. AI-based testbeds for integrating new algorithms can be powerful tools for training and tool evaluation as well as for technology transition for the future operational environment.

4.4 Operators and Control Centers

For the future vision of an integrated T&D grid, collaboration between transmission dispatchers and distribution operators must be enhanced to enable decision making that allows distribution subsystems to support the transmission system's operational tasks. Transmission energy control centers need to be closely integrated with distribution operating centers. This includes integrating data/information acquisition and space and facilities as well as fostering teamwork among operators and dispatchers. At the transmission level, it is common to have two concurrent control centers for to ensure resiliency. Integrated T&D operations and information flow will have to apply seamlessly to both control centers. For system operators to feel confident when they take actions, they need to know that data, analytics, and models serving their control centers are secure and accurate.

The need for close collaboration raises important considerations for the design of future control centers and training of dispatchers and operators. As noted above, integration of data acquisition, power system security assessment, outage management, and service restoration naturally facilitates integration of space and facilities, hardware and software functions, and teamwork for dispatchers and operators. The operator training simulators of the future will require interface or integration between transmission EMSs and distribution ADMSs. Human- machine interfaces must be developed that potentially allow for secure remote access.

As advanced decision-support tools are integrated into the T&D environment, distribution operators and transmission dispatchers of the future will require a higher level of technological training and development than is needed today. The goal is a new training environment incorporating features and scenarios of integrated and coordinated T&D operation, including black start and remedial control in the transmission system. In recent years, visualization has played a significant role in on-line computational and informational tools. A good example is the representation of power system operating conditions with visualization techniques. The R&D target is to provide a future T&D visualization and collaboration environment that takes into account human factors. Specific targets include a proposed hybrid-AI environment in which final decisions can be made by humans or machines, depending on operator comfort with using, and confidence in, the system. Design of these interfaces will also influence the nature of the future workforce.

4.5 Cyber Security and Privacy

There is an opportunity to develop and deploy a comprehensive cyber-security monitoring system in the future DIS that is envisioned in this paper. This monitoring system would provide a seamless security and defense framework across the entire attack surface.

One may argue that subsystem segmentation creates a natural barrier against cyber attacks propagating from one subsystem to another. However, vulnerabilities arise if the subsystems are not monitored and protected. For example, smart meters can connect or disconnect service to a customer at the metered location. A wide-area attack on smart meters could disconnect large numbers of customers while there would be no indication of the outage's nature or extent from the operating center's SCADA system. The only way the system would receive notice of the outage would be from customer trouble calls or when smart meter outage reports began to emerge from the AMI minutes later, depending on the communication system's design capability and performance. With an integrated DIS, a comprehensive cyber-security monitoring system would retrieve the data/information from different sources and perform logic reasoning to reconstruct the scenario's cause and effects, potentially relying on dedicated sensors. Advanced cyber state-estimation algorithms can be integrated to the operational layer with enhanced data availability.

Remote monitoring can provide status and measurements of DER. It is important to establish the DER customer - utility boundary for purposes of real-time communication of capability via a secure data-transport layer. Consumer and operations information need to be separated, and federated control boundaries established, to protect customer privacy and ownership while allowing coordination of the DER network with full capability of monitoring devices.

An interconnected power system serves multiple power utilities. The privacy policies of each utility system limit data exchange. A cloud server could play the role of a high-level control center but R&D on privacy will be increasingly important to prevent sharing of sensitive grid or market data to untrustworthy cloud environments.

Cyber security and privacy are separate but related issues that affect not only the envisioned DIS but also the entire five-layered architecture of the future system. Cyber-security solutions may include passwords, firewalls, encryption, authentication, and systemic anomaly detection and mitigation [42-43]. Some technologies, e.g., firewalls, already exist. Some, such as encryption, are not widely adopted on power grids. Solutions for anomaly detection over the entire attack surface are not currently available but will be critical for holistic monitoring and defense.

In addition to cyber security, privacy protection is a serious concern for consumers and utilities. Smart meters collect energy consumption patterns and information that could be considered an intrusion on consumers' privacy. R&D is needed to determine the minimum amount of information required for grid operations without violation of privacy. A utility company in a competitive market environment also has the concern of private data being shared with competitors. Privacy needs to be maintained as utility companies cooperate and share data in a wide-area operational environment. Research is emerging concerning how utility companies can preserve privacy as they provide data for the common good, such as for state estimation of the wide-area grid [44].

There is a critical need for a *holistic* methodology and tool for cyber, physical, and information security of the DIS and other operation and control, market, and business systems. Privacy needs to be preserved as data and information systems are integrated. Preserving privacy during close coordination between T&D, and between power grids and third parties, will be important to address.

5. Research and Development Recommendations & Implementation

Key to realizing the future vision of the grid presented in this paper will be a representation of the DSO-ISO interface in both virtual and physical environments. R&D must address the information needs of the integrated system, the impacts on operational constraints, and prioritization or negotiation of competing needs. Dispatch of a decentralized system that encompasses distributed generators, VPPs, and active consumers will need to take place at a speed faster than can be accomplished manually by human operators.

The solutions necessary to realize an integrated T&D grid are multi-disciplinary; their development will require a holistic R&D portfolio and teams that incorporate experts from a number of fields, including power engineering, optimization, cyber-physical system security, networking, and data science.

We have organized our R&D recommendations around the five layers of the operation and control architecture envisioned for the integrated T&D grid of the future. The layers are listed below along with the major themes and focal areas encompassed by the R&D activities that are recommended for each layer:

- **Enhanced Data/Information**
  R&D themes: DER/load information such as energy and control capacities, availability for scheduled trading, operational or control actions, location of connection with the distribution grid, protection design, status/analog data, and measurements from meters and sensors.
- **Data Analytics and Protection/Control Technologies**
  R&D themes: 1) Control devices and systems installed on the grid and at DER and locations with significant load 2) Computational tools to be used by DER owners and loads in an electricity market environment
- **Grid Decision-Support Environment, Tools, and Communications**
  R&D themes: 1) Decision-support and analytical tools used by distribution operators to schedule operations and support reliable, resilient, cyber-secure transmission grid operation 2) Computational tools to determine the ancillary services necessary to maintain system reliability and resilience, including ADMS, outage management, and service restoration
- **Operators and Control Centers**
  R&D themes: 1) Means for distribution grid operating centers and DER/microgrid operating centers to coordinate with energy control centers in the transmission system, including data sharing; field-crew dispatch; and planning, operational, control, and restoration tasks 2) Workforce development

- **Cyber Security and Privacy**
  R&D themes: A holistic strategy for cyber-physical system security and data privacy of stakeholders

Detailed recommendations for each layer of the operation and control architecture are described in the subsections below. For each layer, we list the elements of the future grid vision that are supported by that specific layer of the architecture. The elements of the vision are defined and identified numerically (V1, V2, etc.) in Section 3. Enabling technologies for that layer are also listed.

Under each layer, the R&D recommendations are numbered (R1, R2, etc.) and categorized in terms of priority and time frame. Priorities are high or medium. A high-priority recommendation is considered fundamental to achieving proposed vision and solutions and would have a transformative effect. A medium-priority recommendation builds upon, or is needed to validate, foundational technologies. The time frame definitions are: <5 years (near term); 5-10 years (medium term); > 10 years (long term). At the end of each individual recommendation is a summary of the impact (outcomes) expected from those specific R&D efforts.

5.1 Enhanced Data/Information

Enhanced data and information enable full observability and analytical capabilities for the integrated T&D operations environment, with an active, decentralized distribution system.
Supporting Vision V3: Information availability, and V5: Secure data networks
Enabling Technologies: Sensors, data integration, and communications systems

R1: Cohesive Sensing, Measurement, Communications, and Advanced Analytics Plan for Integrated Transmission & Distribution Operations & Sensors *(see also Section 4.1)*

Priority: High; Term: 1 to 5 years

This recommendation is to evaluate, in a holistic manner, the sensing and integrated communications needs of the T&D interface, with a focus on the time scales of data delivery, hierarchy of analytical integration (i.e. local, distributed, or central), performance need (control or observation), and latency requirements. This plan should evaluate the system as a whole, with a view to initially determining the types of measurements needed to achieve the global objectives of observability and controllability for maintaining bulk system stability based on identified metrics. Benchmark performance needs should be defined for sensing, communications, bandwidth, and analytics, to enable investment planning and sensor target-setting. Overall value should be quantified. Gaps in standards and interoperability for secure integration of sensing and analytics into an operational environment should be determined. A targeted pilot scheme should be developed for transition of sensing devices and strategies from lab to field and commercial practice. Requirements and standards should be developed for sensors' interoperability with a range of vendor management tools, and targeted performance defined based on required future functionality. A plan for integration of sensors and sensor data should include end-to-end costing and communications specifications as standard practice.

Impact: Enhanced sensing and measurement decision-support tools for integrated T&D operations using AI and ML.

R2: Design, Development, and Testing of Information and Communications Technology for Distributed Information Systems *(see also Section 4.1.2)*

Priority: High; Term: 1 to 10 years

The goal of DIS communication technology R&D is to:

- Provide full observability with time-synchronized (<1ms latency, 0.1ms synchronization error, 0.5% accuracy) voltage and current measurements during normal and faulted conditions.
- Establish remote communication, control, and fault-indicating capabilities in a networked environment.
- Develop an operational system that can securely reach into both T&D and provide both deep-dive and high-level views of system conditions for operational visibility.
- Develop a communications system that is adaptive, secure, and extensible, offering plug-and-play capability for new types of sensors and measurement devices.

Impact: Deployment of technology that provides high observability, enabling situational awareness in distribution systems to support transmission system operations and distribution system monitoring, operation, and control. Quantified affordability, reliability, security and privacy from the consumers' point of view.

R3: Test Systems, Models and Tools for Validation of T&D Methods *(see also Section 4.3.2)*

Priority: Medium; Term: 1 to 5 years

- Develop and evaluate test systems involving both T&D subsystems.
- Develop models for analytical methods and computational algorithms, synthesize data that represent realistic conditions.
- Develop requirements for data collection for pilots of test systems that include DER and microgrids, as well as cyber systems for information and communications.
- Develop and standardize benchmarking techniques for R&D data sets, vetted by industry, to enable comparative evaluation of algorithm and sensor developments. Data sets will become a requirement for research products, along with data samples to be used with new sensing mechanisms.

Impact: Enhanced capability to evaluate the performance of proposed T&D methods and tools; Comprehensive requirements for testing and validation of T&D methods and tools; Improved testing and validation incorporating both cyber and physical systems for power grids, DER, and microgrids.

5.2 Data Analytics and Protection/Controls Technologies

An advanced analytical environment is needed to support visualization and operation of the integrated system.

Supporting Vision V1: High penetration of DER, V2: Non-wire alternatives, and V6: Changing workforce
Enabling technologies: Computational tools, including optimization and AI/ML based tools, in an integrated T&D environment, tools to enable situational awareness and resilience in an environment with high penetration of DER

R4: Development and Demonstration of Operations Use Cases for Artificial-Intelligence-Enabled Decision Support in a Decentralized Environment with High Penetration of Distributed Energy Resources *(see also Section 4.3.2)*

Priority: High; Term: 5 to 10 years

- Support decision making in a transmission environment by incorporating decentralized operation and control in distribution systems.
- Develop AI-ML-based forecasting of intermittent generation and flexible load.
- Develop roadmap and demonstration program for transitional ML.
- Develop AI techniques used in decision support, industrial interoperability, and AI standards for grid operations.
- Develop predictive and proactive operational schemes for replacement and retirement of assets, with whole-system view.

Impact: New AI decision-support tools for use in a decentralized environment with high penetration of DER and microgrids.

R5: Situational Awareness of Distribution Systems *(see also Section 4.3.1)*

Priority: High; Term: 10 to 15 years

- Develop T&D system security and fast-ramping generation and load for contingencies.
- Develop reliable methods to forecast generation and load and determine availability of generation.
- Develop means for maximal utilization of renewable energy to approximately 30 to 50% penetration in 20 years.
- Develop on-line resilience assessment to use as a metric in decision support.
- Develop holistic visualization capabilities for T&D communications, combining data-driven and modeling techniques for consistency across networks, to support damage assessment and power system restoration on the transmission side in an outage.

Impact: Availability of new decision-support tool that will improve power system security and resilience assessment and control on the transmission side. Flexible operation and control of T&D system, which will minimize curtailment of renewable energy. Enhancement of damage assessment for system resilience following extreme events.

***R6: Transmission, Distribution, and Communications Tools for an Integrated Transmission and Distribution System** (see also Section 4.3.2)*

The goal of this R&D effort is to develop tools for communications operations in the integrated T & D environment, including communications visualization to enable operators to evaluate changing topologies and emergency scenarios.

Priority: High; Term: 5 to 10 years

Computational tools to be developed and incorporated into the integrated T&D operational environment include:

- Accurate, data-driven T&D power-flow and state-estimation modeling and computation, with predictive capabilities
- T&D black-start and power system restoration tools with hybrid AI decision support
- T&D on-line security evaluation software algorithms for resilience and reliability
- T&D on-line evaluation of power-system dynamics for variations in generation and load as well as uncertainties, enhanced with dynamic sensing capabilities

Impact: New capabilities for cooperative T&D and communications for on-line steady-state and dynamic security evaluation, black-start, and power system restoration. Improved accuracy and consistency of power system models and computational algorithms. Improved reliability and resilience of T&D. Integration of communications operations visualization and outage management.

5.3 Grid Decision-Support Environment, Tools, and Communications

The goal of decision-support R&D is to develop a hybrid human-AI decision-support environment with full visualization (including nodal deep-dive visualization), predictive impact assessment, and integration of decision making with operational tools.

Supporting Vision V4: Hybrid human-AI environment

Enabling Technologies: Roadmap and demonstration program for transitional ML, operational AI and ML program, AI and ML tools for distributed decision support, development and demonstration of operations use cases for AI-enabled decision support in a decentralized environment with high penetration of DER.

***R7: Artificial Intelligence and Machine Learning Tools for Distributed Decision Support** (see also Section 4.3.2)*

Priority: High; Term: 10 to 15 years

AI and ML tools and operational schemes needed for distribution system decision support include:

- Predictive and proactive operational schemes for replacement and retirement of assets and a whole-system view (see also Section 4.5)
- Integrated tools supporting decision making in a transmission environment that incorporates decentralized distribution system operation and control; AI-ML-based forecasting of intermittent generation and flexible load; network-wide data integration

Activities related to developing AI/ML tools for decision support include:

- Piloting and implementing hybrid-AI test beds to transition new algorithms to operational environments, for training and performance assessment
- Integrating computer visualization tools for remote sensing and multi-modal sources

Impact: New distributed AI-ML tools that improve visualization for decision support and self-healing in T&D environments. Distributed intelligence from the distribution level integrated with operation and control at the transmission level.

5.4 Operators and Control Centers

R&D for the Operators and Control Centers layer focuses on engaging a future workforce that can function in a hybrid, integrated operational environment.

Supporting Vision V6: Changing workforce, and V4: Hybrid human-AI environment

Enabling technologies: Human-machine interface and visualization techniques to support operators and control center functions, computer simulation technologies for workforce training and development programs

R8: Communications, Visualization Tools, and their Incorporation into an Integrated Transmission and Distribution Environment *(see also Section 4.3.2)*

Priority: Medium; Term: 1 to 10 years

This recommendation focuses on developing a new networking environment that enables integration of T&D communication systems. Specific activities include:

- Develop a new networked environment that enables integration of T&D communication systems, including SCADA and DISs.
- Develop a software and visualization environment for integrated T&D systems, including integration and interface between EMSs and ADMSs.
- Pilot a scheme for enhanced, flexible, secure, reliable communications networks in a range of utility and operational environments, integrated with sensing and interoperability requirements.

Impact: Enhanced observability of the T&D communications system. Improved monitoring and control of the integrated T&D system.

R9: Workforce Development *(see also Section 3.3.3)*

Priority: High; Term: 1 to 20 years

The goal of the following recommended activities is to support the development of a diverse future workforce that has a range of traditional and modern skills:

- Provide training and apprentice programs for participants to learn to use new technologies, including creating operator training environments.
- Develop K-12, community college, and university programs, designed by experts in power systems, data science, cybersecurity and networking.

- Create a roadmap for apprenticeship and fellowship in computational fields, enabling subject-matter knowledge transfer to data science and computational communities.
- Diversify utility and industry R&D workforce through leadership, education, and apprenticeship programs.

Impact: Creation of education programs to develop and support a workforce that has the skills to operate in the integrated environment of the future grid. Improvement of diversity of the workforce in the power systems industry from the ground up.

5.5 Cyber Security and Privacy

The goal of the following recommendations is to enable a secure data and energy delivery system.

Supporting Vision V7: Secure integrated environment

Enabling technologies: Tools for protection and mitigation of cyber attacks, software technologies to enable integration of the cyber system and physical system models, privacy protection of data and information

R10: Cyber-Physical System Security Tools for Transmission and Distribution Systems *(see also Section 4.5)*

Priority: High; Term: 1 to 10 years

This recommendation encompasses the following activities:

- Develop and validate a holistic methodology and tools for cyber, physical, and information security of the integrated T&D system, the DIS system, and associated communications.
- Develop operational integration of anomaly detection and Behind-The-Meter data while preserving privacy.
- Bridge cyber-security gaps among subsystems of transmission SCADA, distribution SCADA, PMUs, substations, and distribution automation/AMI.
- Coordinate cyber security among T&D utilities and third-party owners.

Impact: New comprehensive cyber-physical system security tools for T&D systems that prevent cyber intrusions into vulnerable subsystems that would enable attack on other critical subsystems. Enhanced system security monitoring and defense by anomaly detection and mitigation across T&D facilities. Improved capability to detect and stop intrusions within the cyber system before they affect the physical system, enhanced protection of privacy for data and information.

6. Justification for Federal Support

This paper presents a vision of the future grid in which distributed resources and the distribution system have evolved into a cohesive part of the transmission system operations environment. Realization of this vision depends on a wide range of research, development, pilot, and integration activities taking place during the coming years. Although the process will be driven in part by various stakeholders, including consumers, utilities, and industry, federally funded research should be directed to overcome numerous barriers to the achievement of this vision. Federal funding could and should support development of interoperability; definition of the architecture of the integrated T&D system; definition of boundaries, regulations, and standards for the integrated system; adoption of AI within the integrated system; and development of tools for and sensing and measurement to enable secure, reliable operation of the integrated system.

Barriers to implementation of the vision include

- Cost of sensing and measurement and deployment of the sensor/measurement infrastructure
- Lack of standards, real-world pilots, and transitional tools for integrating AI and enhanced data streams
- Need for workforce development and workforce education pathways
- Need for boundaries and regulations for T&D Integration
- Challenges related to vendors, interoperability, and the supply chain
- Need for modeling and simulation tools and research data sets that accurately represent operational conditions

The barriers listed above can be overcome with strategically focused R&D investments and integrated public-private partnerships that address lack of opportunity to pilot and scale up tools such as sensors, measurement devices, and AI.

Section 5 of this paper reviews in detail the research needed to enable the long-term future vision we propose of integrated T&D system operation. For each of the goals outlined in Section 5, there are a number of foundational, short-term efforts that are essential to realization of the future vision and are also low-hanging fruit in terms of integration and operations developments. These short-term goals are urgent foundational requirements that must be met in the next 1 to 3 years for the future vision of the grid to be realized. These foundational goals are summarized below in relation to existing DOE programs and areas where DOE focus and funding could be directed to support efficient achievement of the long-term vision.

Foundational goals include:

a) Development of an integrated T&D data, sensing, and communications plan, with benchmarking and operational use cases

b) Design and testing of a new DIS that is secure, reliable, and integrates data elements

c) Development of a hybrid AI and ML roadmap and use cases as well as a benefits assessment for a test system environment and for new operational elements, considering the current state of the art in parallel fields and critical environments

d) Development of a comprehensive, high-volume, modernized set of validated, representative operational test models and data sets for the future integrated T&D system and its associated communications

e) Pre-emptive development of diverse K-12, higher-education, and industry apprenticeship pipelines for the future engineering, security, and science workforce for the energy delivery industry

f) Development of a targeted, expanded pilot and demonstration transition scheme for rapid bridging of the research - commercialization gap

The above near-term goals must be urgently met to ensure the future of an integrated T&D operations environment that will enable a clean, reliable, resilient future energy delivery system.

The elements of the vision in which the distribution system operates as a function of the transmission system span numerous DOE programs beyond the transmission R & D program. DOE could play a valuable role by uniting what is now separate research in transmission and distribution and shifting to R&D that considers a single, integrated, cohesive T&D system. DOE programs relevant to this overall goal and the specific immediate goals listed above include:

DOE Office of Electricity Advanced Grid Research: Sensing and Measurement

DOE Office of Electricity Advanced Grid Research: North American Energy Resilience Model

DOE Electricity Artificial Intelligence and Technology Office

DOE Office of Energy Efficiency and Renewable Energy: Solar Technologies & Vehicles and Buildings Technology Offices

AI is a key example of one of the areas ripe for scientific development through the Artificial Intelligence and Technology Office, possibly allowing for piloting and scale up of related technologies.

A unique, beneficial crosscutting role that DOE could play would be to fund development of a combined roadmap of technologies across the spectrum of domains that will be involved in realizing the future T&D grid vision. These domains include power systems, computer science, cyber security, and networking.

Other key areas ideally suited for DOE engagement above and beyond directed R&D include:

- Developing a data/information infrastructure to enable monitoring and analytics for integrated T&D operation and control
- Developing standards and interoperability for sensing and measurement, including evaluating the need for a whole-system approach, rather than vendor- and data-driven systems, and developing a cohesive plan to get to 100% distribution system visibility
- Establishing consistent and appropriate-size/volume data sets for AI integration and operational processes testing, including coordination among academia, national labs, and industry to reach that goal
- Evaluating whole-system and system-of-systems security
- Developing interoperability of devices for coordinated, collaborative operation of distribution
- Quantifying the value of the future states of the grid and investments needed to achieve projected technology costs over time

A number of specific foundational activities are needed specifically in the area of architecture for DSO and ISO integration including:

- The addition of product, tool, or algorithm scalability metrics and documentation of success stories from demonstration projects
- Development of technology demonstration programs in which transmission and distribution entities work together, devising programs to provide T&D integration opportunities for utilities, and offering pilot program guidelines and technology-pitching assistance for pilots and joint working groups, including:
    - Solidifying public-private partnerships across projects and programs, minimizing dependencies on researcher relationships to drive activities
    - Supporting peer review for funded initiatives, demonstrations, and pilots, grouped by type of technology within an office, rather than by individual programs, to enable visibility across the range of activities
    - Planning for separate tool or product development cycles and demonstration cycles
- Supporting workforce development partnerships with high school education and science, technology, engineering and mathematics curricula; planning for 20-year workforce needs; and improving diversity in educational streams and industry

Because DOE R&D is funded by taxpayers, it is critical to demonstrate the value of the research to the taxpaying public. Important considerations in consumers' minds include affordability and reliability. As the proposed DOE R&D agenda develops, it will be important to document the benefits and quantitative metrics for increased reliability, resilience, and security of the energy delivery system. Clear roadmaps and documentation of the value to consumers will be critical to gaining support for the vision from of regulators at different levels.

Beyond technological issues, this paper also identifies non-technical (societal, economic, and regulatory) barriers to the grid vision. Further research is needed into these relevant non-technical challenges. For example, if retail markets are needed to incentivize large-scale deployment and energy and service trading for DER, research will be needed to articulate the barriers to developing these markets and the ways to remove or reduce the barriers.

7. Summary and Conclusions

For the past two decades, U.S. electricity transmission and distribution systems have been undergoing an accelerating transformation. The level of penetration of renewable energy and DER, including demand response, has increased significantly leading to fundamental shifts in the generation mix and in the nature of, and need for, monitoring and control in the transmission and distribution grids. These shifts have important implications for future operation, control, and trading of electrical energy. One of the most critical changes is that the transmission and distribution systems will no longer be able to be operated independently because DER are connected primarily at the distribution level but are important resources for operation and control of the transmission system.

This white paper focuses on the integration of transmission and distribution system operations and controls. In Section 2 of the paper, we identify seven drivers of the shift to an integrated T&D system. These drivers are:

D1*:* An expected exponential increase in first-generation DER, penetration of DER on the distribution grid, and retirement of traditional assets

D2: Need and desire for non-wire-yet-operational alternatives, with market participation features

D3: Availability and need for information for both operators and customers

D4: Maturity of analytics technologies in relevant fields

D5: Need for advanced communications and information availability

D6: Increase in stakeholder engagement, need for a workforce able to interact with the evolving T&D environment

D7: Security and resilience in an evolving threat and risk environment

These drivers cover a wide range of new developments in the power industry, such as increased penetration of DER and evolving electricity markets. However, the change in the grid is also driven by changes in information technology -- the revolution in not just in the technology itself but also in availability of data, analytics, optimization, and AI/ML. New technologies for sensing, measurement, protection, control, and microgrids offer an opportunity to enhance power grid reliability and resilience. With high-level connectivity and remote monitoring and control come vulnerabilities to cyber and physical security and threats.

At this critical juncture in the evolution of the nation's electrical energy infrastructure, it is important to develop a long-term vision and a roadmap for realizing that vision. In our proposed vision, distribution systems will operate as subsystems of the transmission grid (rather than simply as load on the transmission grid). DER (including renewables, flexible load, and microgrids) on the distribution system will support operation, control, and black start of the transmission grid, which will be accomplished in close coordination with distribution operators. DSOs will maintain grid reliability and resilience as large-scale trading of electric energy and ancillary services takes place in the distribution system environment. Data, information, optimization, and AI-based analytics will support DSOs in decision making. The integrated T&D grid that we envision will be embedded with the necessary cyber-security and privacy procedures and technologies. The proposed vision represents a fundamental transformation from current distribution system operation, which is focused on routine maintenance, outage management, and service restoration. The future integrated T&D grid will include on-line power system security assessment and situational awareness capabilities to support transmission system operation and control. The DSO will also be enabled to function as reliability coordinator of the distribution system. In a transactive energy environment, the proposed vision consists of the following 7 components, identified as V1-V7 and described in Section 3 of this paper:

V1: High penetration of operational DER, supporting both transmission- and distribution-level operations, both collaborative and cooperative; retirement of major assets

V2: Commonplace non-wire alternatives, with new markets in place to enable them

V3: Information available on demand and optimized decision-making support for consumers and operators

V4: Hybrid human - AI environment with extensive distribution support

V5: Secure public/private data networks

V6: A new workforce that is trained to interact with the new hybrid AI environment

V7: A secure integrated operational environment capable of automated response to evolving threats

The implementation of elements V1-V7 of the proposed vision will require an operations and control architecture that has five layers, as explained in Section 4:

1. *Enhanced Data/Information* (supporting Vision V3: Information availability, and V5: Communications)
2. *Data Analytics and Protection/Control Technologies* (supporting Vision V1: High penetration of DER, Vision V2: Non-wire alternatives)
3. *Grid Decision Support Environment, Tools, and Communications* (supporting Vision V4: Hybrid human-AI environment)
4. *Operators and Control Centers* (supporting Vision V6: Changing workforce)
5. *Cyber Security and Privacy* (supporting Vision V7: Secure integrated environment)

The proposed architecture is an integrated structure of technological and non-technological solutions. Interfaces must be developed for communication and coordination among the different layers. The fundamental technology solution is a DIS with IIDs deployed on the distribution system in a networked environment that provides high observability and enables situational awareness and decision support for an integrated distribution and transmission system.

Our recommendations for R&D funding by DOE focus on the need for data/information, analytics, and decision support to enable the distribution system to function as a subsystem supporting transmission system operation. As described in Section 5, we offer 10 recommendations, R1-R10, according to the five layers of the proposed architecture:

Enhanced Data/Information (supporting Vision V3: Information Availability, and V5: Communications)

R1: *Cohesive Sensing, Measurement, Communications, and Advanced Analytics Plan for Integrated T & D Operations & Sensors*
R2: Design, Development, and Testing of Information and Communications Technology for Distributed Information System
R3: Test Systems, Models, and Tools for Validation of T&D Methods

Data Analytics and Protection/Control Technologies (supporting Vision V1: High Penetration of DER, V2: Non-wire Alternatives, and V6: Changing Workforce)

R4: Development and Demonstration of Operations Use Cases for AI-Enabled Decision Support in a Decentralized Environment with High Penetration of DER
R5: Situational Awareness of Distribution System
R6: Transmission, Distribution, and Communications Tools for an Integrated T&D System

Grid Decision-Support Environment, Tools, and Communications (supporting Vision V4: Hybrid human-AI environment)

R7: AI and ML Tools for Distributed Decision Support

Operators and Control Centers (Supporting Vision V6: Changing workforce, and V4: Hybrid human-AI environment)

R8: Communications, Visualization Tools, and their Incorporation into an Integrated T&D Environment
R9: Workforce Development

Cyber Security and Privacy (supporting Vision V7: Secure integrated environment)

R10: Cyber-Physical System Security Tools for T&D Systems

Uncertainties associated with essential technologies will impact the pace and effectiveness of the realization of the proposed vision of integrating transmission and distribution into a single operational environment. For example, penetration of EVs and energy storage in the distribution system environment will depend on technology improvements and cost reductions during the next several years. The availability of energy storage (in the form of EVs or other devices) is critical for ancillary services that distribution systems will need in order to maintain reliability and resilience. Similarly, as the cost and performance of microgrids continue to improve, DSOs will be able to gain access to the capabilities of microgrid controllers, enhancing the DSOs' capability to support transmission operation.

Technology alone will not be sufficient to achieve the ultimate goal of an integrated T&D operational environment. Challenges in related areas must also be addressed. Regulatory barriers need to be removed to allow for retail transactive energy and ancillary service markets at the distribution level. The interaction between the wholesale market at the transmission level and retail markets at the distribution level has not been studied, for example, the opportunities for arbitrage between the transmission and distribution markets and the possibility of market power in the distribution system environment. Exercise of market power is likely in a distribution system that has limited redundancy in delivery paths and therefore has bottlenecks that can cause congestion, which would drive up prices. Customer behavior will also affect future development of power grids as will growing concern over climate change, which will likely accelerate electrification (and adoption of EVs) and retirement of facilities that rely on fossil fuels. Workforce transition is a key challenge where engagement of the federal government in education of young students and in piloting partnerships with utilities and laboratories to support knowledge transfer and fellowships would significantly improve training pathways for future generations of power system operators and engineers. There is also a need for pilot programs, and lessons learned from pilots, to consistently grow the technologies needed to support the future grid.

It is recommended that DOE concentrate on development of the infrastructure and enabling technologies that will serve as foundations for a transformation of the T&D systems during the next decade. An efficient path to adoption of advanced technologies is needed for the power industry to implement the fundamental changes that are necessary to realize the vision of a future grid. As discussed in this paper, distribution systems today are far from ready to participate in transmission operation as subsystems. Perhaps the most basic weak link in distribution system infrastructure is low observability and controllability. The proposed DIS is an enabling technology for integrated T&D operation that addresses the current lack of observability and controllability. The DIS would also be a foundation on which new analytics and AI/ML tools can be built. Development of the DIS is comparable to DOE’s long-term effort to support a synchrophasor infrastructure on the transmission grid. This future infrastructure will enable integrated transmission and distribution grids to handle complex dynamic events and set an example for power grids around the world to follow.

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