Quadrennial Technology Review 2015

Chapter 3: Enabling Modernization of the Electric Power System

Technology Assessments

Cyber and Physical Security

Designs, Architectures, and Concepts

Electric Energy Storage

Flexible and Distributed Energy Resources

Measurements, Communications, and Controls

Transmission and Distribution Components

U.S. DEPARTMENT OF ENERGY

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Measurements, Communications, and Controls

Chapter 3: Technology Assessments

Introduction

Grid operators are tasked with maintaining the generation-load balance and ensuring the safe, reliable, and cost-effective delivery of electric power. This role is of critical importance today and will continue to be so in the future. However, this task is becoming increasingly challenging owing to growing variability and uncertainties on both the generation- and load-side of the grid. On the generation side, coal plant retirements, coordination with natural gas supply, and the variability of wind and solar generation all complicate the problem of unit commitment, economic dispatch, and maintaining system stability. On the load side, demand response, customer participation, distributed generation, energy storage, and electric vehicle charging and discharging create uncertainty and shift the overall system load from one that was historically predictable. Operating the electrical power system reliably with sufficient resilience is a complex challenge because it is the ultimate "just-in-time" manufacturing and delivery process. Technologies for measurements, communications, and controls support the real-time coordination of thousands of generators, assessment of power flows across hundreds of thousands of miles of interconnected transmission lines, and delivery of electricity at the speed of light to millions of customers by means of an extensive distribution network. Until this traditional operating paradigm changes, total electricity generation must be balanced, at every instant, against total electricity demand, with various market structures and regulations guiding system configuration and behavior.

The existing suite of sensors, software tools, and control systems has been sufficient to meet reliability and resilience objectives for the past 50 years. However, the electricity delivery system has faced many significant events over the past decade—from major storms to physical attacks—that have stressed and strained the ability to provide uninterrupted electricity to customers. These events have reinforced the notion that the traditional monitoring and control approaches are no longer sufficient to meet the evolving needs of the power system and are helping to define new requirements for the future system, as shown in Table 3.E.1.

The grid's measurement, communication, and control (MCC) technologies[1] support system operators in maintaining a real-time balance between electrical generation and load, while abiding by physical limitations. Grid operators schedule power dispatch anticipating demand levels, network constraints, generator outages, and system losses. Operators designate reserves, through contracts or market mechanisms, to deal with unexpected contingencies and continuously monitor grid conditions by using sensors, communications, and computing technology. As the grid continues to modernize and become a platform for integrating clean energy technologies and enabling innovation, there will be a need for research and development (R&D) in underlying MCC technologies to advance significantly.

In the early 20th century, customers were served by dedicated local generators that simply adjusted their output to meet demand fluctuations. Over time, generators connected together and networks of transmission

Table 3.E.1 Key Monitoring and Control Attributes for the Evolving Power System

Traditional		Modern	
Observability	Controllability	Observability	Controllability
Static, slow, and local view: Weather, flows on key lines, voltages on key buses, tie flows, line status, generator status, real-power output, predictable seasonal flow patterns	**Reactive (deterministic) high-level control:** Balancing and load-following; discretized demand response; transmission limit determination based on simulation studies **[Eliminate and/or Avoid Risk]**	**Dynamic, fast, and global perspective:** Resource forecasts, interdependencies, grid stress, grid robustness, dangerous oscillations, frequency instability, voltage instability, reliability margin, and field asset information	**Predictive (probabilistic) system-wide coordination:** Generator coordination (dispatch and control); topology and flow control; demand-side coordination **[Manage Risk]**

developed, offering backup in times of equipment failure, unexpected demand, or routine maintenance as well as opportunities for improved economics (e.g., reserve sharing and access to diverse energy resources). System operators were needed to monitor load and voltage profiles, operate transmission facilities, and coordinate generation to help maintain voltage and frequency of the system. By the 1960s, the complexity of the emerging power system began to require sophisticated software-based control systems in order to reliably deliver electricity to consumers. Rapidly evolving system-level challenges—including integration of large amounts of variable generation at both transmission and distribution levels, increased susceptibility of the system to destabilizing events, and developing security issues—are underscoring the need for a new class of control systems. In recent years, parallel computing techniques, inexpensive high-speed communications, and advanced modeling frameworks have become readily available to support the modern grid.

The distribution system is often referred to as the "last mile" of the electric power system and can be considered a vulnerable link. Industry estimates show that approximately 90% of outage minutes originate on the distribution system. Owing to its size (approximately 146 million customers and 6 million miles of distribution lines nationally), it is often the most expensive part of the electric delivery system and the most difficult to upgrade. The costs of upgrades are often shared by local customers and which tends to be a few per mile outside of dense urban centers.

Traditionally, the distribution system has limited observability and controllability owing to its singular purpose of connecting customers to the transmission system. To ensure line voltages remain within limits throughout the day, voltage regulation equipment with simple control set points and fixed schedules is used. This control paradigm is based on local sensors, electromechanical devices, and "static" intelligence achieved through engineering analysis of predictable loads. Additionally, system protection is achieved through the use of fuses, breakers, and relays, and outages are located typically based on customer calls.

As energy technologies ranging from distributed generation to home energy management systems advance and become more affordable, customers will have the ability to control their energy use and produce their own electricity. These technologies may also help utilities locate customer outages before customers report them if communications channels are in place. Enabling customers to become active participants in electric power system operations and energy exchanges will require a fundamental shift in how the distribution system is designed, controlled, and protected. Maintaining reliability, power quality, and safety in this new operating environment will require new and improved capabilities.

Today's system operators are facing several challenges to achieving the grid transformation needed, including the following:

- Centralized control paradigms that primarily rely on large-scale, dispatchable generation resources
- Limited communication and sharing of operational data and system models
- System models with missing information and inconsistent and incomplete data sets that may be incompatible across systems
- Reliance on a differing array of communications methods and protocols
- Poor consistency between market, planning, and operations models
- Dependence on deterministic forecasts and tools for unit commitment, fuel scheduling, interchange scheduling, and day-ahead markets
- Limitations in computational methods and optimization algorithms for operations planning in a more dynamic and uncertain environment
- Reliance on off-line analyses, often lengthy and based on static data, to set operating limits
- Lack of real-time information for continuous asset monitoring and situational awareness
- Lack of wide-area and more sophisticated protection schemes
- Limited distribution system visibility to dynamic grid conditions

Under the American Recovery and Reinvestment (ARRA) Act of 2009, through the Smart Grid Investment Grant (SGIG) program, the U.S. Department of Energy (DOE) supported the deployment of more than 900 phasor measurement units (PMUs) across the nation—a five-fold increase of the previously installed base. Today, there are more than 1,700 PMUs deployed across the United States and Canada, primarily for transmission applications.[2] This initiative has enhanced the understanding of grid operations by providing wide-area visibility across interconnections. The primary challenge now is the development of advanced software tools and platforms that can fully exploit the information available from PMUs. Today's PMU-based applications have focused on wide-area monitoring and forensic analysis of grid disturbances. Future applications will likely include real-time and predictive control of wide-area networks, automatic balancing of supply-side variability with demand-side flexibility, and optimization of grid assets and components.

The SGIG also supported the deployment of more than 15 million smart meters throughout distribution networks across the United States. This recent widespread deployment has greatly increased the potential for monitoring voltage and current at individual consumer load points, providing more visibility into the distribution system. Currently, these sensors report energy usage and status information of customers to utilities to support several functions. These include accelerated detection and restoration of outages, faster response time to customer inquiries, and improved monitoring of customer voltage levels and reactive power needs. Near-term work includes integrating data collected from smart meters into distribution management systems (DMSs) and outage management systems (OMSs). In addition, new applications need to be developed for consumers to use and make decisions based on information they receive from their smart meters. However, data from these sensors are typically transmitted once every 5 to 15 minutes and are not time synchronized.[3]

Measurement and Monitoring

System reliability is achieved through local control and monitoring of system conditions that are then communicated to a central control center, where a combination of automated actions and human decision making seeks to ensure the system is stable and balanced at reasonable cost. Control of the grid relies especially on the measurement and monitoring of the basic electrical parameters in the transmission and distribution network—frequency, voltage, current magnitude, and phase angle—as follows:

- Frequency is a global parameter that is uniform throughout an interconnected alternating current (AC) grid. It is used as an indication of the balance between power generation and load in a power system, rising with excess generation and falling with excess load.

- Voltage is a local parameter that must be measured locally and is regulated either by means of locally generated reactive power (e.g., from shunt capacitors, electronic inverters, or rotating machines) or by the operation of nearby tap-changing transformers. At present, voltage is controlled autonomously or on fixed schedules without operator intervention.
- Current measurements in the grid provide the primary information needed for protecting costly grid elements from damage due to electrical overload, both in the steady state (e.g., exceeding the circuit rating for some period) and under fault conditions (e.g., sudden rapidly increasing current due to short circuit).
- Phase angle is based on instantaneous voltage and current measurements and provides the proportionate relationship between real and reactive power. This calculation gives operators the information needed to manage the energy flow through the network, optimize power factors, maintain target voltage levels, and protect assets.

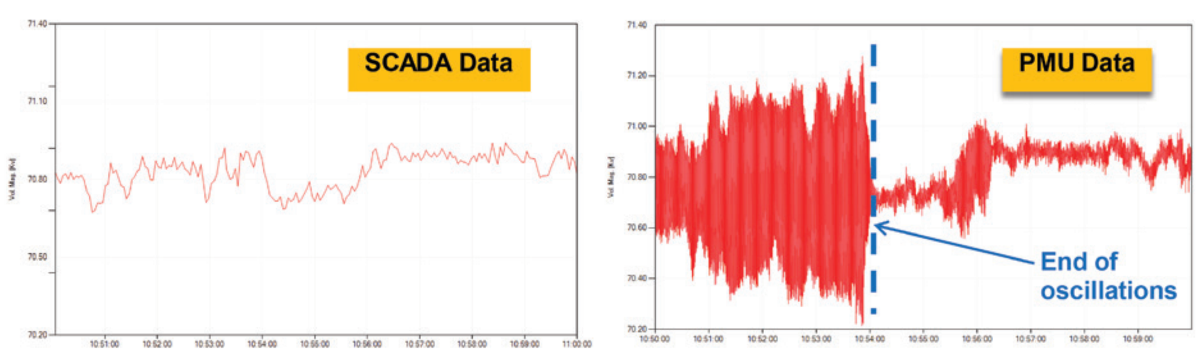
A majority of sensors deployed in the electric power system today are located within or adjacent to transmission components (e.g., power transformers and circuit breakers), typically at substations. There are also some sensors within distribution systems that are deployed at substations and along distribution lines. These sensors help measure a range of parameters such as voltage, current, harmonic distortion, real and reactive power, power factor, and fault current.

For decades, voltage and current magnitudes were measured in the bulk power system and reported to a system operator every few seconds by the Supervisory Control and Data Acquisition (SCADA) system. Current transformers (current sensors) and voltage/potential transformers (voltage sensors) are the primary technologies that have been used to date. These sensors are capable of extremely fast response (less than a millisecond) and are used to initiate local protective action (e.g., opening circuit breakers). However, SCADA systems that monitor power flow through lines, transformers, and other components typically make measurements every two to six seconds. While this sampling rate has proven adequate for steady-state operations, it is insufficient to detect the details of transient phenomena that occur on timescales of milliseconds (one 60 Hz cycle is 16 milliseconds).

The recent deployment of PMUs on the transmission system has enabled these measurements to be collected at a rate of 30 to 120 data points a second, significantly faster and at a higher resolution than existing technologies, as illustrated in Figure 3.E.1. Additionally, these PMU measurements can be time stamped (e.g., within several microseconds' accuracy using GPS time signals) and transmitted to a central location for analysis. This enhanced capability allows the phase angle[4] difference between multiple locations to be determined and is

Figure 3.E.1 Comparison of SCADA Data and PMU Data for the Same Event

Credit: Iknoor Singh, "Synchrophasor Technology Use Cases – Wind Farm Oscillation Detection and Mitigation," Electric Power Group, LLC (2014): Figure 3, screenshot from Phasor Grid Dynamics Analyzer.

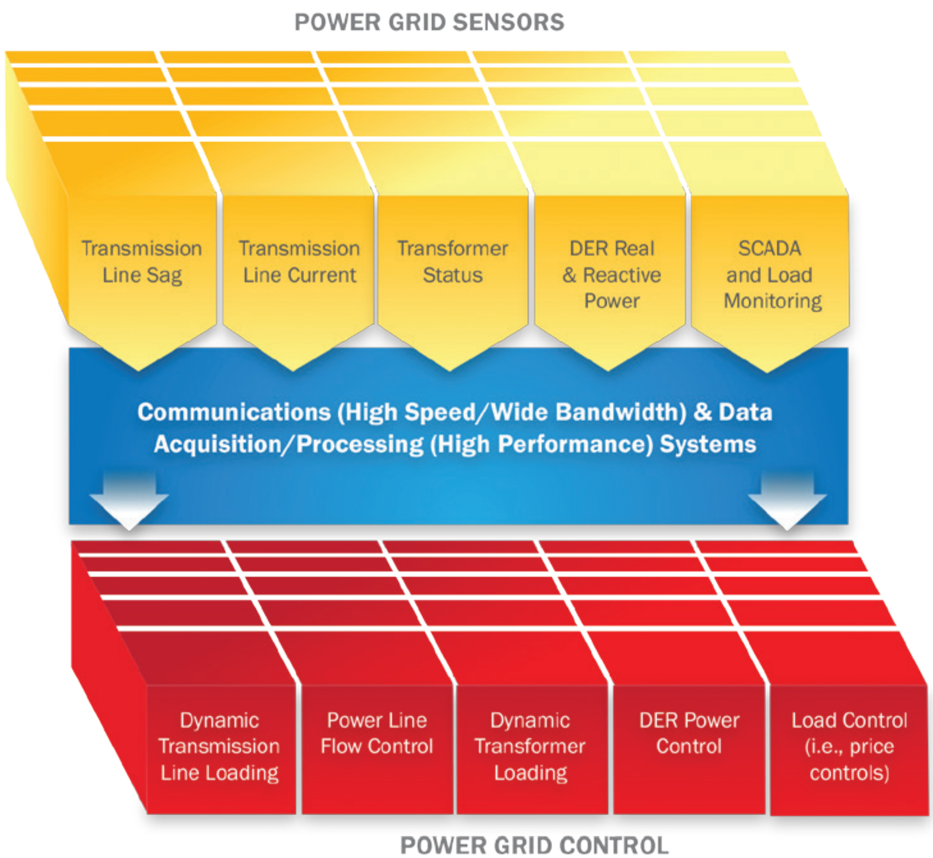


extremely useful for understanding the state of the power system. New applications ranging from diagnostics to state estimation to enhanced controls can be enabled through greater use of PMUs.

Comprehensive sensor networks will be essential to grid control applications in the future, as illustrated in Figure 3.E.2. Future grid applications will rely on accurately and timely measurement and monitoring of a range of parameters, such as frequency, voltages, currents, phase angles, power flow characteristics (both real and reactive), equipment status, loads, and weather. Industry estimates the market for all types of sensors used in smart grid applications to be nearly \$36.5 billion by 2019 and \$46.8 billion by 2021.[5]

Figure 3.E.2 Sensors-enabled Future Grid Control[6]

Credit: Oak Ridge National Laboratory

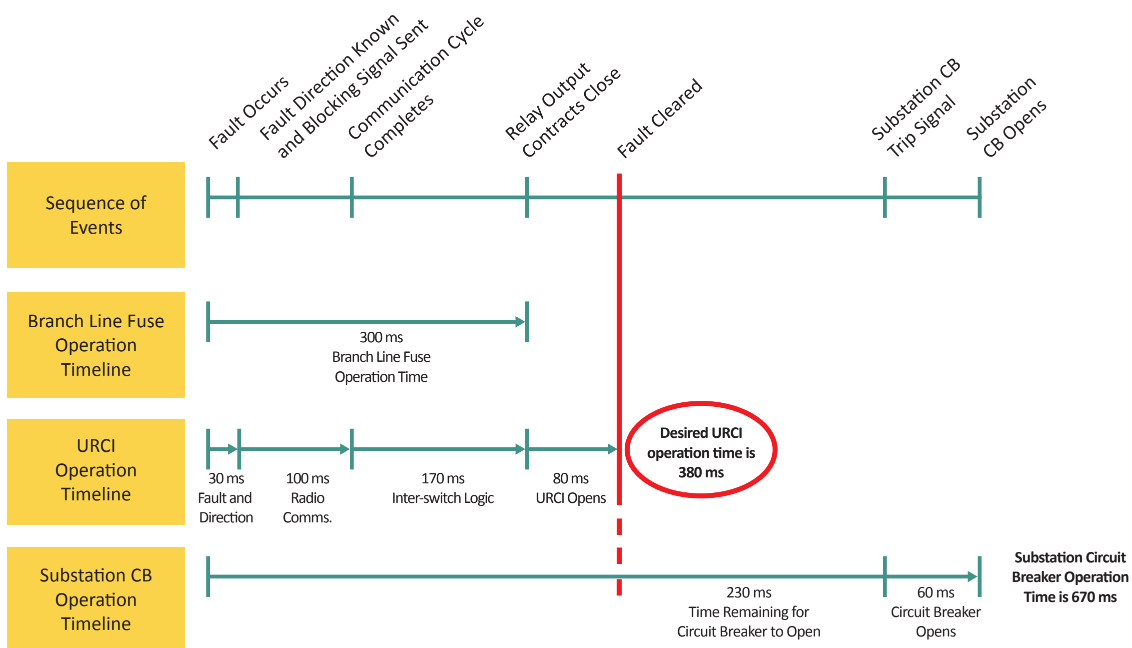


Distribution Sensors

Currently, distribution system operators (DSOs) have very limited visibility into the conditions and state of the distribution system except for into assets at a distribution substation. As more distributed energy resources (DERs) are deployed, visibility deep into the system (e.g., along a feeder to a utility meter and possibly beyond) will be needed to ensure reliability and power quality and to enable advanced applications. The installation of approximately 50 million smart meters, covering 43% of U.S. homes, has significantly helped to improve distribution visibility. These sensors provide utilities with the ability to measure consumption at significantly higher temporal resolution (e.g., every 15 minutes versus monthly meter reading). However, phenomena associated with system dynamics and protection will require much faster and higher resolution sensors that can inform operations on the order of milliseconds, as shown in Figure 3.E.3.

Figure 3.E.3 Times Associated with Clearing a Fault for Various Protection Devices (URCI = Universal Remote Circuit Interrupter)[8]

Credit: Southern California Edison Company



Various efforts to develop and use low-cost distribution sensors are being led by the University of Tennessee. Researchers are investigating the benefits of measuring frequency and voltage angle in both steady state and dynamic conditions, using frequency disturbance recorders connected at multiple consumer power outlets over a wide geographical area. Some active research areas for distribution sensors include applications of sensor information, new sensor development, sensor data collection, grid security, power harvesting, algorithms, and data visualization.[7]

Development of high-resolution distribution sensors (e.g., milliseconds) will need to be low cost for broad deployment. Micro-PMUs, or distribution phasor measurement units, can provide the enhanced visibility needed for the future grid. Micro-PMUs can help system operators and planners better understand and characterize the physical phenomena at the distribution level. Micro-PMUs will furnish the data needed for advanced applications, such as grid automation, “transactive” controls, and model-based controls. The accuracy requirements for these technologies are considerably more demanding than for transmission applications owing to the unique characteristics of distribution circuits. For example, the relative phase angles between two points in the distribution system are smaller when compared to the transmission system, primarily due to the fact that distribution lines are shorter. Voltages must also be known with high accuracy because distribution circuits often have to control voltage levels to within a fraction of a percent. Advanced Research Projects Agency-Energy (ARPA-E) is currently funding research in remote data aggregation and advanced software algorithms to extract useful information to support utility operations.[9] The development and widespread use of micro-PMUs and other distribution sensors promise numerous benefits and will enable advanced capabilities for diagnostics, state estimation, and control closer to the customer.

Equipment and Asset Sensors

In addition to the development of more cost-effective PMUs, micro-PMUs, and other sensors that measure electrical parameters, there is an opportunity for advanced sensor technologies that allow utilities or system operators to monitor the health and utilization of grid components. These sensor technologies would provide configuration and/or real-time condition information on field assets. Data from these sensors can be integrated with advanced applications to help map and update the topology of transmission and distribution systems, determine asset status for more optimal operations, support better state estimation, and enable more complex real-time controls.

Physical limits for grid components and equipment are generally a function of operating conditions, including the ambient environment, which are dynamic. However, electrical loading and power ratings are set to accommodate the full range of conditions that grid assets will experience (e.g., maximum ambient temperature and dynamic stability issues). Grid operators adhering to these conservative ratings can leave wide operating margins that represent underutilized capacity. Real-time monitoring of equipment can help increase asset use while maintaining reliability, forestalling the need to build new capacity. Investments in sensor technology and advanced applications are minimal compared to investments in new equipment. One application based on this concept is dynamic line rating.

Another emerging concept in power systems operations is that of condition-based maintenance. This approach uses data from field sensors and operations to forecast the need for additional or future maintenance. Having specific information for each piece of equipment can be used to plan maintenance as needed, as opposed to using a fixed interval maintenance schedule. This eliminates unnecessary labor and travel for maintenance personnel, reducing maintenance costs for equipment owners.

The status and applications of several of these equipment sensors are summarized in Table 3.E.2.

Other equipment sensor opportunities include technologies to monitor electrical loads within residential homes, industrial facilities, and commercial buildings. Improved visibility into the status and health of the various loads and equipment residing within buildings and industrial plants can be leveraged for advanced control or energy management. Intelligent sensors for distributed generation, energy storage, electric vehicles, and other DERs can help optimize their performance as well as facilitate their integration.[11]

Sensor Integration

Consideration of the intended applications at the design stage can make next-generation sensors more compatible with a range of strategies and approaches downstream. Understanding sensor integration requirements is also necessary to ensure that secure and low-latency communications channels (e.g., private or public) are available to handle the new data streams. Apart from the physical development of sensors, new algorithms and data verification protocols should be developed in parallel to ensure that requirements for the sensor are appropriate and effective. For more advanced applications, there may be a need to interact with multiple sensors simultaneously and have the ability to distinguish between them. It is also important to consider the cost of ownership associated with using advanced sensors, such as PMUs, especially the costs associated with maintaining and storing the large amounts of data. Generally, communications and data management requirements—such as transfer rates, latency, accuracy, and storage—must link to applications and the type of decisions that will be made.

As advanced sensors are developed and deployed, they will augment an array of traditional sensors and systems. This patchwork of sensors can operate on differing timescales (e.g., measurement intervals), with different protocols, and have varying levels of embedded intelligence. The result will be an assortment of message lengths, data sizes, and requirements for various applications, which may be more effectively transported via one communications method versus another. The characterization, identification, harmonization, and coupling of sensors with appropriate communications technologies, proper cybersecurity measures, and common data architectures will be needed to better align IT, SCADA, and other operational technologies. Some of the potential metrics for assessing advances in sensor technologies include cost, life span, maintenance requirements,

Table 3.E.2 Advanced Sensors and Applications[10]

Area	Componemt	Sensor	Application	R&D	Demo
Substations	Substation Wide	Antenna Array	Location and identification of discharging components	X	X
		On-line Infrared	Automated processing of video thermal images of components	X	X
	Transformer	MIS Gas Sensor	Low cost sensor to measure H_2 and C_2H_2 in headspace and oil	X	X
		3D Acoustics	Location and analysis of discharge activity in transformers		X
		Acoustic Fiber Optic	Identify low level internal discharges in high risk regions	X	
		Gas Fiber Optic	Identification of gassing in high risk regions	X	
		On-line FRA	Continuously monitor frequency response using natural transients		X
	Load Tap Change	LTC Gassing	Identifying overheating or coking or worn contacts	X	X
	Post and Busing External Insulation	RF Leakage Current	Identification of high risk insulation requireing washing	X	X
	Disconnect	RF Disconnect	Identifies high risk contacts wirelessly	X	X
	CTs andPTs	RF Acoustic Emissions	Demonstrating wireless mesh to identify internal discharges wirelessly	X	X
	Breaker	RF SF_6 Density	Demonstrating wireless mesh to trend SF_6 density wirelessly	X	
Underground Lines	Oil	MIS Sensor	Low cost sensor to measure H_2 and C_2H_2 gases in oil	X	
	Underground Cable System	Various	Development of a vision document identifying potential applications and prioritizing research	X	

Table 3.E.2 Advanced Sensors and Applications[10] (continued)

Area	Componemt	Sensor	Application	R&D	Demo
Overhead Lines	Compression Connector	RF Temp and Current	Measures connector temperature and current to determine risk and identify high risk components	X	X
	Conductor	RF Temp and Current	Measures connector temperature and current for rating	X	X
	Insulator	RF Leakage	Identification of high risk insulation requiring maintenance		
	TLSA	RF Leakage	Assesses condition and number of operations	X	
	Shield Wire	RF Fault Magnitude and Location	Determine location and magnitude of fault current	X	
		RF Lightning	Distribution of lightning current magnitudes	X	
	Structure	Sensor System	Integrates RF and Image Recognition Sensors to investigate transmission line issues	X	X

Key: **TLSA** = Transmission Line Surge Arrester; **RF** = Radio Frequency; **CT** = Current Transformer; **PT** = Potential Transformer; **MIS** = Metal Insulator Semiconductor; **LTC** = Load Tap Changer; **FRA** = Frequency Response Analysis

communications requirements, ease of installation, adaptability to design changes and improvements, retrofit compatibility, and requirements on human data processing. Future research areas in sensor integration could include a "standard modular sensor package" for deployment at substations, improved real-time monitoring and analytics across the grid with a variety of sensors, and faster and more efficient algorithms.

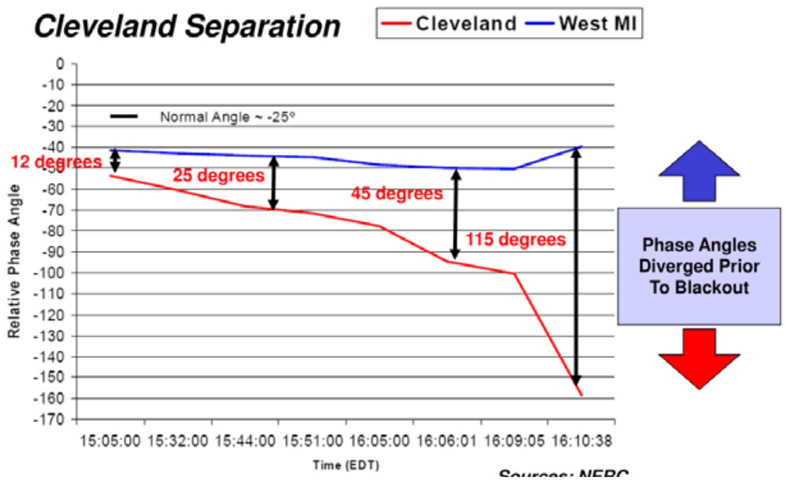
Communications and Data Management

The Northeast blackout of 2003 highlighted the extent to which the power system has become interconnected over time and the significant effect that the resulting interactions could have on reliability across regions. The outage affected an estimated 50 million people and 61,800 megawatts (MW) of electric load; some parts of the United States remained without electrical power for up to four days.[12] PMUs provide GPS time-synchronized, high-resolution data of the instantaneous voltage, current, and frequency at specific locations in the electric power system. These measurements represent the "heartbeat" of the system and can be used to calculate phase angle differences, giving an indication of the health of the electric power system.[13]

Phase angle separation between two points in the system is an indicator of grid stress that can lead to wide area outages. Figure 3.E.4 shows the phase angle separation that occurred shortly before the 2003 blackout and what the operators could have observed had the technology been in place at that time. PMUs and other sensors are foundational for advanced applications, such as wide-area situational awareness, state estimation, monitoring system dynamics, and validating system models. However, without a sufficient density of PMUs and a robust network of sensors, many of the advanced applications would not be possible and control of the grid would remain inadequate.

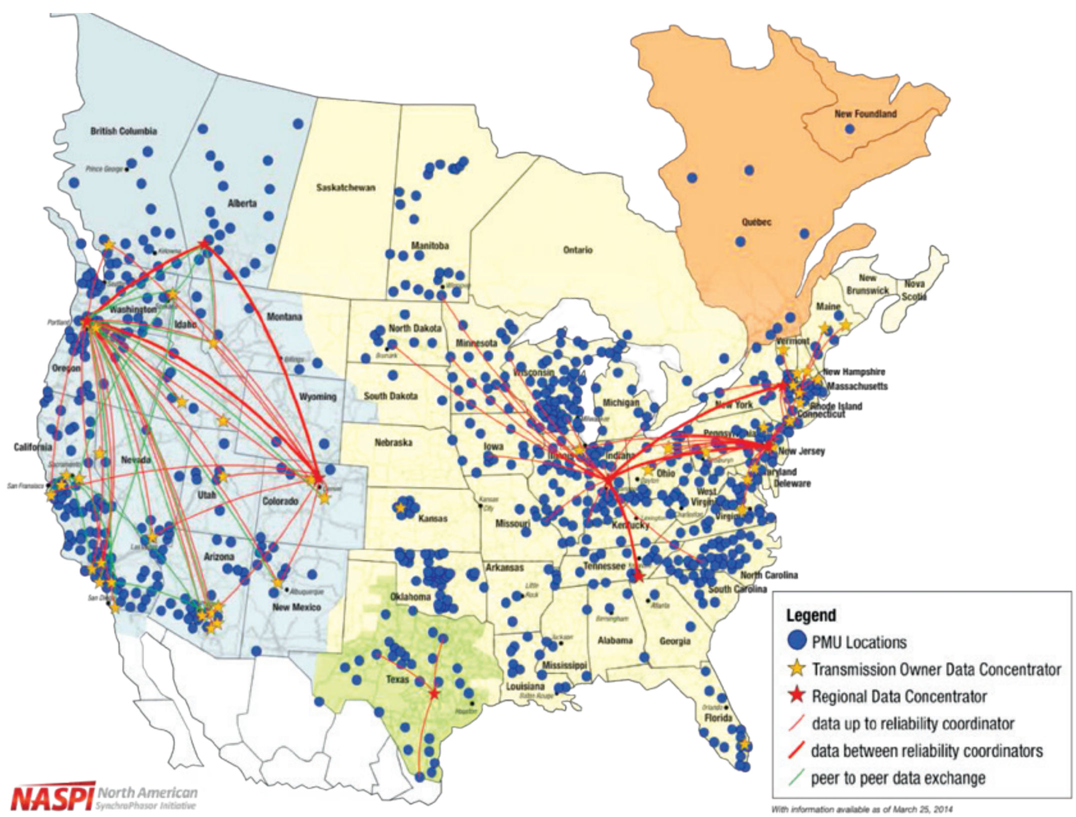
Figure 3.E.4 Example of Analysis using Synchrophasor Data: August 14, 2003 Blackout

Credit: North American Electric Reliability Corporation



While advances in sensors are foundational for improving system control, reliable communications networks and the efficient transport and management of sensor data are also critical for advanced applications. The greater use of equipment sensors, PMUs, and smart meters has resulted in a sharp increase in the amount of data that is being made available to system operators and utilities. Figure 3.E.5 shows the communications networks used to deliver data between PMUs and operation centers, where the information is displayed to help operators better understand and respond to grid conditions. This trend will continue to grow rapidly as smart devices further proliferate into the grid.

Figure 3.E.5 Data Flows from Transmission Owners to Regional Hubs, Between Reliability Coordinators, and Between Transmission Operators[14]



In addition to ensuring that vital sensor data is made available to system operators in a timely manner, communications and data management technologies must be adapted or developed to address the potentially large influx of data and effectively use it to improve decision making. Data transport from sensors to the operating environment must be viewed as one part of a larger MCC strategy. Currently, many utilities have inadequate connectivity between control rooms and their field assets, which includes substations and various sensors. Meeting the evolving needs of the grid will require reliable and cost-effective communications platforms and data management technologies that meet application latency requirements and are compatible between diverse products and users. The processing and filtering of continuous data streams, in order to identify and maintain what is useful, is an area of critical research in this data-rich environment.

Communications Platforms

Collecting data from sources distributed across the grid through existing communications channels is challenging. The information relevant to a control action may originate from a variety of sources that are far apart and that have different latency requirements and data transfer rates. Data collection and aggregation necessary for applications may involve various levels of automation, different collection and storage mechanisms, and use of different formats and protocols. Beyond the issues associated with current communications platforms, there are significant challenges for the future grid with accurately handling multiple streams of synchronized, high-speed, high-volume measurements from an array of advanced sensors. Conventional metrics like bit error rate can be used to evaluate the communications and data errors associated with new technology. A detailed survey and assessment of current utility practices and standards for communications protocols, technologies, and platforms will be valuable for guiding future system designs.

Communications infrastructure is an essential component of grid control systems because it provides the critical data-link for feedback and status updates from distant sensors and it also carries command signals to controllable assets in the field. Applications such as wide-area situational awareness of transmission lines and assets require high bandwidth communications that are fast (within a second), while protective relaying requires responses that are much faster (within milliseconds). Other than being fast and reliable, the communications platform must also be secure. Due to the essential nature of communications for control, security against malicious interference with data transfers is essential to the security of the grid itself. Additionally, security technologies that prevent unauthorized access to data are important to ensure customer privacy.

Another aspect of secure communications is the ability to maintain reliable connectivity under both normal and degraded system operating conditions (e.g., electrical noise, equipment failure, and physical attacks). In this regard, the gradual evolution of communications networks presently used by utilities may not be adequate. Additionally, the use of multiple communications technologies (such as advanced wireless, fiber optics, or other high bandwidth communications techniques) introduces challenges with diverse network architectures and mixed protocols. This issue gets more complicated with new customer technologies that can interact with the grid. Currently, technologies such as ZigBee, 6LowPAN, Z-wave, and others are used to interface with appliances and in-home sensors. Subsequently, data from these technologies can flow from smart meters to utility data servers through conventional cellular technologies or the Internet. Home area networks (HANs) could emerge as another key research area in the future.[15] HANs are required in the customer domain to implement monitoring and control of smart devices and to implement new functionalities like demand responses and seamless integration with advanced metering infrastructure. Utilities and system operators who face these challenges will need to balance system security, interoperability, and overall costs.

Data Management

Beyond the communications security concerns, data management (the transport, storage, processing, and analysis) of sensor data for system operations can present considerable challenges. Compared to even a few years ago, the amount of data transmitted to a grid management system is large, and it is still growing. Data transmitted to such systems can get lost or corrupted en route, which may require statistical smoothing, correction, or other compensation processes, delaying control response times. Timing errors ("data skew") between physically separated measurements are increasingly taken into account by time-stamping of data at the source (using technologies such as GPS). PMUs were among the first sensors to rely on accurate time-stamping; however, occasional or systematic errors in time-stamping can render PMU data useless or even potentially harmful. The security and integrity of time signals are therefore of high importance and concern. Other sources of error that need to be addressed include the steady state and transient limitations of actual sensing devices, sampling errors within the sensors, electrical noise, filtering, "aliasing" of sampled data, and the processing methods used.

Sensors such as PMUs and the related technology of digital fault recorders are changing the way utilities monitor and protect their systems. Networks have been built that move large amounts of data rapidly and securely from remote locations, with measurements taken to central locations where they are used and stored (storage allows for post-event analysis). In most instances, PMUs generate a vast amount of repetitive data, indicating normal operation that is stored, but only data under anomalous conditions is of real interest. These large quantities of data will also need to be analyzed if they are to be used in automated controls or to inform human actions. When a human system operator is involved, there is serious concern with data fatigue and overwhelming the individual with excessive information. New technologies that automatically filter and convert data into information that operators can use or organize data into databases that analysts can study will be valuable. Recent developments in "cloud"-based storage and high-speed computing may help with some of the data management challenges. However, it also raises questions about the ability to maintain the security of large databases with sensitive information that reside in publicly accessible cyberspace.

Research topics in data management for the grid can be classified under three broad categories: data analytics, data synthesis, and data visualization. Some potential projects for the various categories are highlighted in Table 3.E.3. Currently, there are efforts underway that address challenges in these research areas. The North American SynchroPhasor Initiative (NASPI) is a collaborative effort among DOE, the North American Electric Reliability Corporation (NERC), and North American electric utilities, vendors, consultants, federal and private researchers, and academics. The NASPI community is focused on advancing the deployment and use of networked PMUs, encouraging data-sharing, supporting the development of applications, and conducting research and analysis. NASPI task teams are pursuing activities to address data management challenges associated with PMUs, which can be leveraged for future applications.

Communications Protocols

Communications protocols and data transfer techniques used by information technology (IT) and operation technology (OT) equipment are often proprietary and vendor-specific. Such interoperability issues have been

Table 3.E.3 Research Opportunities in Data Management of Sensor Data for Power System Operations

Research Area	Research Project Example
Data Analytics	Research on latency and data transfer corruption issues
Data Analytics	Concept of "data fusion," which attempts to translate the enormous volume of grid data into actionable input for human operators
Data Visualization	Developing a scalable cyber-physical operating picture of the grid to improve situational awareness and operator decision making

the focus of discussions in standards organizations. The utility industry began addressing the proprietary communications issues many years ago. This led to the replacement of custom SCADA protocols with Distributed Network Protocols and to the development of International Electrotechnical Commission (IEC) standards, especially the IEC 61850 family, which are communication protocols for substation automation.[16,17,18] These standards evolved from the collaborative efforts of the United States along with the other member countries of IEC. More recently, establishment of the industrial wireless standard ISA100 is a clear example of how vendor proprietary protocols and system offerings may be combined into a suite of interoperable products that are suitable to both utilities and suppliers.

Despite the progress discussed above, continued efforts are needed to address the broad range of issues associated with diverse communications protocols. Under ARRA, DOE supported several projects that upgraded utility communications networks to accommodate new sensors and future control applications. Under these projects, new network architectures and protocols were developed to provide a seamless, multimodal (wired, wireless, and optical) suite of interconnected communications systems. In the future, data compatibility and exchange are likely to emerge as major challenges for implementation of smart grid capabilities.[19,20] Currently, smart grid technologies use different data repositories with diverse forms of structured and unstructured data. A universally compatible communications protocol should be developed to handle these diverse data forms.

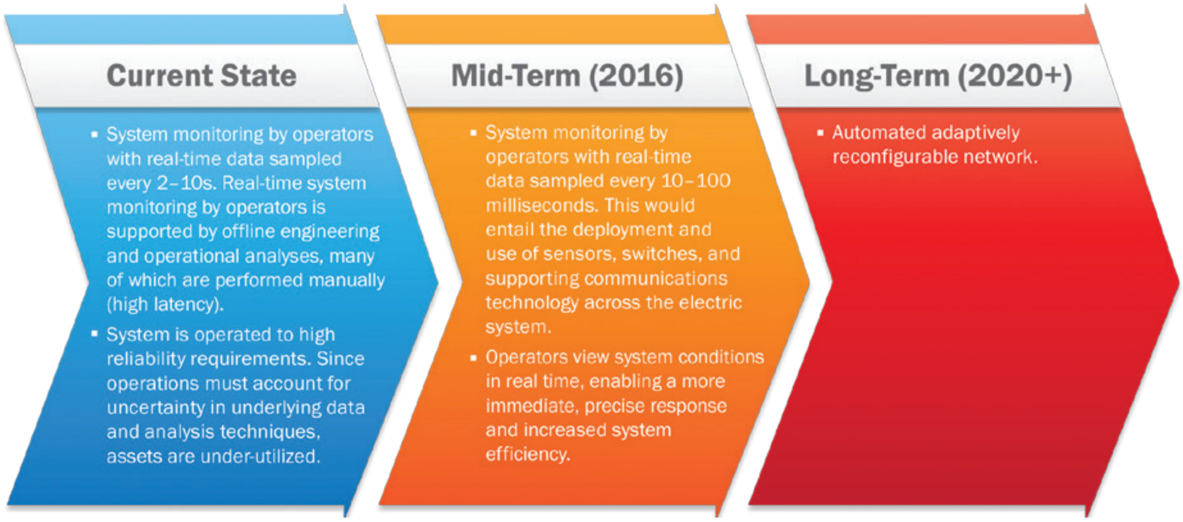
Control Systems and Applications

The successful operation of the electric power system requires a real-time balance between the amount of electricity being generated and the amount of electricity being consumed (including losses). This balance must be achieved while adhering to constraints imposed by physical limits, reliability considerations, and the limited control capabilities available to operators. To ensure this balance, grid operators continually monitor the status of the grid and take actions to ensure system stability and reliability. Control systems, such as energy management systems (EMSs) and DMSs, integrate sensor data, communications technologies, computational hardware, and software tools to enable advanced applications. These systems serve as the operators' primary interface to the grid and can be considered to be the brains behind the safe, reliable, and cost-effective operation of the electric power system.

Evolving technical requirements, rapid changes in available technologies, and fundamental changes to power system dynamics are creating the need for innovation in grid management systems. However, making advances in these technologies presents unique challenges. The computers and communications networks that support grid control systems must always be available. They cannot be patched or upgraded without extensive testing and validation, normally planned weeks or months in advance, to ensure that the changes do not jeopardize power system operations. Often, the vendor's warranty for these systems prevents the change from being implemented at all. Additionally, some of the current control systems comprise legacy technologies with limited computational power and data handling bandwidth. Some aspects of these systems were designed when the Internet did not exist and cybersecurity was not a concern.

Data streams from advanced sensors such as PMUs can be used to improve the efficiency and reliability of operating the grid. They can be used in real-time monitoring and controls, or they can be used in off-line applications, such as validating system models, operations planning, or diagnostics and post-event analyses. When these data streams are combined with software developments, next-generation algorithms, and improved computational capabilities, advanced applications such as "faster than real-time" state estimation, predictive controls, and rapid contingency analyses can be realized. Sensor data from equipment monitoring can also be integrated into control systems by tracking risks of failures, real-time physical limits, and other phenomena. Figure 3.E.6 illustrates potential operational improvements that can be realized through advanced control systems. From a long-term perspective, grid operation is likely to evolve into a paradigm with "automated

Figure 3.E.6 Pathway for Grid Operations[21]



adaptively reconfigurable networks." Such a system will have the capability to prevent failures before they occur by changing topologies or protection settings in response to accurate, fast, and predictive analytics.

Smart grid applications have the potential to provide over $63 billion in annual benefits to society by 2019.[22] Through the Smart Grid Investment Grants under ARRA, various utilities deployed PMUs on their transmission system and investigated new applications and implications for future EMSs. The grants also helped to deploy many enhanced control capabilities on distribution systems, primarily automated switches and capacitor banks, which required integration with DMSs. Some projects also explored the integration of smart meters with OMSs for improved situational awareness and demonstrated accelerated restoration after an event.[23]

More DMSs are being deployed in utility distribution control centers to improve operations, but the capabilities of these systems are very limited. There is currently little need for sophisticated systems because of limited data flows and little to no control of nonutility equipment. However, this is rapidly changing owing to the potential growth in distributed generation, more interactive and responsive loads, and electric vehicle charging that will make distribution systems more complex. Furthermore, the operating model for a majority of utilities is based on radial distribution feeders. This design concept assumes a one-way flow of power, from substations down to loads, and is rapidly becoming outdated. The implications of this old paradigm extend to operating constraints and protection strategies that must change to accommodate reversed power flows from high penetration of distributed generation.

Innovative and enhanced software applications present some of the greatest opportunities for improving grid control systems. These technologies and tools help operators interpret data, visualize information, predict conditions, and make better and faster control actions. From state estimation and contingency analysis to dynamic line rating and security-constrained economic dispatch, software applications assist operators in optimization decisions and ensuring the grid is managed safely, reliably, and cost-effectively. Due to the growing complexity and uncertainty in the system, risk and stochastic principles need to be incorporated into future applications. This differs from current applications, which are often based on deterministic forecasts that produce deterministic results. Furthermore, traditional applications are based on linear models of the grid and linear system dynamics that may no longer be accurate. Advanced algorithms and the use of nonlinear models can be applied to software applications to produce results with higher fidelity.

In support of foundational improvements to all grid control systems, DOE's Advanced Grid Modeling Program is focused on leveraging fundamental advances in mathematics and computation for power system applications. This program supports advancements in computing infrastructure, algorithms, and software tools. ARPA-E's Green Energy Network Initiative (GENI) program has also supported several projects that leverage advanced computing capabilities for the purpose of optimizing power flow. [24] These projects have ranged from integrating forecast uncertainty into operations planning decisions to enabling more efficient and reliable resource schedules to alleviating system congestion and overloads through dynamic topology reconfiguration. All these innovations support advancements that are critical for the next-generation of grid control systems.

Fast and Predictive Analytics

On September 8, 2011, a system disturbance in the Pacific Southwest led to cascading outages and approximately 2.7 million customers without power, some for up to 12 hours.[25] The speed of the 2011 Southwest blackout, illustrated by the sequence of events in Figure 3.E.7, highlights the need to provide operators with actionable information within the time frame of disturbances. In today's practice, while system data may arrive every 2–4 seconds, the calculations needed to estimate the state of the system and assess possible contingencies can take from minutes to hours. In the case of severe disturbances, the electric power system could transition to an unstable state within seconds, making it extremely challenging for operators to act without decision-support capabilities. Responding quickly to grid events, which may occur in fractions of a second, is critical to ensuring reliability and stability. The speed of advanced sensors and communications technologies can make it possible to take corrective action before a disturbance cascades into large blackouts. However, this capability will require associated advances and acceleration in computational and analytical methodologies.

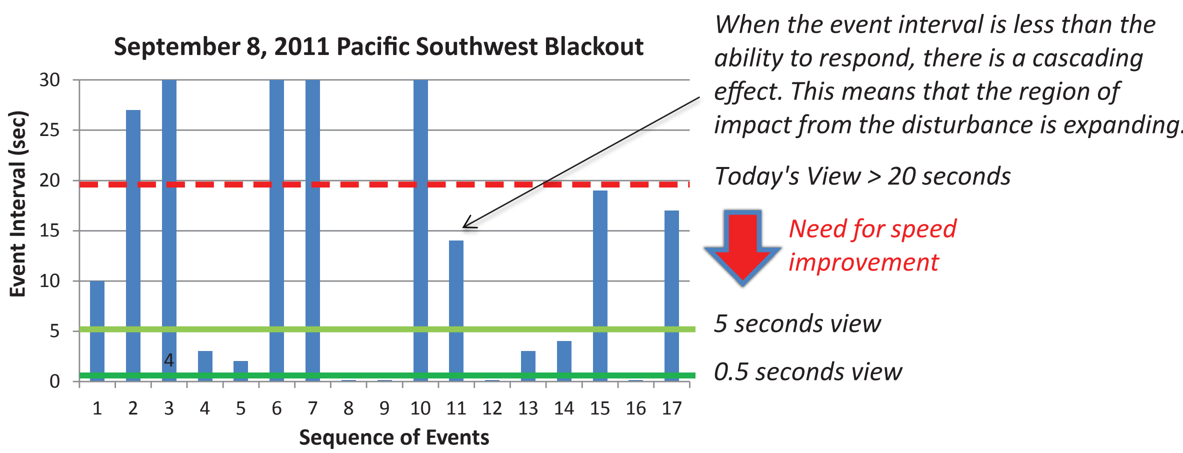
The need for fast and predictive analytics is further amplified by growing security challenges, such as physical attacks or cyber-assaults on critical infrastructure. Effectively responding to these events will require linking real-time situational awareness tools with faster-than-real-time analytical capabilities to support evaluation of potential risks and contingencies, as illustrated in Figure 3.E.8. In the emerging operational environment of electricity delivery systems, security and observability are closely coupled. Development of robust real-time control systems—built on a strong foundation of measurements and models—is a key step towards detection and mitigation of security challenges. As system complexity continues to grow, automated control systems will become essential, and coordination of protection schemes across the system will also be needed.

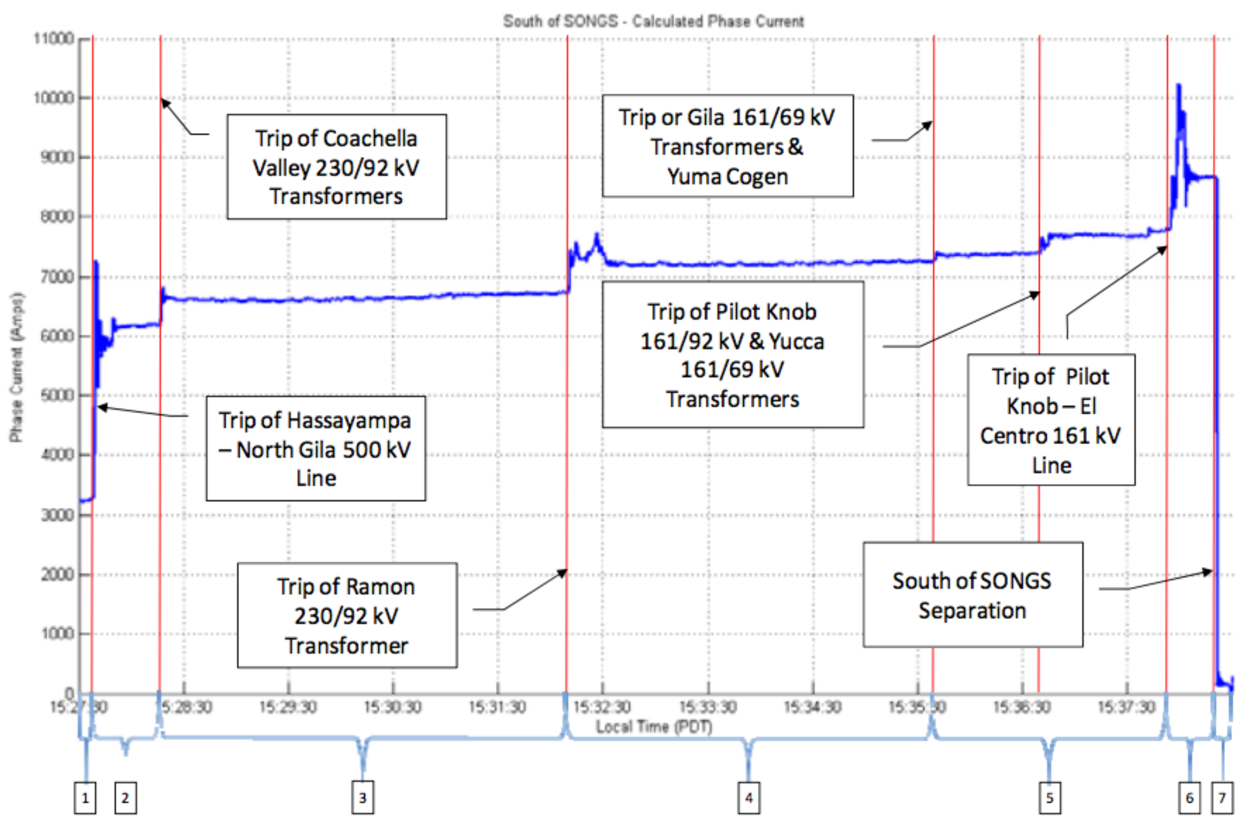
Development of applications that support dynamic look-ahead and predictive capabilities will create a new paradigm for grid control systems. However, the size and speed of data that need to be processed for these applications is limited by the underlying computational capabilities used. Recent advances in high performance computing and parallel processing can be applied to a range of power system applications. New algorithms that leverage these advanced computing platforms can enable order-of-magnitude reductions in the time required to process grid measurements and produce results.

An emerging application for fast and predictive analytics is that of stochastic unit commitment and dispatch scheduling.[26] Currently, grid operators rely on deterministic models and associated tools for planning purposes. This approach does not adequately account for load uncertainty, random generator outages, and uncertainty from the variability of wind and solar resources, among other factors that can change over time. Stochastic approaches that incorporate these underlying uncertainties into problem formulation can arrive at economic dispatch schedules that are more optimal. However, current stochastic methods and approaches take significantly longer computation times than deterministic methods and require acceleration. Other research areas that can benefit from fast and predictive analytics include improving operations planning for fuel scheduling, interchange scheduling, and day-ahead markets as well as optimization algorithms for these various functions. Incorporating wind and solar photovoltaic generation forecasting into EMS and DMS applications can support the integration of variable renewable resources.

Figure 3.E.7 Sequence of Cascading Events in the 2011 Southwest Blackout

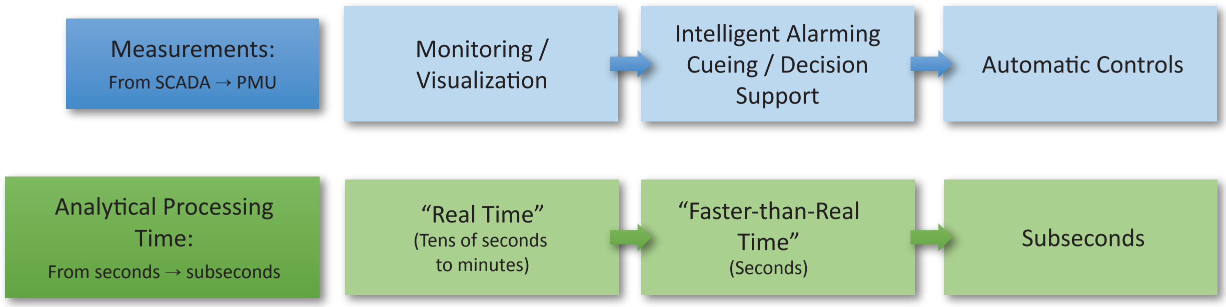
Credit: (top) Pacific Northwest National Laboratory, (bottom) FERC/NERC Staff Report on the September 8, 2011 Blackout





Disturbance Phases

Figure 3.E.8 Pathway to Speed Improvements in Analytical Decision Making



Human Factors for Improved Operations

Accelerating the analysis run-time through algorithmic parallelization and model reduction/relaxation has been successfully demonstrated in the laboratory setting and holds promise for more robust control approaches and scalability needed for future grid control systems. However, these speed benefits are still constrained by the operator's ability to visualize and respond to an event, which is typically on the order of tens of seconds to minutes. To address this issue, there is a need for cognitive models of operator behavior that capture the decision-making process from a human point of view. This forms the basis for visualization and intelligent alarming so that operators are not overwhelmed with information, can easily ascertain the source of the problem, and can effectively mitigate the situation as appropriate.

Human factors play a critical role in the successful operation of grid control systems. However, there are currently no clear or appropriate metrics for assessing the impact of human factors in enhanced grid control technologies. Concepts and metrics, such as decreases in operator error and the quality of actionable information presented to grid operators, are possible ways to assess the benefits of human-factors research in emerging grid control systems.

Distribution Automation and Outage Management

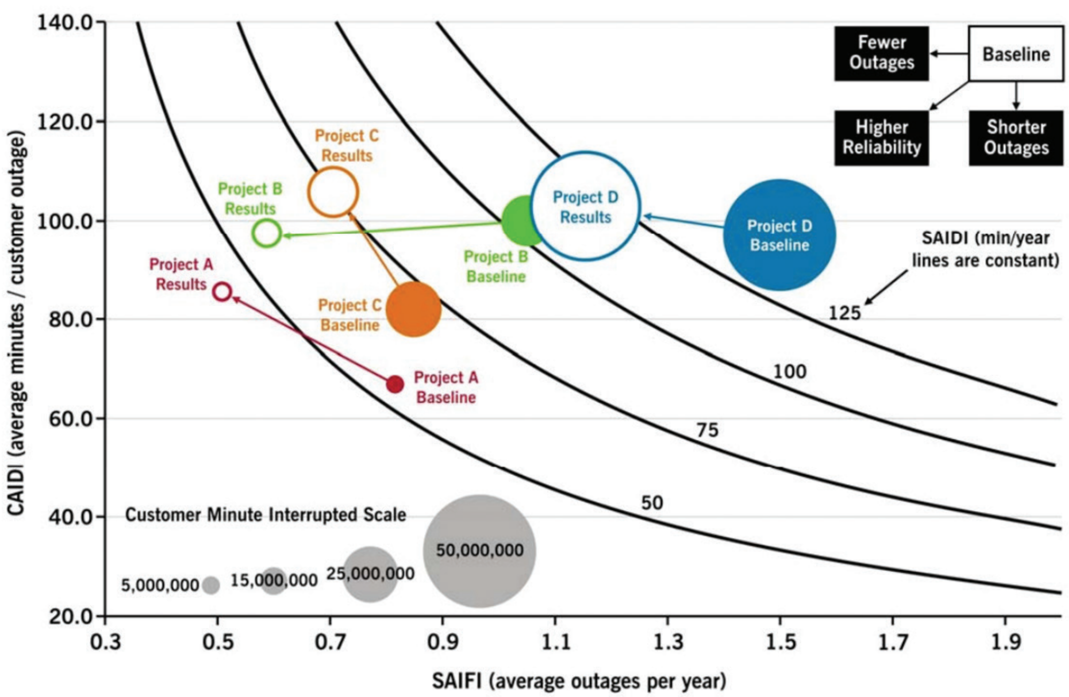
While EMSs evolved to support monitoring and control of the transmission system, DMSs evolved separately to perform similar functions in distribution systems. EMSs are much more technically sophisticated compared to DMSs due to requirements for handling market operations, performing calculations on highly networked systems, and coordinating resources over a wide geographic area. Other than EMSs and DMSs, some utilities also have OMSs to support the scheduling of equipment maintenance and to respond to unplanned outages. In many areas, utilities still rely on customer phone calls to identify and locate fallen lines and failed equipment. More recently, new control systems, such as micro-grid energy management systems and home energy management systems (HEMSs), are being deployed and can impact distribution systems and subsequently the transmission system.[27,28]

Distribution utilities are currently faced with increasingly variable and unpredictable load profiles owing to greater deployment of distributed generation, use of aggregated demand response, deployment of electric vehicles, deployment of microgrids, and more customer participation in power markets. None of these technologies and operational paradigms were anticipated when the distribution system was originally built. As the distribution system evolves and becomes more complex with the integration of advanced sensors and controllers, new technologies and tools will be needed to help operators interpret data, visualize information, predict conditions, and make better and faster control actions to ensure reliability and safety. Development of advanced DMS technologies and applications, especially to accommodate the possibility of bidirectional power flows introduced by DERs, is a critical research need.

Akin to what is currently done on the transmission system with the dispatch of centralized generators, coordination and control of various DERs (e.g., distributed generation, capacitor banks, inverters, switches, energy storage, demand response, microgrids, and smart loads) can help optimize distribution systems and ensure the delivery of reliable, resilient, and high-quality power in a changing environment. Other benefits of improved coordination and control, through next generation DMS technologies, include preventing transformer overloads, optimizing voltage profiles, and reducing switching operations to extend the lifetimes of current equipment.

Next-generation DMS applications, supported by widespread sensor measurements, can enable optimal management of the more dynamic and uncertain conditions that are evolving. Coupling high-resolution data streams with computational advances can enable faster, dynamic, and predictive capabilities. Fault Location Isolation and Service Restoration, or "self-healing," is an application that combines automated feeder switches with either distributed or centralized intelligence to clear faults and improve system reliability. Figure 3.E.9 shows the result of four Smart Grid Investment Grant (SGIG) projects that deployed distribution automation technologies. Reliability metrics generally improved, showing a decrease in System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). In other SGIG projects, the integration of smart meter and other sensor data with OMS accelerated restoration times, improving the Customer Average Interruption Duration Index (CAIDI).

Figure 3.E.9 ARRA Projects Demonstrate Impacts of Fault Location, Isolation, and Restoration[30]



Another application of distribution automation is voltage/volt-ampere reactive optimization (VVO). Measurement data is coupled with intelligence to actively control distribution devices to meet the reactive power needs of loads while maintaining voltage limits to improve power quality. Conservation voltage reduction, an extension of VVO, has been demonstrated to improve system efficiency. By optimizing the voltage along a feeder to be closer to the lower bound of voltage limits (114 V versus 120 V), it is possible to reduce energy consumption by 5%–10% and achieve peak load reductions of 1.0%–2.5%.[29] Future opportunities include integrating DERs, such as smart loads, smart buildings, microgrids, and other technologies for distribution automation, VVO, outage management, and other advanced applications.

System-Wide Coordination and Protection

New operating conditions are emerging with the addition of renewable power, distributed generation, and energy storage at the transmission and distribution levels as well as changing load characteristics. The traditional conservative operating philosophy and deterministic N-1 reliability criterion may no longer be adequate to meet reliability and resilience objectives in this new environment. Connectivity to the distribution network as well as to the consumer through smart appliances and demand response programs will expand the options available to achieve system objectives. This new operating paradigm will require improvements in control methodologies that span the entire system and can handle the probabilistic and stochastic nature of these variable and distributed resources. Broad coordination will add complexity, expand the number of control actions to be considered, and require scalability in methods to support decision making.

It will take some time before the scenario described above becomes reality, but it is likely that the DSO of the future will be required to play a far more active role in the electrical and economic management of grid assets and distributed resources. Similar to the EMS used by independent system operators (ISOs) and regional transmission operators (RTOs) in the transmission system, the next-generation DMS can help optimize operations and automate decision making in the distribution system. Additionally, the deployment of new grid technologies, especially advanced sensors, communications, and controls, is blurring the transmission and distribution boundary. If the future grid is to become an integrated platform for clean energy innovation, the future EMS and DMS will need to converge and interoperate. If resilience is a critical characteristic of the future grid, then the future OMS will also need to converge and interoperate.

Development of system-wide control and coordination approaches to protect the system from unstable conditions is a critical step to achieving this convergence. However, control schemes are fundamentally different from protection schemes, which are often local and less complicated. Reliable operation of the future system will require improved coordination between control and protection schemes to ensure new control actions are not thwarted by local protection. Additionally, the number and criticality of unstable system conditions (e.g., oscillations, voltage instability, and angular separation) are likely to increase as the grid modernizes, owing to fundamental changes in load and generation characteristics (e.g., less inertia). Research is needed for wide-area protection and control schemes that can work together to ensure safety and protection of local equipment as well as the resiliency of the power system as a whole. New wide-area system control and protection schemes will leverage the visibility achievable through PMU infrastructure and other sensor networks.

System flexibility is a broad term for the capability to manage dynamic conditions on the power system. Historically, flexibility came from a number of sources, including spinning reserves, existing generator ramping capability, power flows between balancing areas, demand response programs, and energy storage. In the near future, operators will no longer be constrained to generators, including automated governor controls and economic dispatch, as the primary means to balance the broader power system. Greater deployment of DERs, including microgrids and smart buildings, can be used to provide system flexibility. Integration of these technologies into system operations will require new control methodologies (e.g., “transactive” ones) and protection schemes that are integrated into grid control systems. The availability of other new technologies, such as power flow controllers, and the desire for increased resiliency also need to be considered in requirements for coordinated controls, protection, and flexibility.

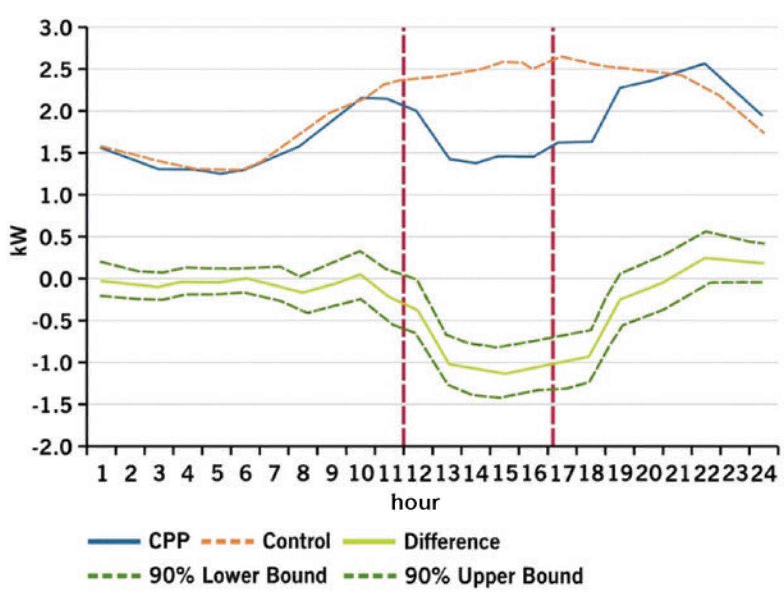
Table 3.E.4 Estimated Number of Nodes/Control Points per Entity Type for Transactive Energy[31]

Entity Type	Number of Nodes
Regional	< 20
Control Area	~200
Distribution	~1500
Market Participant	~500
Supply	~10,000
Building	~150,000,000

As the number of "prosumers" with DERs grows (potential orders of magnitude increase in control points as illustrated in Table 3.E.4), privacy concerns and communication bandwidth limitations render centralized command-and-control dispatch approaches impractical. Additionally, since most of these energy assets are owned by consumers or third-party providers, coordination with grid operations needs to appeal to the owners' self-interest (e.g., rewards for their participation). New coordination and control concepts to achieve multi-objective optimization (for both local and global objectives) across multiple actors (who may be synergistic or in competition) are needed for the future grid. Integrating the coordination of DERs with transmission system operations also poses significant challenges.

Demand response programs have been offered by utilities since the 1970s to reduce peak loads during times of system stress. The coordination and control of these resources were managed by the utility through direct control or voluntary requests to certain customers for a financial incentive. Recent experiences with aggregated demand response resources in electricity markets present a potential framework for other DERs to interface with transmission operations. However, the physical constraints imposed by current distribution system designs require careful consideration of how a larger number of DERs will need to be coordinated to ensure safety, reliability, and power quality. Effective coordination and control of these various resources will be highly dependent on the availability of intelligent devices, communications infrastructure, and distribution automation capabilities. It will also require improved understanding of customer electricity service needs, behavior, and direct benefits (such as improved comfort or preventive maintenance of electrical equipment). For example, if automated demand response capabilities can be advanced with less compromise in service to consumers, the likelihood of higher customer participation will increase.

Figure 3.E.10 Critical Peak Pricing (CPP) Demo of Marblehead Municipal Lighting Department[32]



Dynamic pricing (e.g., time of use pricing, critical peak pricing, or real-time pricing) is another approach that can be used to coordinate DERs to meet the needs of the transmission system. This incentive-based mechanism provides consumers with varying electricity rates at different times of the day to inform decisions. By using a combination of price signals with customer-interfacing technologies, it is possible to reduce system peaks at particular times to optimize system operations. Through the use of smart meters, in-home displays, Web portals, programmable thermostats, and other information and communications technologies, a customer can automatically or selectively respond to the price signals. Figure 3.E.10 shows the results of a critical peak pricing pilot demonstration. Average peak load reductions of 0.74 kW per customer were achieved, but a rebound effect may occur if too many devices are automated, as evidenced by the shift in peak load from 16:00 to 22:00. Continued efforts in developing next-generation control approaches will be needed to support system-wide coordination and protection for the future grid.

Endnotes

1 Sensors, communications networks, and control systems (IT and OT with applications) are the primary focus of this paper. Control theories and control architectures, such as transactive energy and hierarchical distributed controls, are covered primarily in the Designs, Architectures, and Concepts paper. These concepts are also briefly discussed here.

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4 Phase angle denotes the angle by which the voltage leads or lags the current in an AC circuit. If the phase angle is positive, then the voltage leads the current in the circuit. Likewise, if the phase angle is negative, then the voltage lags the current in the circuit. See Glossary for a detailed definition.

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17 For a technical overview and detailed standards provisions, refer to "Core IEC Standards." International Electrotechnical Commission. Accessed February 24, 2014: http://www.iec.ch/smartgrid/standards/.

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Glossary and Acronyms

Alternating current (AC)	An electric current that reverses its direction at regularly recurring intervals.
Advanced Research Projects Agency Energy (ARPA-E)	The Advanced Research Projects Agency-Energy (ARPA-E) advances high-potential, high-impact energy technologies that are too early for private-sector investment. In 2007, Congress passed and President George W. Bush signed into law The America COMPETES Act, which officially authorized ARPA-E's creation.
American Recovery and Reinvestment Act (ARRA)	Commonly referred to as the Stimulus or The Recovery Act, was an economic stimulus package enacted by the 111th United States Congress in February 2009 and signed into law on February 17, 2009, by President Barack Obama.
Bit error rate (BER)	The percentage of bits that have errors relative to the total number of bits received in a communication transmission.
Current (instantaneous)	The rate of flow of electrons at a point in an electrical conductor. It is measured in amperes. The instantaneous value of an alternating current is the value of the current flow at one particular instant.
Current (RMS)	The root mean square (RMS) current of an AC electric power is the square root of the mean of the squares of instantaneous value of the current. In electric power industry, the RMS values of current and voltage are widely used.
Distribution management system (DMS)	A collection of applications that acts as a decision support system to assist the control room and field operating personnel with the monitoring and control of the electric distribution system.
Distribution system operators (DSOs)	Organizations that are responsible for operating, ensuring the maintenance of and, if necessary, developing the distribution system in a given area.
DOE	U.S. Department of Energy
Energy management systems (EMS)	A computer-aided system used by electric utility grids to improve the generation and transmission system via monitoring, controlling and optimizing.
Frequency	The oscillations of alternating current (AC) in an electric power circuit. It is measured in Hertz. The frequency of AC supply in the United States is 60 Hz.
HEMS	Home Energy Management System
International Electrotechnical Commission (IEC)	A non-profit, non-government international standards organization that prepares and publishes standards for all electrical, electronic and related technologies.

ISO/RTO	In the United States, ISOs are independent organizations that are responsible for managing a regional transmission grid. An RTO is typically responsible for managing the operations of a transmission grid in a particular geographic area. ISO/RTOs can also facilitate electricity markets for the purchase and sale of wholesale power.
North American Reliability Corporation (NERC)	The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system in North America.
North American SynchroPhasor Initiative (NASPI)	A collaboration between the electric industry, NERC, and DOE to advance the use of synchrophasor technology to enhance grid reliability and economics.
Outage management system (OMS)	A computer system used by operators of electric utilities to better manage their response to customers' power outages.
Phase angle	Denotes the angle by which the voltage leads or lags the current in an AC circuit. If the phase angle is positive, then the voltage leads the current in the circuit. Likewise, if the phase angle is negative, then the voltage lags the current in the circuit.
Phasor measurement units (PMU)	Precise, real-time grid measurement of electrical waves to determine the health of the electricity distribution system.
Photovoltaics (PV)	An electronic device consisting of layers of semiconductor materials that can convert incident light directly into electricity.
Reactive power	The component of an AC electric power that establishes and sustains the electric and magnetic fields in inductive and capacitive circuit elements. It is measured in VAR.
Real Power	The component of an AC electric power that performs work (i.e., results in net energy transfer in one direction). It is measured in watts.
SGIG	Smart Grid Investment Grants
Supervisory control and data acquisition (SCADA)	SCADA systems operate with coded signals over communications channels to provide control of remote equipment of assets.
VAR	Volt-ampere reactive (var) is a unit in which reactive power is expressed in an AC electric power system. Reactive power exists in an AC circuit when the current and voltage are not in phase.
Voltage (instantaneous)	A measure of the electric potential difference between any two conductors or between a conductor and earth. It is measured in volts.
Voltage (RMS)	The root mean square (RMS) voltage value of an AC electric power is the square root of the mean of the squares of instantaneous value of the voltages.