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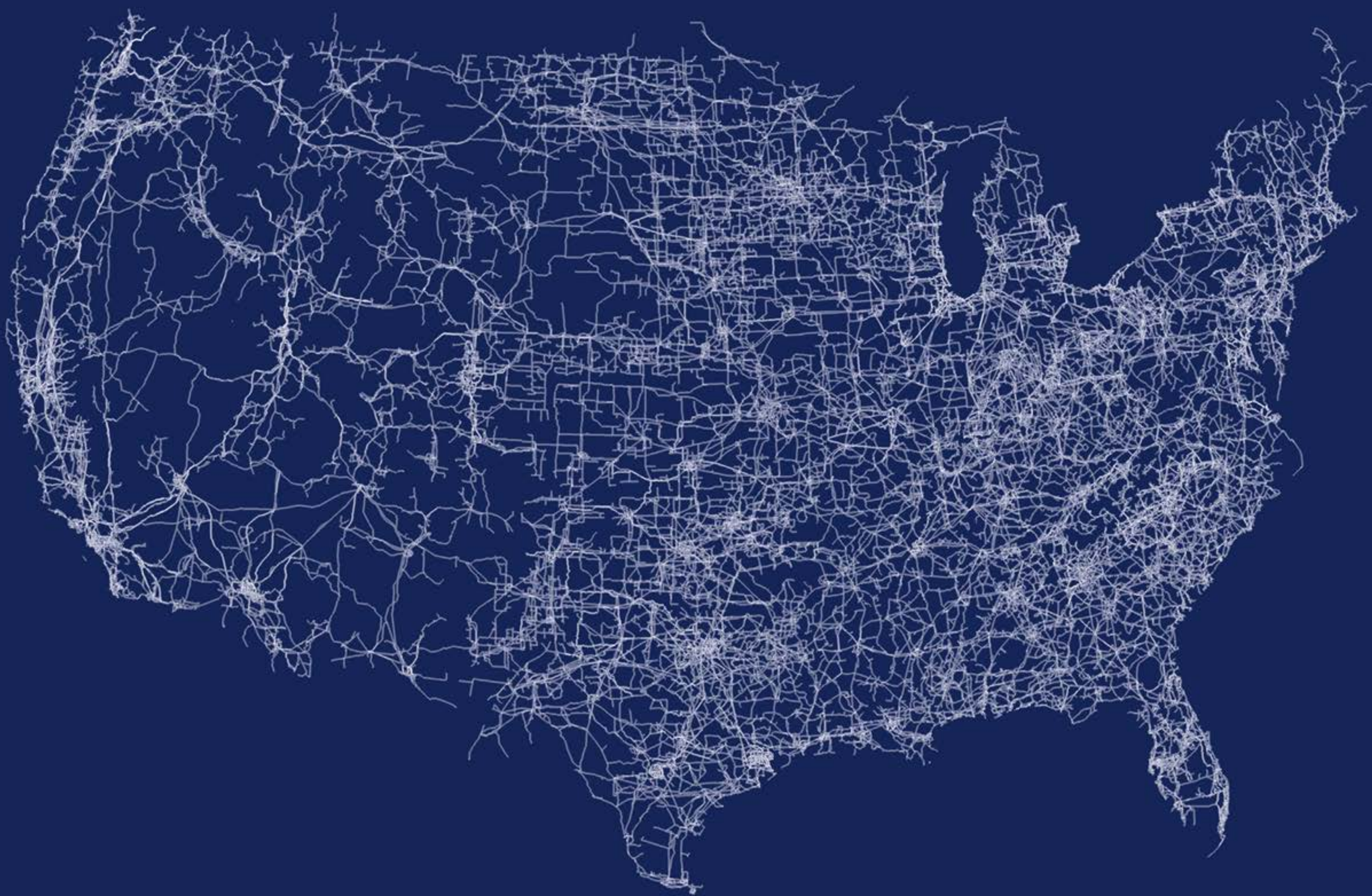

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Electricity Transmission System Research and Development: Automatic Control Systems

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Electricity Transmission System Research and Development:

Automatic Control Systems

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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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Acronyms and Abbreviations

AC	alternating current
ACE	area control error
AGC	automatic generation control
AVR	automatic voltage regulator
DC	direct current
DER	distributed energy resources
DOE	U.S. Department of Energy
EMS	energy management system
FACTS	flexible alternating current transmission systems
HVDC	high-voltage direct current
Hz	Hertz
kV	kilovolt(s)
MTDC	multi-terminal HVDC network
MVA	10^6 volt amperes
MW	megawatt(s)
NASPI	North American Synchrophasor Initiative
PACI	Pacific Alternating Current Intertie
PDCI	Pacific Direct Current Intertie
PMU	phasor measurement unit
PSS	power system stabilizer
PV	photovoltaic
R&D	research and development
RAS	remedial action scheme
SCADA	supervisory control and data acquisition
SIPS	system integrity protection schemes
SPS	special protection scheme
SST	solid-state transformer
SVC	static VAR compensator
TCSC	thyristor-controlled series capacitor
UPFC	universal power-flow controller
VAR	volt ampere reactive
VSC	Voltage Source Converter
WAMS	wide-area measurement system

Executive Summary

This white paper describes technologies that can, with prioritized research and development investment by the U.S. Department of Energy (DOE), be deployed to provide better real-time control of the U.S. electricity grid during both normal and off-normal conditions and to improve the grid's operational efficiency and resilience. In addition to describing these technologies, we provide a list of recommendations for DOE research and development investment, prioritized by timeliness and focused on the grid of the next 20 years.

This paper addresses the following topics:

- The evolution of digital controls
- Coordination among remedial action schemes (RASs) and special protection schemes (SPSs), including adaptive islanding, an advanced system integrity protection scheme that reduces the impact of an uncontrolled cascading failure during an emergency by deliberately breaking an interconnection into smaller segments
- Planning for and managing frequency response, voltage stability, small signal stability, and transient stability on a grid that has a significant penetration of inverter-based generation
- New requirements for generator (and load) capabilities to support the grid, including leveraging the faster capabilities that are enabled by power electronics

Other emerging technologies that are discussed include wide-area, real-time control involving high-speed time-synchronized measurements, and expanding control actuation capabilities to include inverter-based generation, energy storage, and other power electronics-enabled resources. We focus on how these technologies will enable enhanced system-wide control.

We also address supporting technologies, such as the need for creating advanced simulation tools to design and deploy the capabilities listed above, and discuss considerations for developing controls and protection schemes that are robust to natural or man-made threats. This includes threats that may be directed at the control systems themselves, especially cyber threats. We examine the opportunity for increased automation, or alarming/cuing and intelligent analytics, to increase operator performance during emergencies or times when staffing is short.

Finally, the paper presents prioritized recommendations for DOE to fund targeted research and development to improve understanding of the impacts of new controls.

1. Overview

The interconnected power system derives much of its reliability from its immensity, inertia, and shared reserves. In addition, significant benefits can be realized when power can be transferred economically over vast distances. This white paper describes technologies that can be deployed to provide better real-time control to improve the operational efficiency and resilience of the network during both normal and off-normal conditions, respectively.

This paper addresses the following topics:

- The evolution of digital controls
- Coordination among remedial action schemes (RASs) and special protection schemes (SPSs), including adaptive islanding, an advanced system integrity protection scheme that reduces the impact of an uncontrolled cascading failure during an emergency by deliberately breaking an interconnection into smaller segments
- Planning for and managing frequency response, voltage stability, small signal stability, and transient stability on a grid that has a significant penetration of inverter-based generation
- New requirements for generator (and load) capabilities to support the grid, including leveraging the faster capabilities that are enabled by power electronics
- Emerging technologies including wide-area, real-time control involving high-speed time-synchronized measurements, and expanding control actuation capabilities to include inverter-based generation, energy storage, and other power electronics-enabled resources to enhance system-wide control
- Supporting technologies, e.g., the need for advanced simulation tools and for controls and protection schemes that are robust to natural or man-made threats, including threats to control systems themselves (such as cyber threats)
- Opportunities for increased automation, or alarming/cuing and intelligent analytics, to increase operator performance during emergencies or times when staffing is short.
- Prioritized recommendations for DOE to fund targeted research and development to improve understanding of the impacts of new controls

The remainder of this paper is organized as follows:
Section 2 presents foundational background for our discussion of automated controls.
Section 3 discusses the need for rapid response by grid controls.
Sections 4-13 focus on the following specific sub-topics:

Digital controls for substations and power plants
Remedial action schemes
Adaptive islanding
Fact-acting devices
Control architectures for new communications and sensors

Microgrids as grid control resources
Electricity storage
Improved methods for dynamic simulation
Control capabilities to improve grid restoration/ black start after a contingency
Protection against external threats

Sections 14-15 discuss the path forward and our research and development recommendations.
Section 16 lists the references.

2. Foundational Background

There are compelling reasons for local grid controls to operate rapidly (typically on the order of sub-seconds) and global controls to operate at a slower tempo. The speed and reliability concerns associated with wide-area communications would make many forms of fast-acting controls impracticable if they were centralized. As a result, the architecture of power system controls evolved such that most wide-area controls are supervisory in nature while the fast response needed to quickly clear damaging fault currents is based almost exclusively on local measurements. Power plant controls are also local in nature. They include governors with a direct linkage between the prime mover and generator speed. The governor controls the speed of the generator prior to synchronization and provides primary frequency response after synchronization. As system frequency declines or increases, the real power output of the generator is adjusted up or down, respectively. The proportional response of how much power to change versus the frequency change is called "droop." This proportional control is necessary to ensure that parallel machines across the entire interconnected power system appropriately share the necessary power adjustments to regulate frequency. Similarly, the automatic voltage regulator (AVR) associated with generators manages excitation control. The AVR does this by regulating the field current to manage terminal voltage, which directly corresponds to the reactive power output of the generator. This control must be designed so that multiple nearby machines provide proportional reactive power response corresponding to changes in the terminal voltage. Voltage regulation is much more localized than frequency control; the latter spans the entire interconnected power system. Each of these controls operates continuously by measuring frequency and voltage and responding to the measurements by regulating the prime mover and field current, respectively. It should be noted that not every generator is required to provide this response; some generators are allowed to "lean on" the system by not supporting voltage and frequency regulation.

Supervisory controls were introduced to help regulate frequency on large, interconnected power systems. These controls gather measurements associated with tie-line flows and frequency error at a typical refresh rate of once every four seconds to calculate the *area control error* (ACE) for each of the approximately 100 balancing areas across the interconnected North American power system. The energy management system (EMS) at the control center, with guidance from other input including operational dispatch or market-based considerations, determines adjustments to specific generation units that are participating in *automatic generation control* (AGC). There are specific performance standards that each balancing area needs to meet to maintain grid frequency at near 60 Hertz (Hz) at all times.

Large perturbations that might be caused by events such as the sudden loss of a generation facility are handled by the primary frequency response associated with collective governor response. Small perturbations disrupting the balance between load and generation are continuously handled by the secondary frequency response. Tertiary frequency response is a slower form of frequency control in which resources are put in place (usually via re-dispatching generation resources, supervised by system operators) to handle current and future contingencies. Common types of tertiary response are reserve deployment and reserve restoration following a disturbance [1]. Figure 1 illustrates the relative time scales of primary, secondary, and tertiary frequency response [2]. Each location responds to perturbations in the frequency and/or voltage as observed at that location. Extreme events that might be caused by multiple simultaneous events (or a cascading failure) would be handled by emergency controls, such as automatic under-frequency load shedding. The specific settings of diminishing time delay for multiple stages of declining frequency vary by interconnection, but in North America they are triggered before reaching 59 Hz on a 60-Hz system. The goal is to prevent power plants from tripping as a result of under-speed protection.

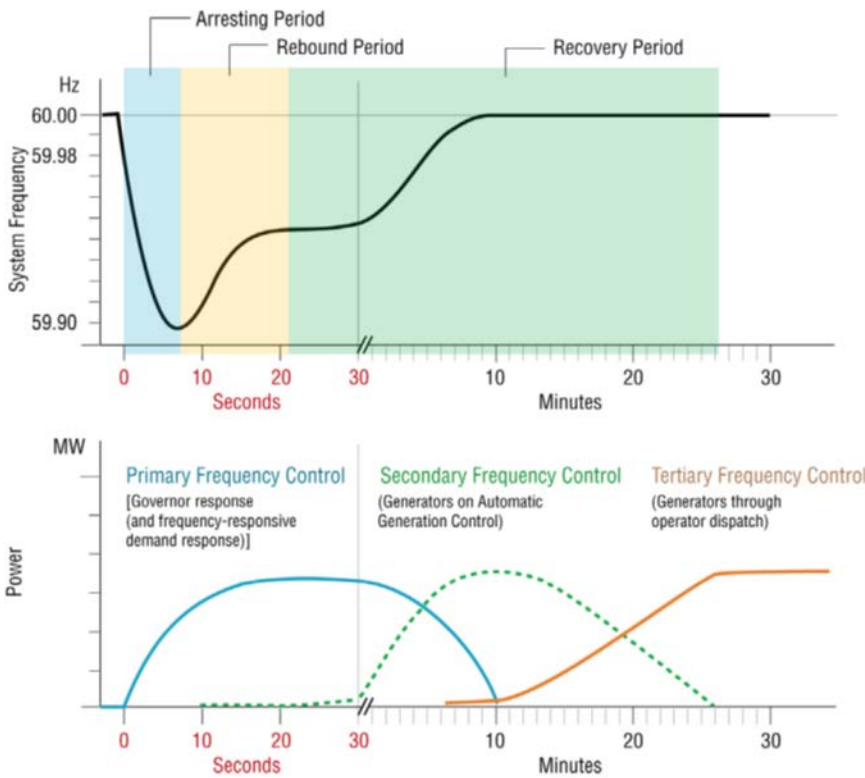

Figure 1. Time scales of frequency control actions and associated frequency response after a disturbance [2]

If communications associated with frequency response were completely compromised (i.e., unavailable), power generation facilities would continue to operate based on their last assigned set-points. System frequency would be difficult to manage, but the primary frequency control associated with individual plants would provide stable operating conditions, and governor droop control would provide proportional sharing of power changes among plants. Reliability risks would grow over time if the loss of communications was prolonged, but the system itself could continue to operate without centralized control.

3. The Importance of Fast Response

Out of necessity, protection systems need to function quickly to sense an abnormality, decide what action to take, and execute the selected action to clear the fault. Damaging fault current associated with a short circuit would destroy equipment if allowed to persist for too long. Also, fast fault clearing provides stability benefits, particularly for extra-high voltage transmission. Critical clearing times are often a prime consideration for establishing the ratings of stability-constrained transmission lines. Development of fast circuit breakers that can clear a fault in a small number of 60-Hz cycles enabled the deployment of extra-high voltage transmission in the mid-20th century. There was a natural incentive to develop technology that could clear faults more rapidly in order to enable higher power ratings on constrained pathways. Fast-acting protective relays were also important because they minimized the overall time required for protection. Most modern protective relays can make a determination in about 5 milliseconds (excluding intentional time delays to ensure selectivity through coordination). Some more modern advanced protection schemes, which are based on traveling wave fault detection and location technology, are able to make a determination in as little as 2 milliseconds [3].

Figure 2 is a spatial-temporal graph showing most of today's grid control systems, which occupy one of two extremes. Based on supervisory control and data acquisition (SCADA) measurements, control center EMSs optimize global objectives such as minimizing power loss and generation cost. However, these global control schemes are generally slow, open loop, and involve humans. At the other end of the spectrum, fast time-scale controllers such as relay systems lack a global perspective and usually operate in a local, decentralized manner. The green box in Figure 2 represents an alternative that is quickly becoming feasible as a result of the rapid deployment of wide-area networked measurement systems, including phasor measurement units (PMUs) and fast power-electronic-connected resources (e.g., photovoltaic [PV] generation, energy storage technologies). The proliferation of these networked distributed energy resources (DER) can be leveraged to design coordinated controllers that use real-time feedback and act on a time scale of sub-seconds to tens of seconds, for grid-scale controls that combine the advantages of global and fast control mechanisms.

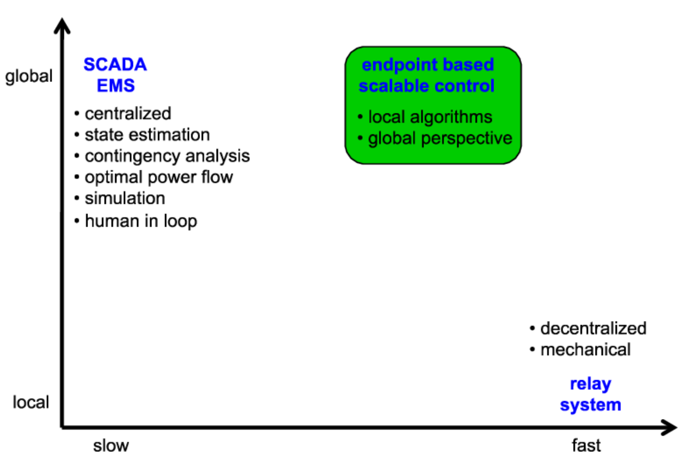

Figure 2. Spatial and temporal scales of current controls and proposed (green) controls

A key challenge in the near future will be developing advanced control schemes that can harness the system-level benefits of these fast-acting technologies. One aspect of the challenge is associated with the speed of communications and computation, and another aspect of the challenge is the need for robust communications that will deliver signals over wide areas with high levels of integrity and availability. We believe that the biggest aspect of the challenge will be the design of the control systems themselves. Control systems must be designed in such a way that they operate reliably under normal conditions but are also able to anticipate and act appropriately during highly unusual circumstances. Unusual circumstances could include failures in the communication system, so appropriate failsafe designs must be baked into the control logic. Unusual circumstances could also entail topology or other conditions that have not been previously encountered. These control systems must not introduce too much unnecessary complexity that will become challenging during these off-normal conditions.

4. Substation and Power Plant Digital Controls

The first generation of substation and power plant control automation replaced analog equipment with digital controls that emulated the actions of the analog components that they were replacing. For example, a digital device that could be programmed to mimic the characteristics of an electromechanical relay built with Swiss watch precision and based on magnetism and spring tension. More functionality could be included in the digital device, such as enabling a protective relay to also serve as a fault locator. Such a device could store and transmit oscillography associated with the fault, enabling the relay to conduct self-diagnostics, and settings could be updated remotely. Benefits continued to accrue as more and more features were included in intelligent electronic devices. As a result of this evolution, protection systems have become much more reliable, increasing the overall reliability of the power system.

Similarly, power plant controls (governors, excitation systems, etc.) were upgraded over time as newer technology became available. At first these power-plant systems were programmed to behave in the same manner as their analog predecessors, but they have gradually become much more flexible to accommodate the specific requirements of the facility in which they are programmed to operate.

As these technologies have evolved, they have leveraged advances in standardized Ethernet-based communication networks that support various types of substation and plant automation. These field bus architectures have largely replaced direct-wired sensors and actuators with controllers in substations and power plants. This has led to a tremendous benefit by reducing the cost of installation and maintenance, and, more important, has enhanced power system flexibility. It has also enabled unprecedented connectivity among subsystems and hierarchical coordination with other supervisory layers of control and data acquisition, allowing extraction of large volumes of operational and engineering data for diagnostic and other purposes. As the reliability of these field bus data architectures has increased, this has enabled new types of automated control and protection schemes to be programmed into substation and power plant digital controls.

Although the focus of this paper is on the application of wide-area controls, it is important to acknowledge the trends and advancements under way at the substation and power-plant levels. Much of the technology on which increased wide-area control will depend is similar to, and will leverage, advanced localized communication and control, which continue to evolve as common standards are adopted and interoperability increases.

5. Remedial Action Schemes

Remedial action schemes (RASs) or special protection schemes (SPSs) (also known as system integrity protection schemes [SIPS]) are wide-area controls that were introduced to ensure the stability of the grid during prescribed conditions after a contingency [4, 5, 6]. Their benefit is enabling greater power flow across paths that would otherwise need to be constrained in anticipation of credible contingencies that could destabilize the grid. Generally, a RAS is “armed” in advance, based on an evaluation of the operating conditions and the proper response that would be needed if various contingencies were to occur. The RAS operates quickly if one of those contingencies occurs. A RAS is carried out by dedicated communications signaling that action needs to be taken (for example, from the substations adjacent to a faulted element) to a centralized control center, so that prompt actions are commanded; each of these transactions can occur across vast geographical distances.

One well-known example of the impact of RASs is the Pacific Alternating Current Intertie (PACI), which was built to transfer power between the Pacific Northwest and California and forms the backbone of the western portion of the western interconnected power system. Because of the vast distances involved and lack of significant generation in the middle of this path, there are significant transient stability limitations on the rated path flows. Specifically, if a fault or other condition occurs that trips one of these transmission lines, and there is too much power flowing across the aggregate set of lines, the overall power flow must be reduced immediately. Part of the reason, which is unique to the western power system, is that the PACI, composed of multiple 500-kilovolt (kV) lines, connects the northern and southern portions of the system in parallel with other 345-kV and lower transmission in the eastern portion of the system. If the flows in the western portion of the system were not reduced quickly following a fault such as described above, the resulting power flow could overload transmission elements elsewhere in the system. The implementation of a RAS on the PACI enables a higher path power-flow rating than would be possible otherwise.

When the RAS determines that action is required following an event (which has been studied in advance), the action is carried out by reducing generation in the sending area and reducing load in the receiving area. This action is designed to prevent a cascading failure, such as overloading adjacent line(s). In the case of the PACI, assuming north-to-south power flow prior to the disturbance, this action would be to curtail key hydroelectric facilities in the Northwest and to trip water pumps associated with the California aqueduct in the southern portion of the system. Information must be collected about the event, a determination made, and control commands sent rapidly enough to arrest the next step in the cascading failure sequence that would occur without the control action.

Unique to the Pacific Northwest, the Bonneville Power Administration has a braking resistor that can switch on 1,400 megawatts of resistive load for a short period of time [7]. The braking resistor is thermally limited to an operation of no more than 3 seconds; a typical operation takes 0.5 seconds. The resistor is designed to operate quickly in the programmed sequence of RAS events; this energy helps prevent too much acceleration of generators while other controls are responding to the event.

As previously described, a RAS is "armed" based on an assessment of the desired response to a specific stimulus. This stimulus may be detecting the de-energization of a transmission facility (e.g., detecting the opening of circuit breakers), and the primary example of response would be ramping-back of generation on the sending end of the interface and curtailing load on the receiving side. One of the challenges of traditional RASs is their complexity and the need to identify myriad potential responses to an exhaustive set of potential scenarios. Because responses are armed based on studies of how the system needs to respond to projected conditions, it is difficult to properly account for all of the uncertainties involved. One enhancement that should be considered for additional research, development, and demonstration is the deployment of response-based RASs, in which a proportional response to a directly observed stimulus is programmed. For example, a scheme could be set up to curtail generation and/or load based on how much and how fast the relative phase angle changes between the sending and receiving ends of a stability-constrained transmission path. In the case of the PACI, the relative phase angle between the northern and southern parts of the western interconnected power system could be directly observed by all of the RAS actuators; all they would need to do is execute their programmed responses based on that signal. This approach would remove, or dramatically simplify, the logic tree (which requires extensive simulation and analysis) between detecting individual transmission failures and mapping those to the desired response based on predicting what that response should be. The control action associated with the proportional-response-based RAS would also be appropriate for ensuring wide-area stability irrespective of the specific sequence of events leading to the condition being observed at a given moment.

6. Adaptive Islanding

As smaller power systems were joined into larger systems over the past several decades, the interconnected system gained shared reserves and a greater degree of inertia. Today, the system derives much of its reliability from its immensity. Significant economic benefits can also be realized when power can be transferred over vast distances. However, a cascading failure on an interconnected system can also pose risk to portions of the system that are far removed from the location of the initial problem. The process of “islanding” the system, breaking an interconnection into smaller portions, can result in significant outages if it occurs haphazardly as the result of an uncontrolled cascading failure. But if islanding is pre-planned and properly managed, the impact of a cascading system failure could be significantly reduced. The goal of adaptive islanding is to preserve the benefits of large-scale interconnected system operations during normal conditions and reduce the risk of cascading failure propagation during abnormal or emergency conditions.

All large-scale blackouts have one thing in common: as the system failed, it broke into islands. One example took place on August 14, 2003 when four root causes coalesced to plunge 50 million people into the largest blackout in the history of the North American power system [8]. Customers and commerce were disrupted over an area that spanned Cleveland, Detroit, Toronto, and New York City. As the sequence of events accelerated into an uncontrolled cascading failure, individual transmission lines automatically tripped, fragmenting the system into multiple islands. Whether a specific location was importing or exporting power prior to the disturbance had a bearing on the severity of the impact at that location. During the uncontrolled cascading failure, many generators tripped, causing more load to be lost in islands that were generation deficient. Nearly all large-scale blackouts exhibit a similar pattern.

Adaptive islanding is an advanced form of RAS aimed at limiting the disruption associated with an uncontrolled cascading failure. In this approach, the islanding schemes that would be triggered in the event of a contingency would adjust based on the patterns of generation and load on the system; that is, the boundaries of the planned islands would periodically be updated as changing conditions warranted. If an adaptive islanding scheme was triggered, fast controls would cleave the system into the predefined islands. Fast-acting generator adjustments, storage dispatch, or load shedding would be necessary to maintain stability in areas that were generation deficient at the time of the event. It would be crucial to quickly match available generation with real-time load while respecting dynamic transient response characteristics.

Several research papers have proposed adaptive islanding, but wide-scale implementation will require additional development and demonstration. This approach would be easier to implement in some areas, such as Alberta or Florida, than in more tightly interconnected regions such as Ohio. If the challenges can be worked out, adaptive islanding would minimize the disruption caused by future cascading failures, resulting in a more resilient power system. This technology is described in detail in [9].

7. Leveraging Fast-Acting Devices to Enhance System Reliability

As the power system continues to evolve, many more power-electronics-based devices will be deployed, associated with the generation, transmission, distribution, and end-use portions of the interconnected system. On the generation side, wind and solar will be integrated through solid-state power electronics inverters. On the transmission and distribution systems, there will be more instances of fast-acting controls associated with flexible alternating current transmission systems (FACTS), including universal power-flow controllers (UPFCs), static volt ampere reactive (VAR) compensators (SVCs), thyristor-controlled series capacitors (TCSCs), and other similar devices [10]. There will also likely be more instances of high-voltage direct current (HVDC) transmission technologies [11]. In the distribution arena, a myriad of DER will be deployed, including small solar, batteries, and other technologies. It is anticipated that end-use loads will have greater flexibility as well, including battery charging for electric vehicles and other power-electronics-enabled devices. All of these devices have one thing in common: they have the potential to be controlled much faster than traditional synchronous machines. This fast-acting control can be harnessed for the benefit of the overall power system, but significant concern remains regarding the predictability of the response; the control algorithms (and standards) need to be further developed.

In the future, power-electronics-based devices could be remote actuators in a vast system-wide control scheme. That scheme should employ the design principles described earlier, in which fast-feedback control actions are taken based on local voltage and current measurements. However, based on a centralized scheme, there can be a graded response from the most local level to intermediate levels and so on, encompassing larger and larger geographical areas.

One method to orchestrate these schemes is “transactive control,” in which incentive signals are transferred down to lower levels of control based on global considerations of desired system (or subsystem) operation. Transactive control provides a means of coordinating the response of smart grid assets at all levels of the power system, extending the notion of locational marginal pricing throughout the system from generation to end use. However, the transactional nature of the technique introduces a new element in the use of a pair of signals to implement an equivalent to market clearing, distributed in space and time [12].

7.1 Inverter-Based Resources

Inverters that implement advanced grid functions can assist with bulk system frequency problems, distribution-level voltage deviations, and additional system protection and resiliency. These capabilities come at limited expense and can greatly increase the allowable penetration of PV and other renewable energy on the grid, reduce the need for ancillary services, and provide wide-area damping control. Many advanced grid functions are required in Europe and, more recently, in certain jurisdictions in the United States. National grid codes mandate advanced grid functions in PV and energy storage inverters for low- and medium-voltage interconnections [13].

Examples of inverter-based advanced grid functions include:

- Voltage stability
- Transient stability (transient real and reactive power control)
- Damping of small signal oscillations and/or forced oscillations
- Power quality (e.g., harmonics)
- Negative sequence current supply (for unbalanced faults and/or unbalanced load)

A key research goal that would enable inverter-based resources to become important assets for grid control is to improve the ability of these advanced inverters to provide valuable grid services while preventing conflicting and damaging inverter actions from causing harm to the grid. Inverters on the future grid will be asked to do more than in the past. This can lead to a more resilient grid but, if care is not taken in designing these new inverter features, inadvertent harm can be done to the grid. Unintended vulnerabilities can be introduced in inverter control designs that can lead to inverters competing with each other or even canceling out grid safeguards. These unintended vulnerabilities could also be exploited by adversaries to harm the grid. Despite these risks, the rush to increase inverter functionality and enable inverters to provide grid services has not been matched with study or mitigation of the grid-level consequences of these new “smart” inverters.

A more system-oriented approach is needed in designing control algorithms for large-scale inverters. This approach needs to be two-pronged. One prong is to design controls that can improve the economic value of inverter-based generation by leveraging inverters’ unique dynamic capabilities to provide essential grid services in addition to real power. The other prong is to embed control strategies in these inverters to prevent the unintended injection of power that can worsen dynamic stability conditions on the grid. This two-pronged approach can be summarized as the development of control algorithms for transmission-sited inverters to improve their economic value and versatility while ensuring that these resources “do no harm” to the grid. The development of these control algorithms would incorporate advanced control concepts, including optimal and adaptive controls that will consider a combination of financial, reliability, resilience, and stability metrics. Each application would be designed to achieve one or more control objectives and constructed to operate within safe bounds, ensuring the protection of the inverter resource and the interconnected system.

7.2 Power-Flow Technologies

DOE estimates that, by 2030, the amount of power that will pass through power-electronics-based devices at some point between generation and load is expected to reach 80%, both nationally and internationally. This dramatic increase in the use of power electronics on the grid will bring many benefits. The long-standing practice has been to use rotating machinery for system inertia. Power electronics can replace much of this system inertia and even improve upon it. However, there are some potential down sides to increasing reliance on power electronics. The stability issues and potential failure modes that are unique to power electronics need to be assessed, analyzed, and possibly mitigated. Although the potential for improved stability performance from increasing use of power electronics is certainly a benefit to grid performance, security and reliability issues that could be inadvertently (or deliberately) worsened by power electronics need to be addressed (see [14], [15] for studies of the potential impacts of power electronics on grid stability performance and grid architecture issues, respectively). Areas of research include: particular device types (FACTS, UPFCs, inverters, thyristors, HVDC, etc.), economics (cost-effectiveness, low cost, low maintenance, low installation, stackable benefits), modeling (systems-level models, uncertainty quantification), enhanced control (robustness, adaptive), distributed control of power electronics, power electronics at the distributed generation and microgrid level, grid-level stability (and instability), installation and maintenance, reliability, and security.

New technologies can provide fast, flexible, reliable power-flow control to ensure reliability while also maximizing efficiency on the transmission network. A potential benefit of these technologies is to reduce congestion on a practical, large-scale power system, and thus reduce system production costs. Key research activities needed in order to realize this benefit are [16]:

- Develop low-cost, efficient, reliable power-flow control devices, including power-electronics-based converters and controllable reactance, as actuators to enable improved controllability and flexibility of the grid
- Perform simulation and testing with communication and power-flow control device hardware
- Develop interoperability and diversity in communication protocols, including emerging low-latency communication to provide robust control
- Focus on implementation issues associated with emerging technologies, including tracking development of advanced and flexible grid-forming inverters associated with generation (wind/solar/battery resources) and transmission and distribution equipment, including HVDC and FACTS technologies

Common characteristics of new power-flow technologies include fast response times and flexible operation and control. Some of these technologies are also modular and can be moved from one location on the grid to another in a relatively straightforward way. Table 1 provides a high-level summary of these new technologies.

Table 1. New power flow-technologies and characteristics [17]

Device	Developers	Characteristics
Distributed Series Reactor	Smart Wires Inc.	• Increases line impedance on demand by injecting the magnetizing inductance of the single-turn transformer • Functions as a current limiter, diverting current from overloaded lines to under-utilized lines • Can provide local or centralized control • Availability of various device models and types
Compact Dynamic Phase-Angle Regulator	Varentec Inc.	• Integrates a power converter with a transformer • Uses special modulation technique to control angle of a module of the injected voltage, providing smooth and continuous real and reactive power-flow control
Transformer-less Unified Power Flow Controller	Michigan State University	• Uses cascaded multi-level inverters to eliminate transformers • Has fractional mega-volt ampere rating (10-20%) for changing (raising/lowering/reversing) power swing on typical line • Features modular scalable design
Magnetic Amplifier	Oak Ridge National Laboratory, SPX, Waukesha	• Inserts controlled variable inductance on a line • Isolates power electronics from the high-voltage line • Uses low-power DC source to control high-voltage AC inductance • Provides smooth reactance regulation, acceptable harmonics • Uses standard transformer manufacturing methods

DC = direct current; AC = alternating current

In [17], the following conclusions were noted:

- The more devices placed, the greater the benefit, but, as additional devices are placed on lines with fewer congestion costs, the incremental benefits decrease until a saturation point is reached.
- The greater the control range and the higher the limits of control, the greater the benefits. These increases have diminishing returns as well.
- Generally, systems with more renewable resources and higher fuel prices experience greater benefits.

7.3 Solid-State Transformers

The electricity grid comprises thousands of distributed three-phase 60-Hz alternating current (AC) generation assets, all of which must be kept precisely synchronized in frequency and phase. This synchronization requirement is what makes large AC electrical grids vulnerable to cascaded failure, such as the August 2003 blackout that left 50 million people in the United States and Canada without power [8]. Such cascaded failures have historically been the result of unintentional events. Our transition to an ever more interconnected and "smarter" grid has opened the door to a broader range of potential vulnerabilities.

New technology based on solid-state transformers (SSTs) has been proposed to significantly reduce the magnitude of the effects of any attack or disaster on the electrical system (see [18] for a survey on development of this technology). It has long been understood that replacement of conventional AC-AC transformers with AC-direct current (DC)-AC transformers that provide phase/frequency decoupling would be a potent remedy for cascaded failure. Accordingly, such devices, commonly referred to as SSTs, have been the subject of increasing research during the past decade. Current SST technology encompasses a very large number of semiconductor switches and bulky reactive components and falls far short of the required transformer efficiency. Research today is focused on constructing a fundamentally new type of bi-directional inverter topology based on temporally weighted non-linear rectification that meets the above requirements to mitigate cascading failure on the power system. This novel inverter topology would allow the construction of low-parts-count, highly efficient SSTs and should be ideally suited to interfacing DC assets (including solar PV generation, grid storage batteries, electric vehicles) with variable-frequency-AC-generation grid assets (such as wind).

The primary differences between conventional transformers and SSTs can be summarized as follows [19].

Conventional transformers:

- are passive devices
- are approximately 97-99% efficient
- can introduce harmonics

- pass disturbances along
- require a year or more lead time for replacement

SSTs:

- decouple phase and frequency
- provide reactive power control (VAR support, power factor correction).
- manage power quality
- have reduced footprint, deployment burden, and inventory overhead compared to conventional transformers
- have potential to correct certain kinds of phase imbalance
- enable (through "DC in the middle") natural integration of DC power sources, e.g., PV, energy storage
- are insensitive to frequency, enabling natural integration of variable-frequency AC sources, e.g., wind

Wide-scale deployment of SSTs would allow for entirely new paradigms of operating the power system, by introducing controllable interfaces in many more locations.

7.4 High-Voltage Direct Current Modulation

When the PACI was first energized in the early 1970s, 0.3-Hz spontaneous electromechanical oscillations were observed [20]. The system was inherently unstable where the collective inertia and controls associated with the generators coupled through the transmission network associated with the western power system. Electromechanical oscillatory modes are present in all interconnected power systems, but they generally are of little concern unless they are poorly damped. The typical conditions for lightly damped oscillatory modes are "long skinny systems" without much inertia in the middle. The western interconnection exhibits these conditions, particularly when heavily loaded with north-south power flows.

Numerous papers and research projects have been associated with the topic of detecting and controlling oscillations. To compensate for fast excitation systems that would contribute to this oscillatory behavior, power system stabilizers (PSSs) were developed and deployed. But PSSs generally work best to dampen local modes associated with the power plant oscillating with the system. Inter-area modes of oscillation, where the system is inherently lightly damped, are trickier to resolve. One of the earliest large-scale attempts at using active real power injection to dampen oscillations was carried out by the Bonneville Power Administration, which installed a 30-megajoule superconducting magnetic energy storage coil at the Tacoma substation in the early 1980s [21]. The device was abandoned after its liquid helium cryogenic refrigerator failed. Another method was tried, modulating the power associated with the PDCI to dampen these oscillations.

The PDCI is an HVDC facility that was first energized in 1970 and has been upgraded over the years to have a 3,220-MW transfer capacity. The terminals, in Cello, Oregon and Sylmar, California, are separated by 846 miles [22].

HVDC is useful under specific circumstances. It has only two wires, compared to three for traditional AC transmission lines, so HVDC towers and conductors are less expensive per mile. Resistive losses are also slightly less, without the skin effect associated with 60 Hz where the current does not flow evenly across the cross section of the conductor. However, the capital cost and energy losses associated with converting the AC to DC and back again to AC mean that HVDC technology is only used in specific applications, such as moving a large amount of power over a long distance (this is how the PDCI was justified). Another example is connecting different synchronized systems (the western and eastern interconnections or Texas and Quebec). If there is a cable involved (e.g., undersea), DC has technical and efficiency advantages over AC, and the break-even point in terms of distance and power capacity will be more favorable for DC in those circumstances.

Modulating the PDCI was found to be an effective means for dampening the 0.3-Hz oscillations that were observed on the PACI. However, one of the challenges associated with modulating the PDCI is that, without wide-area visibility, it is possible to destabilize other far-flung parts of the system while attempting to dampen the oscillations being observed at the terminals of the PDCI [23]. The coupling of the various electromechanical modes in the network creates a complex, interdependent situation in which small changes can have unintended consequences. In the 1980s when the Bonneville Power Administration was experimenting with PDCI modulation, testing revealed that, under some operating conditions, the risk of undesirable effects was significant. This led to the recommendation to provide a wide-area measurement system (WAMS), a network of time-synchronized power system monitors that can measure electromechanical modes of oscillation.

One of the other problems associated with relying on the PDCI to provide dampening to inter-area oscillatory modes is the limiting contingency of the loss of the PDCI line itself.

By 2020, we have achieved significant advances in wide-area visibility with instruments that can accurately measure electromechanical oscillations. Therefore, we now have the ability to assure that various methods of wide-area control, including but not limited to HVDC modulation to dampen oscillation, are now technologically feasible.

More broadly, HVDC is a mature technology that is broadly deployed in transmission systems worldwide. HVDC systems have proven economical for transferring bulk power over long distances, for undersea applications, for isolating AC systems, and for interconnecting asynchronous networks. Voltage source converters (VSCs) are a recent technological advance that provides more flexibility and simplicity in system designs. VSCs also have inherent black-start capabilities, enable multi-terminal configurations, and are easier to deploy. However, this technology faces challenges with power ratings, efficiency, and cost. Opportunities exist to improve the cost-effectiveness of VSC technology by increasing system efficiency. Reducing losses from 1.4% - 1.6% per converter to 0.7% would make VSCs comparable in efficiency to traditional HVDC line-commutated converters [24]. Costs for HVDC converter stations can be reduced by leveraging new designs, new topologies, and advanced power electronic devices. Newer materials would allow for higher-temperature and higher-frequency operation, translating to smaller passive components and thermal management systems and thereby reducing overall system costs.

In addition, new power-electronics device architectures can fundamentally change the design paradigm for HVDC. Today's technologies are based on vertical devices. Research in modular multi-level converters could enable higher-voltage, higher-power applications, using market-available semiconductor devices. Modular multi-level converters reduce stress on switching components, which enhances reliability. Multi-terminal HVDC networks (MTDCs) have been used in offshore wind collector systems but have the potential to enhance system reliability for onshore applications as well. Controls for coordinating MTDC terminals must be perfected before commercial systems are widely deployed. Medium-voltage DC converter applications should also be assessed, including, for example, improving resilience by connecting substations, increasing efficiency through DC distribution buses, and operating with nested or networked microgrids.

MTDC networks are currently at the research stage. These networks have potentially more controllability and flexibility than point-to-point HVDC and therefore the potential to provide enhanced inter-area oscillation damping to large AC interconnections. In the case of point-to-point HVDC lines, damping technology has been both modeled and demonstrated for the case in which a line exists between areas that exhibit oscillations [25]. Nevertheless, for both point-to-point and MTDC configurations, multiple research questions need to be addressed to further evaluate the potential for HVDC/MTDC in transmission grid controls [26]. These questions include:

- How robust is the damping system? How will it operate under a variety of adverse conditions? What if there is a communication problem? How will the controls interact with system protection?
- To what extent can the power be modulated? What are the limiting factors on the AC side and the DC side? Are short-term limits different from long-term limits?
- What factors limit the usefulness of modulation? How different are they from case to case?
- How would HVDC modulation for damping inter-area oscillations affect other power system problems, such as transient stability or frequency regulation?
- As more HVDC lines are installed, will it be possible to coordinate their operation?
- As MTDC configurations are built, what new applications are needed to take full advantage of their controllability?

8. Design of Control Architectures to Leverage New Communication and Sensor Technologies

The future grid will generally be characterized by more sensors, more communication, more computation, and more control, but a comprehensive conceptual architecture is seldom presented. Putting the component technologies together into a coherent whole and transitioning from the current grid to the future grid will be a significant (and expensive) undertaking. Therefore, an important research task related to deploying new automatic controls on the transmission system will be to design the organization, structure, and information flow of grid controls to achieve maximum reliability, resilience, and security [27].

It has become well accepted that new information technologies will enable the North American electric power system to enhance its control and protection schemes to increase its reliability and efficiency. Moreover, the trend toward higher penetration of non-traditional, power-electronics-coupled renewable generation resources will depend heavily on our ability to develop these control and protection schemes. Research and development are currently focused on customized solutions to grid operation challenges in targeted locations [28]. However, these one-of-a-kind, special control and protection schemes are very expensive. A streamlined process needs to be developed for design, installation, operation, and maintenance of control/protection schemes, along with a conceptual framework for approaching these problems. New technologies are making it possible to move away from protection and primary control that rely on local information and meet (predominantly) local objectives, toward distributed control and protection devices that use wide-area information and reflect system-wide objectives. The new framework for approaching grid protection and control should be hierarchical so that subsystems as well as the whole system can be covered and at the same time coordinated both across the power system (geographically) and across voltage levels.

Automatic grid control technologies are poised to address a significant number of future grid challenges, especially those arising from a rapidly increasing penetration of intermittent, non-dispatchable renewables. Advances in sensing technologies are making new information available about various aspects of the grid, and progress in communication technologies is making this information available at pertinent locations. Automated decision making is therefore becoming feasible, at time scales from seconds to seasons; and at desired, new, and distributed locations. This shift will facilitate a variety of opportunities for control to reduce consumption, to better exploit renewable sources, and to increase the reliability and performance of the transmission and distribution networks.

Increased deployment of feedback and communication implies that loops are being closed where they have never been closed before, across multiple temporal and spatial scales. In this context, control systems are needed to facilitate decision making under myriad uncertainties; and across broad temporal, geographical, and industry scales—from devices to system-wide, from fuel sources to consumers, and from utility pricing to demand response [29]. The extent to which human operators can cope with the increasing complexity of these automation schemes will need to be addressed. The challenges introduced by automation schemes can be posed as a system-of-systems problem, necessitating new control themes, architectures, and algorithms. These architectures and algorithms should be designed so that they embrace the resident complexity of the grid: large-scale, distributed, hierarchical, stochastic, and uncertain. With information and communication technologies as well as advanced power electronics providing the infrastructure, these architectures and algorithms will need to provide the “smarts,” utilizing all advances in communications and computation. The challenges of designing completely centralized control architectures as well as completely decentralized control architectures can be mitigated using a hybrid approach. Figure 3 illustrates a two-level, hybrid architecture in which a centralized controller can interact with multiple decentralized controllers [29].

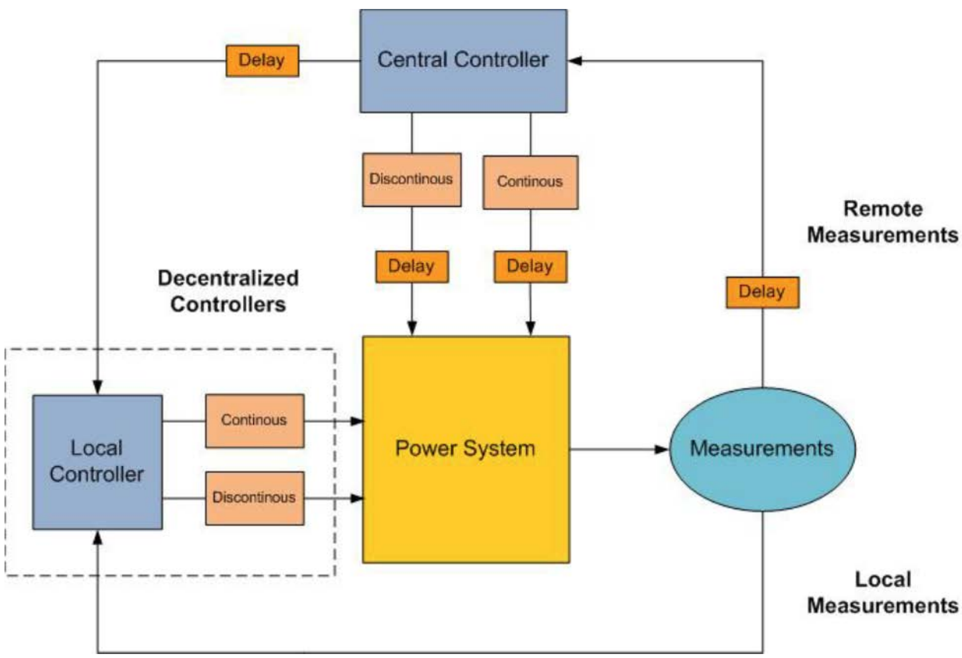

Figure 3. Hybrid control architecture combining centralized control with decentralized controls [29].

The grid of the future will need to provide fast, wide-area, reliable measurements and system health-status information as inputs to controls. Table 2 provides an overview of the observability and controllability characteristics needed for the future grid.

Table 2. Monitoring and control attributes necessary for the future grid [24]

Observability	Controllability
Dynamic, fast, global perspective: • Resource forecasts • Interdependencies • Grid stress • Grid robustness • Dangerous oscillations • Frequency instability • Voltage instability • Reliability margin • Field asset status	Predictive, probabilistic, system-wide coordination: • Generator dispatch and control • Topology and flow control • Demand-side coordination • Management of risk – resilience

Even with ubiquitous, low-cost, reliable communications, there are still fundamental reasons to separate fast-acting local control from global optimization and control algorithms. One key reason is communication latency. The time delays that are involved in collecting information, forwarding it to a control center, processing it to compute a solution, and relaying the solution back to the actuators in the field pose a challenge for fast-acting controls. Excluding all time associated with processing (sensing, communications equipment processing, algorithm computing time), the speed of light for transmitting a signal round-trip across 100 miles requires more than a millisecond of communication latency.

The time delay introduced by transmission of information to a control center is only one consideration. Another significant issue is creating a dependency on communications for real-time controls. There is a tradeoff between maximum economy (or optimization) that is enabled by centralization versus maximum security (or resilience) through distributed approaches for critical functionality. In general, resilience could be compromised when the grid depends more heavily on communications to function reliably.

A compromise is a hybrid approach in which fast-acting controls rely on local feedback signals. If set points and situationally dependent instructions for how the remote devices should behave under the prevailing operating conditions are disseminated, then remote actuators can be controlled by localized feedback signals. It will be essential to have robust fail-safe control schemes in place so that the overall operation is resilient to communication failures and disruptions, including cybersecurity compromises.

One option to enhance the robustness and security of control schemes is to use state estimation technology to gather measurement data and fit those data to a real-time model that provides input to the control algorithm. Properly designed, this approach would reduce the impact of communications failures and enhance the fail-safe aspects of the control scheme. Distributed approaches to dynamic state estimators and linear state estimation with time-synchronized data need to be further developed to enhance the prospects for reliable, robust wide-area control schemes.

9. Microgrids as Distributed Resources for Grid-Wide Controls

Control systems are a crucial component of power grids and play a major role supporting power system stability and performance. Historically, power systems started as purely local, islanded infrastructures, serving entities like cities or industrial production sites. The interconnection of neighboring power systems has improved system reliability and economy of operation. These benefits have been recognized, and interconnections have, therefore, continued to grow, producing very large systems of enormous complexity. The integration of fluctuating or distributed energy sources such wind and solar power into these networks is creating new challenges for power system control and operation. The high growth rates of distributed generation will require that the concepts of decentralized management and control of these resources be more rigorously addressed than they have been in the past.

Among the ancillary services that microgrids can provide to the main grid, the most commonly discussed are the voltage control and reactive power. Additional services include active power supply, power loss compensation, re-dispatch capability, spinning reserve, and suppression of sub-harmonics [30].

The prospect of "islandable" microgrids that can self-organize and disconnect from and reconnect to the larger system (along the lines of the previous adaptive islanding discussion) presents a key challenge for their controllability. How can these schemes be automated and trusted to operate correctly under a wide range of operating conditions without compromising safety and other operational constraints?

Future research should address easy-to-evaluate (analytical) stability criteria, decentralized (self-organizing) strategies for energy and power management, fault-correcting control, stable and resilient operation of hybrid DC and AC power systems, and efficient use of newly available sensor technology such as PMUs for grid control. All of these topics must confront particular challenges when in-feed is inverter driven, e.g., from PV or wind power. The rise of power electronic equipment on the grid and the coupling of our electrical power system to other energy sectors, such as heat/cold supply or the transportation infrastructure via electro-mobility, will have significant impact on the requirements for grid control systems.

10. Electricity Storage Systems

Electrical energy storage technologies are characterized by their bi-directional response capability to store and discharge electric power on command. These technologies can provide various benefits to the grid, such as supporting system balance, improving economic dispatch, enhancing power quality and stability, and enabling utilities to defer infrastructure investments. Certain electricity storage technologies can also be deployed in communities or behind the customer meter to contribute to emergency preparedness and grid resilience. The future grid will likely require a substantial deployment of electrical energy storage to provide system flexibility and enhance control capabilities.

Today, pumped hydro accounts for more than 95% of energy storage in the United States. However, siting constraints, environmental concerns, and cost make new, large-scale deployment of pumped hydro storage difficult. With increasing penetration of variable renewable resources, the grid's need for operating reserves is expected to increase. Energy storage technologies can meet this need. Many electrical energy storage technologies are available, and each has distinctive performance characteristics that make it more suited for particular grid applications. A technology's applicability can be determined primarily according to its power rating and energy capacity. Other technical characteristics to consider are round-trip efficiency, cycle life, depth of discharge, and ramp rate.

One of the major challenges common to various storage technologies is cost. It is important to consider the cost of all subsystem components as well installation and grid integration. Although there is a strong focus on reducing the cost of the "energy storage" component of a technology, such as the battery chemistry or the spinning mass in a flywheel, this component accounts for only approximately 30%–40% of the total system cost [24]. An approach is needed to reduce balance-of-system costs to achieve both the desired total cost and performance targets. Other challenges include improving the safety of these technologies and assessing the appropriate value streams for the multiple services that electrical energy storage can provide.

Fast-acting storage has the potential to significantly increase grid efficiency, stability, and resiliency. Such storage, if appropriately deployed, could give grid operators a flexible, fast-responding resource for effectively managing variability in generation and demand. Energy storage can provide a number of grid benefits, which are typically categorized according to their time scale. On a slower time scale are energy supply interactions, in which large amounts of energy are supplied or pulled from the grid. These are often referred to as ``energy'' applications. By contrast, ``power'' applications normally transpire on a much faster time scale and are employed to support real-time control of the grid. Table 3 summarizes some of the more well-known energy storage applications.

Table 3. Summary of Energy Storage Applications [31].

Energy Applications	Power Applications
Arbitrage	Frequency regulation
Renewable energy time shift	Voltage support
Demand charge reduction	Small signal stability
Time-of-use charge reduction	Frequency droop
Transmission and distribution upgrade deferral	Synthetic inertia
Grid resiliency	Renewable capacity firming

To achieve efficient operation of large-scale energy storage systems, two main engineering challenges need to be addressed:

1. Optimal scheduling of grid energy storage to guarantee safe operation while delivering the maximum benefit
2. Coordination of multiple grid energy storage systems that vary in size and technology

To solve these engineering challenges, sophisticated energy storage management systems are required that monitor and optimally control each energy storage system and interoperate multiple energy storage systems.

Closely related challenges include:

1. Virtual power plant operation, which typically involves control of distributed generation, demand response, and energy storage to emulate the characteristics of a traditional generator
2. DER management and decentralized control of DER via microgrids
3. Energy management for vehicle-to-grid and grid-to-vehicle applications of plug-in electric vehicles

An application that has received recent attention is the use of distributed energy storage to improve grid stability by, for example, damping of power system oscillations. Using distributed energy storage for grid stability control has both potential advantages and disadvantages [32]:

Advantages:

- Robust to single points of failure
- Size/location of a single site less critical as more energy storage is deployed on grid
- Energy-neutral control signal that is short in time duration enabling storage sites to perform other applications
- Variations in geographic location for enabling control of multiple oscillation modes
- Modest size of any individual deployment when a large number (i.e., greater than 10) storage systems are participating in a control strategy
- Possibility of hybrid control strategies that combine distributed storage with other sources of power injection, e.g., PSSs, SVCs, HVDC

Disadvantages:

- Time delays in feedback signals that can cause the damping control to destabilize the system (stability depends on size of delay as well as the size of control gain)
- Cyber security concerns for network-based approaches
- Insufficient storage currently deployed on grid to enable demonstrations of control strategies

With multiple energy storage devices available throughout the system, it may be advantageous to use smaller power injections from multiple devices at favorable locations rather than using larger power injections from fewer devices in poorly chosen locations. Performance of distributed storage in a damping control application can be improved with almost any type of real power injection, but performance depends strongly on injection sizes and locations. There are trade-offs among choosing larger or smaller injections, more or fewer storage devices, and different locations [33].

Because of the fast-growing importance of batteries on the grid, properly managed integration of batteries in both distribution and transmission can be considered one of the most effective solutions for inter-area oscillations on the future grid [34]. Batteries can both absorb and inject both active and reactive power. This characteristic provides a unique opportunity to manage a battery's output power to improve grid stability.

The size and complexity of the power system pose significant challenges to designing and implementing centralized control, which is why decentralized control methods have been widely used. In decentralized control, a subsystem controller does not rely on information exchange from different areas. The need for rapid control actions also dictates decentralized control solutions. The main advantages of decentralized control are greater computational efficiency of systems, greater reliability of estimators resulting from the distribution of resources, and scalability of controllers designed for large systems.

11. Improved Numerical Methods for Dynamic Simulation

The dynamic simulation tools used by the transmission planning community have evolved significantly over the years to address the simulation needs of the power industry. This is particularly true of transient stability simulation programs. Visualization, data handling, batch processing, dynamic models, and network representation are some of the areas in which today's simulation capabilities are far more sophisticated than those of the past. The evolution in simulation capabilities has been driven by the industry's need for an accurate representation of the dynamic performance of power grids. As new generation technologies are introduced, their dynamics must be represented in modeling tools. As simulation tools improve, so will our understanding of power system behavior when generation consists of a high penetration of renewables coupled with slower dynamics such as AGC and variations between forecasted and actual renewable generation. Enhanced understanding of the interaction between slow and fast dynamics will be critical for designing wide-area automatic controls because of the need to anticipate how inverter-based resources will react to slower dynamics (e.g., AGC) and vice versa. As simulation speeds and accuracy improve, control design, which relies heavily on simulations, will likely improve, leading to improvements in grid reliability and resilience. In addition, improved simulation tools will enable improved grid planning, which can, in turn, reduce barriers to high penetration of renewables on the grid.

In the context of transient stability simulations, wind and solar power plants have two inherent characteristics that set them apart from traditional power generation provided by synchronous generators: a) they interconnect with the power grid via electronic converters, and b) their power supply is inherently variable. Items a) and b) involve the simulation of fast and slow dynamic phenomena, respectively. Item a) poses the problem of modeling and simulating the interface of a fast dynamic component (the electronic converter) with a slower time-varying network (the power grid). Item b) means that simulations must span time frames much longer than those associated with typical transient stability studies. Additionally, the widespread inclusion of wind and solar results in a low-inertia system, increasing the rate of change of frequency in response to transient events.

The numerical integration algorithms currently used in North America were not designed to study the vastly different dynamic phenomena associated with variable renewable generation. When generation consists of large quantities of renewables, the power industry needs improved simulation tools that allow a more realistic representation of power system transients. This translates into the need for research and development of numerical methods to simulate the fast and slow dynamics associated with renewables over longer time frames, in order to observe the impact of these energy sources on the rest of the power grid.

Numerical algorithms for solving the differential-algebraic equations that represent power system dynamics of an interconnected grid compute the state variables and bus voltages in those equations at discrete times. For most transient stability simulations, these times are equally spaced; that is, the integration time step is fixed. Typical time domain simulations for power system planning studies that cover a time frame spanning 15-30 seconds will use a fixed integration time step, usually with a value near ¼ cycle = 4.167 milliseconds in a 60-Hz system.

Many numerical methods exist for solving differential-algebraic equations; however, the intrinsic properties of large power systems limit the types of numerical algorithms that can be effective in simulations of power system dynamics. These intrinsic properties are system size, component diversity, and sudden switching events. Because of these properties, effective numerical algorithms must not impose an excessive computational burden but must also:

- provide sufficient accuracy
- include an efficient adjustment of integration step size
- allow the use of longer time steps when the system is in quasi-steady state

As noted earlier, with the rapid integration of renewables on the grid, simulation time frames need to be extended to account for variable PV and wind generation over long time periods. One approach is to use a variable time step for integration. In this approach, the time step can increase as fast transients subside; conversely, the time step can be reduced to capture fast transients. This permits a reduction in the number of necessary iterations and supports the use of more complex integration schemes. This approach relies on time-step control, which estimates the error at each iteration and adjusts the time step to meet a tolerance threshold (see [35], [36], [37] for development of variable time-step methods).

Another approach to extended simulation times is the use of multi-rate methods. In this approach, a small time step, called a sub-interval, is used to calculate fast-changing variables. A longer time step is used to calculate slow-changing variables. The sub-interval integration approach, coupled with a longer main time step, allows for network algebraic equations and slow dynamic equations to be evaluated much less frequently than is needed for fast dynamic equations, which is a computational benefit (see [38] for a survey of multi-rate methods, and [39] for a study of the improvement in speed and accuracy from using multi-rate methods on several representative grid examples).

In addition to the above classes of numerical solvers, other techniques can be employed to improve the efficiency of solving differential-algebraic equations. For example, systems with noise and modeling uncertainties can be studied using improved error analysis of numerical methods. Further computational benefits can be realized by improved modeling of key grid components, such as AGC (slow dynamics) and inverters (fast dynamics), for both the grid-forming and grid-following types of inverters. This is especially true for capturing the types of dynamic behavior exhibited by inverters during recent events such as the Blue Cut Fire and Canyon Fire that caused outages of large PV power generation facilities in California (see [40] for a discussion of proposed new models for inverters and limitations of current models). Parallel computing can also be used to simulate dynamics of large-scale power systems. Parallel computing methods assign different operations within a simulation to different processors to be computed simultaneously. The potential reduction in run time is proportional to the number of processors used in parallel. An adaptive modeling framework is another simulation technique that can be used, in which the simulation software switches between classical transient simulation and long-term time sequenced power-flow simulation, depending on the speed of the dynamic phenomena being solved.

12. Control Capabilities to Improve Grid Restoration (Black Start)

There has been a large amount of research on grid restoration techniques during the past 20 years (see [41] for a comprehensive study of the methodologies in use today for prioritizing and allocating available grid resources for the black-start process). However, there has been limited research into the use of inverter-based resources as part of a black-start process for large power grids (see [42], [43], [44] for recent work in this area). In this situation, the black-start process would begin with synchronous generators applied first to establish a 60-Hz waveform that could then be used by grid-following inverters participating in system restoration. However, there has been a significant increase in the study of, and commercial interest in, grid-forming inverters that do not need a pre-existing 60-Hz waveform to participate in the initial stages of the black-start process. Research and development should be directed toward the use of inverter-based assets for black start, especially because the penetration of such assets is expected to accelerate during the next 20 years.

Another aspect of grid restoration that needs further research and development is the operator's role in black start of a grid. Critical judgments must often be made in the face of incomplete or erroneous information about the system state. Recent cyber-attacks on power systems create the prospect of maliciously corrupted information or blocked control. These considerations highlight the value of improving our understanding of operators' behavior under extraordinary and possibly unprecedented conditions. Formalizing this understanding in appropriate models will allow a more comprehensive approach to resilience design. Optimization studies can be enlarged to include information flows into operators' decision processes and risks arising from restoration decisions predicated on an incorrect picture of the system. Different processes for information-sharing among operators of interacting systems can be evaluated and stress-tested (see [45] for examples). Techniques such as machine learning have advanced to a level at which they can be applied to understanding and complementing operator behavior.

13. Hardening Against External Threats

The control schemes previously described in this paper must be designed so that they are resistant to disruption by external threats, such as extreme weather, earthquakes, cyber security breaches, physical attack, geomagnetic disturbances, and electromagnetic pulses. This is one of the reasons that it is imperative that control schemes can act autonomously without reliance on wide-area communications during emergencies. The design of the control systems themselves should also be hardened according to best industry practices for critical civilian infrastructure. Particularly for schemes that could have wide-ranging impact, such as controls associated with the bulk power system, it is of paramount importance that operations be robust, resilient, and secure.

Because many of the advanced control schemes described in this paper require communications and computational capabilities, cyber security will be of critical importance. Some controls will be distributed yet interconnected, meaning that security measures will be needed to prevent cascading security failures. The implementers of these schemes will need to consider various failure modes, including the consequences of losing communications or, more importantly, maintaining the integrity of these communications. Failsafe countermeasures will need to be designed accordingly. For example, robust mechanisms to ensure authentication of control signals are very important for controls that can have a significant impact on the power system.

One of the limitations of existing cyber-security controls implemented in North America is an artificial separation between cyber assets associated with transmission and distribution systems. Because these systems are often interconnected, it is important to consider the vulnerabilities and potential impacts associated with these systems holistically. Countermeasures need to be carefully implemented so that the effectiveness of the controls is maintained under a wide range of operating conditions. If controls may be operating under severe (and potentially unanticipated) conditions, the overall resilience of the control schemes need to be maximized.

Design of a control system needs to consider credible contingencies for various elements of the entire system (some credible contingencies can simultaneously impact multiple individual elements). Plans for restoration from extreme events need to be developed and tested.

14. Path Forward

There is no shortage of ideas about how to enhance grid reliability and resilience using advanced wide-area controls [46]. Many well-reasoned research papers have been written that are supported by solid theory and extensive analytical simulation. What is missing is a clear roadmap for developing and deploying these advanced technologies to systematically leverage incremental progress and enable experts to learn from the experiences of others as innovations are implemented. Furthermore, a business case needs to be made so that utilities, equipment and technology suppliers, vendors, and other stakeholders see a clear, compelling benefit from substantial investments in the technologies described in this paper. Regulatory support for advanced technology deployment is paramount, as is a fast track from conceptual design to field prototype demonstration and eventual wide-scale deployment. DOE can play an essential role in convening stakeholders and driving toward consensus on a compelling roadmap that includes incremental direction and long-term vision, as well as in providing continued support of technology research, development, and demonstration.

The successful North American Synchrophasor Initiative (NASPI) offers a template for advancing this vision. Following the advent of ubiquitous, precise time synchronization, system operators have been replying on synchrophasor measurements to enhance system reliability for several years [47]. The benefits of this technology became apparent after high-visibility reliability events. Those events include the August 10, 1996 blackout on the Western Interconnection when advanced wide-area measurement systems revealed undamped oscillatory behavior, and the August 14, 2003 blackout on the Eastern Interconnection when system failure was attributable to lapses in wide-area situational awareness. As a result of these experiences, DOE, working closely with stakeholders from industry and academia, has been nurturing the deployment and utilization of wide-area measurement technology. The DOE Transmission Reliability Program began supporting research on WAMS in the 1990s. In 2002, DOE launched the Eastern Interconnection Phasor Demonstration Project with strong support from the utility industry.

NASPI was initiated in 2006, bringing together the efforts under way in the Western and Eastern Interconnections to create a structure for convening relevant stakeholders to promote and advance the widespread deployment of synchrophasor technology [48]. Establishing a forum for sharing best practices and lessons learned, NASPI organized around teams of volunteers from industry and academia to write white papers and other technical reports, which ultimately formed the basis for many technical standards that were eventually promulgated by the Institute of Electrical and Electronics Engineers and others. When the American Recovery and Reinvestment Act of 2009 included a substantial opportunity for smart grid investment grant funding, NASPI helped coordinate efforts related to synchrophasor deployment [49]. The impact of the resulting grant-funded synchrophasor efforts was magnified as a direct result of NASPI's role coordinating deployments and providing a forum for broadly sharing their successes. DOE has also continued to provide funding opportunities to industry and academia through the years, coordinated through NASPI, which has also organized regular work group meetings and task team activities. As many utilities have installed a large number of PMUs, the emphasis has shifted in recent years toward advanced networking and communications technologies to support large-scale deployments. Also, as the volume of data from these devices has increased dramatically, there is more interest in statistical analysis and deep learning for extracting actionable information from the large data sets. With the advent of more inverter-based resources on the grid along with events revealing the need for higher-speed measurement, there is emerging interest in high-resolution sensors to characterize the transient behavior of inverter-based resources and other fast-acting phenomena [50].

As DOE moves forward with the recommendations associated with the white papers in this series, NASPI can be used as a template for an organizational structure that would convene the appropriate stakeholders to support the development of a comprehensive research, development, and demonstration roadmap for transmission technologies for the future power grid and to provide a venue for sharing lessons learned and best practices associated with wide-area monitoring and protection and control, which are the specific focus of this white paper.

15. Summary of Research and Development Recommendations for Automatic Grid Controls

Table 4. Summary of research and development recommendations for automatic grid controls

Topic	Recommendations
Response-Based Remedial Action Schemes	• Rigorously develop, and validate with comprehensive engineering simulation and field demonstration projects, entirely new remedial action scheme designs that are response-based (vs. traditional event-based schemes) and provide flexibility and robustness to a wider range of off-normal conditions
Adaptive Islanding Schemes	• Develop pre-planned automatic controls to isolate portions of the grid to prevent an uncontrolled cascading failure, thereby limiting the extent of a disruption to the smallest possible area during system emergencies or incipient cascading failure conditions; although impossible to fully test in the field prior to implementation, evaluate for efficacy through comprehensive modeling and simulation • Ensure frequency and voltage control occurs seamlessly during the transition • Maintain optimal management of load and generation resources during both grid-connected and islanded modes
Control Architectures	• Develop new control algorithms that combine engineering and economics, incorporate optimization, and address robustness of massively networked large-scale systems • Develop distributed, real-time, closed-loop architectures that accommodate uncertainties in renewable generation and match supply to demand by making use of wide-area real-time information, and that decompose global objectives into coordinated local algorithms • Research distributed architectures that ensure safety and stability of the grid in the presence of incomplete and intermittent information • Develop scalable algorithms that are deployable at a huge distributed scale, supported by local decisions and global coordination
Inverter-Based Resources for Control Actuation	• Assess feasibility of, and develop, control designs for, inverter-based resources in applications including voltage stability, transient stability (transient power-quality control), damping of small signal oscillations and/or forced oscillations, power quality (e.g., harmonics), and negative sequence current supply (for unbalanced faults and/or unbalanced load) • Design coordination control strategies to prevent inverters from conflicting with each other or canceling out needed safeguards, thereby worsening dynamic stability conditions • Coordinate distributed control designs using large numbers of inverters to meet global grid control objectives • Develop virtual power plants that use distributed generation, demand response, and energy storage to emulate the characteristics of a traditional generator • Study time-delay limitations of real-time (and near-real-time) feedback signals that can destabilize the system, and mitigations/warnings for such scenarios

Topic	Recommendations
Power Electronics Devices for Control Actuation of the Bulk Power System	• Study potential for phase and frequency decoupling (e.g., as in FACTS, HVDC, or SSTs) to mitigate cascading grid failures
Improved Dynamics Simulation Tools	• Improve error analysis and study of uncertainty propagation in numerical solvers to improve simulation accuracy and speed • Investigate advanced simulation frameworks, including parallel computing and adaptive modeling
Controls for Grid Restoration	• Define roles for grid-following and grid-forming inverters that can be used with black-start restoration • Devise techniques for sequencing of inverters with other power generation resources in black start • Develop strategies to mitigate risks to the grid from using inverter-based generation for black start • Model operator behavior during black start • Apply machine learning and artificial intelligence techniques to black-start process
Controls to Harden Grid to External Threats	• Develop dynamic modeling and strategies that combine game theory, machine learning, and adaptation in the face of unknown, irrational, and adversarial market players and external threats

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